Oil and Gas Supply Module

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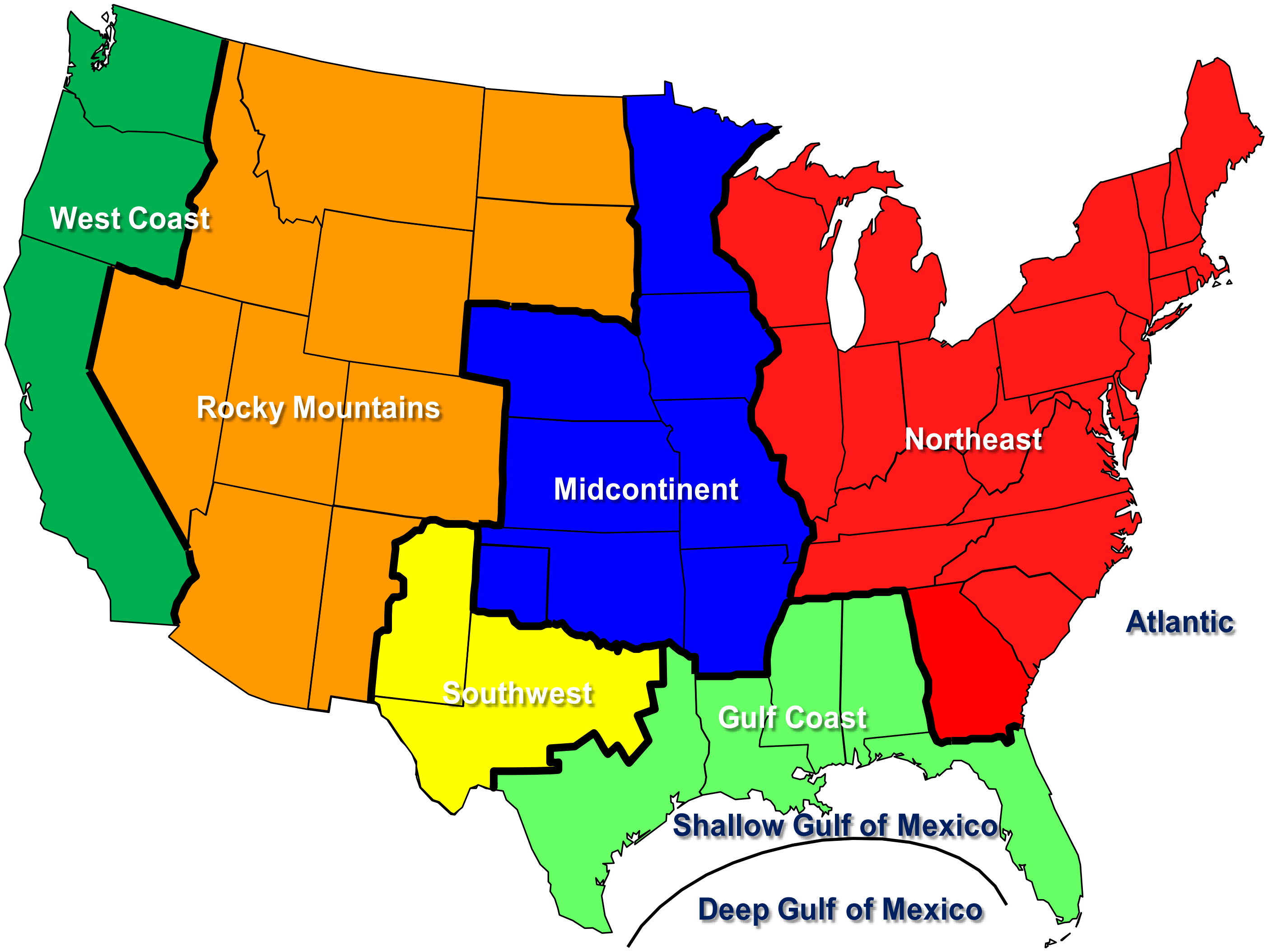
The NEMS Oil and Gas Supply Module (OGSM) constitutes a comprehensive framework with which to analyze crude oil and natural gas exploration and development on a regional basis (Figure 8). The OGSM is organized into 4 submodules: Onshore Lower 48 Oil and Gas Supply Submodule, Offshore Oil and Gas Supply 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, Model Documentation Report: The Oil and Gas Supply Module (OGSM), DOE/EIA-M063(2011), (Washington, DC, 2011). The OGSM provides crude oil and natural gas short-term supply parameters to both the Natural Gas Transmission and Distribution Module and the Petroleum Market Module. The OGSM simulates the activity of numerous firms that produce oil and natural gas from domestic fields throughout the United States.

Figure 8. Oil and Gas Supply Model regions



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

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 oil and natural gas technically recoverable resources

The outlook for domestic crude oil production is highly dependent on upon 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 that consist of proved reserves [3] and unproved resources [4]. Estimates of TRR are highly uncertain, particularly in emerging plays where 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 9.1 and 9.2 reflect the removal of intervening reserve additions and production between the date of the latest available assessment and January 1, 2011.

Table 9.1. Technically recoverable U.S. crude oil resources as of January 1, 2011
billion barrels

	Proved Reserves	Unproved Resources	Total Technically Recoverable Resources
Lower 48 Onshore	17	125	142
Northeast	0	3	3
Gulf Coast	2	27	29
Midcontinent	2	15	16
Southwest	6	32	38
Rocky Mountain	4	25	30
West Coast	3	24	26
Lower 48 Offshore	5	49	54
Gulf (currently available)	4	37	41
Eastern/Central Gulf (unavailable until 2022)	0	4	4
Pacific	1	7	7
Atlantic	0	1	1
Alaska (Onshore and Offshore)	4	34	38
Total U.S.	25	208	233

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 OCS is also excluded from the technically recoverable volumes because leasing is not expected in these areas by 2040.
Source: Onshore, State Offshore, and 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 reserve additions between the date of the latest available assessment and January 1, 2011.

Table 9.2. Technically recoverable U.S. natural gas resources as of January 1, 2011
trillion cubic feet

	Proved Reserves	Unproved Resources	Total Technically Recoverable Resources
Lower 48 Onshore Non Associated Natural Gas	261	1,321	1,582
Tight Gas	81	435	517
Northeast	3	34	37
Gulf Coast	18	181	199
Midcontinent	5	22	27
Southwest	3	12	15
Rocky Mountain	52	179	232
West Coast	0	8	8
Shale Gas	94	543	637
Northeast	16	239	255
Gulf Coast	25	143	168
Midcontinent	22	53	75
Southwest	31	58	89
Rocky Mountain	0	38	38
West Coast	--	12	12
Coalbed Methane	17	121	139
Northeast	2	4	6
Gulf Coast	1	2	3
Midcontinent	1	38	39
Southwest	1	6	6
Rocky Mountain	13	60	73
West Coast	--	10	10
Other	68	222	289
Northeast	10	29	39
Gulf Coast	14	105	119
Midcontinent	22	23	45
Southwest	12	24	36
Rocky Mountain	9	27	36
West Coast	0	13	13
Lower 48 Onshore Associated-Dissolved Gas	21	179	200
Northeast	0	2	2
Gulf Coast	2	43	45
Midcontinent	2	13	15
Southwest	10	48	57
Rocky Mountain	5	50	55
West Coast	2	23	25
Lower 48 Offshore	14	258	272
Gulf (currently available)	13	214	227
Eastern/Central Gulf (unavailable until 2022)	--	21	21
Pacific	1	10	11
Atlantic	--	12	12
Alaska (Onshore and Offshore)	9	273	282
Total U.S.	305	2,031	2,335

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 OCS is also excluded from the technically recoverable volumes because leasing is not expected in these areas by 2040.
Source: Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS) with adjustments to tight gas, shale gas, and coalbed methane resources; 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 reserve additions between the date of the latest available assessment and January 1, 2011

The remaining unproved TRR for a continuous-type shale gas or tight oil area is the product of (1) land area, (2) well spacing (wells per square mile), (3) percentage of area untested, (4) percentage of area with potential, and (5) 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 9.3-9.4. The model uses a distribution of EUR per well in each play and often in sub-play areas. Table 9.5 provides an example of the distribution of EUR per well for each of the Bakken areas. The Bakken is subdivided into three areas: Montana, North Dakota Core, and North Dakota Extension. The North Dakota Core represents the portion that is considered to be the "sweet spot" and has the highest well production rates, while the "Extension" area refers to the bulk of North Dakota that has less productive wells. Because of the significant variation in well productivity within an area, the wells in each Bakken area are further delineated into three well productivity categories: top 15%, middle 70%, and bottom 15%. This level of detail is provided for select plays in Appendix 2.C of the *AEO2013* Documentation for the OGSM. 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.

The AEO TRRs incorporate current drilling, completion, and recovery techniques, requiring adjustments to the USGS estimates, as well as the inclusion of shale gas and tight oil resources not yet assessed by USGS. When USGS assessments and underlying data become publicly available, the USGS assumptions for land area, well spacing, and percentage of area with potential typically are used by EIA to develop the AEO TRR estimates. EIA may revise the well spacing assumptions in future AEOs to reflect evolving drilling practices. 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 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 areal extent of formations and the number of layers that could be drilled within formations. Two alternative resource cases are discussed at the end of this chapter.

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 projects which are economically viable are developed subject to the availability of resource development constraints which simulate the existing and expected infrastructure of the oil and 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. CO_2 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 concerns the tax treatment. Tax provisions vary with the type of producer (major, large independent, or small independent). For AEO2013, 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.

Technology advances, including improved drilling and completion practices, as well as advanced production and processing operations, are explicitly modeled to determine the direct impacts on supply, reserves, and various economic parameters. The success of the technology program is measured by estimating the probability that the technology development program will be successfully completed. It reflects the pace at which technology performance improves and the probability that the technology project will meet the program goals. There are four possible curves which represent the adoption of the technology: convex, concave, sigmoid/logistic and linear. The convex curve corresponds to rapid initial market penetration followed by slow market penetration. The concave curve corresponds to slow initial market penetration followed by rapid market penetration. The sigmoid/logistic curve represents a slow initial adoption rate followed by rapid increase in adoption and then slow adoption again as the market becomes saturated. The linear curve represents a constant rate of market penetration, and may be used when no other predictions can be made.

Table 9.3. U.S. unproved technically recoverable tight/shale oil and gas resources by play (as of January 1, 2011)

Region	Basin	Play	Area (mi^2)	Well Spacing ($wells/mi^2$)	% of Area Untested[1]	% of Area with Potential[2]	Average EUR: Crude Oil (MMbls/well)	Average EUR: Natural Gas (Bcf/well)	TRR: Crude Oil (MMbls)	TRR: Natural Gas (Bcf)
Tight/Shale Oil										
1-Northeast	Appalachian	Utica Oil-Core	3,400	2.6	100.0%	80.0%	0.086	0.086	599	599
1-Northeast	Appalachian	Utica Oil-Extension	19,492	2.6	100.0%	20.0%	0.034	0.034	339	339
2-Gulf Coast	Western Gulf	Austin Chalk-Giddings	4,685	8.0	99.1%	52.9%	0.084	0.108	1,644	2,114
2-Gulf Coast	Western Gulf	Austin Chalk-Outlying	14,079	7.7	99.1%	52.8%	0.101	0.312	5,755	17,741
2-Gulf Coast	Western Gulf	Eagle Ford-Oil	5,046	5.4	90.9%	81.4%	0.258	0.293	5,177	5,876
3-Midcontinent	Anadarko	Cana Woodford-Oil	3,957	5.1	100.0%	85.5%	0.024	0.170	414	2,915
4-Southwest	Permian	Bone Spring	2,332	4.0	96.2%	88.0%	0.253	0.234	1,999	1,844
4-Southwest	Permian	Spraberry	1,091	6.4	99.9%	67.8%	0.278	0.650	1,310	3,065
4-Southwest	Permian	Wolfcamp	9,270	4.0	99.1%	34.5%	0.153	0.201	1,941	2,549
5-Rocky Mounttain	Denver	Niobrara	7,724	5.0	100.0%	97.2%	0.012	0.073	440	2,728
5-Rocky Mounttain	Greater Green River	All Plays	1,361	5.8	100.0%	100.0%	0.112	0.015	888	116
5-Rocky Mounttain	Montana Thrust Belt	All Plays	2,400	2.3	100.0%	100.0%	0.111	0.075	602	410
5-Rocky Mounttain	Paradox	Fractured Interbed	2,771	1.6	100.0%	42.3%	0.543	0.434	1,001	801
5-Rocky Mounttain	Powder River	All Plays	19,684	3.0	100.0%	100.0%	0.035	0.040	2,062	2,364
5-Rocky Mounttain	Southwestern Wyoming	All Plays	1,661	5.8	100.0%	100.0%	0.111	0.015	1,084	142
5-Rocky Mounttain	Uinta-Piceance	All Plays	85	16.0	100.0%	100.0%	0.050	0.111	68	152
5-Rocky Mounttain	Williston	Bakken MT	15,790	3.9	97%	27.3%	0.093	0.064	1,519	1,049
5-Rocky Mounttain	Williston	Bakken ND Core	4,012	2.0	75.8%	85.0%	0.372	0.132	1,925	681
5-Rocky Mounttain	Williston	Bakken ND Extension	26,080	2.0	91.5%	45.5%	0.211	0.244	4,593	5,308
6-West Coast	San Joaquin/Los Angeles	Monterey/Santos	1,770	16.0	100.0%	97.3%	0.497	0.553	13,709	15,244
								Tight/Shale Oil Total	**47,067**	**66,037**
Shale Gas										
1-Northeast	Appalachian	Devonian Big Sandy	10,669	6.0	82.3%	20.0%	0.000	0.498	--	5,231
1-Northeast	Appalachian	Devonian Greater Siltstone Area	22,914	6.0	95.5%	20.0%	0.000	0.330	--	8,620
1-Northeast	Appalachian	Devonian Low Thermal Maturity	45,844	6.0	98.7%	10.0%	0.000	0.500	--	13,545
1-Northeast	Appalachian	Marcellus Foldbelt	19,064	4.3	100.0%	4.6%	0.000	0.205	--	774
1-Northeast	Appalachian	Marcellus Interior	45,161	4.3	98.2%	37.0%	0.013	2.065	898	145,645
1-Northeast	Appalachian	Marcellus Western	39,843	5.5	99.5%	7.2%	0.000	0.127	--	1,991
1-Northeast	Appalachian	Utica Gas	49,725	4.3	100.0%	51.8%	0.000	0.339	--	37,257
1-Northeast	Cincinatti Arch	Northwestern Ohio	6,000	4.0	100.0%	50.0%	0.000	0.220	--	2,641
1-Northeast	Illinois	New Albany	1,600	8.0	99.0%	50.0%	0.000	1.722	--	10,909
1-Northeast	Michigan	Antrim	12,000	8.0	91.2%	60.0%	0.000	0.240	--	12,586
2-Gulf Coast	Black Warrior	Floyd-Neal/Conasauga	2,429	2.0	100.0%	65.0%	0.000	1.559	--	4,922
2-Gulf Coast	Louisiana-Mississippi Salt	Haynesville/Bossier	9,320	6.2	94.4%	32.7%	0.001	4.160	16	74,661
2-Gulf Coast	Western Gulf	Pearsall	1,420	6.0	99.9%	85.0%	0.000	1.200	--	8,652
2-Gulf Coast	Western Gulf	Eagle Ford-Dry Gas	2,200	6.0	99.4%	45.0%	0.087	1.946	514	11,456
2-Gulf Coast	Western Gulf	Eagle Ford-Wet Gas	5,400	6.0	99.5%	80.0%	0.196	1.695	5,046	43,583
3-Midcontinent	Anadarko	Cana Woodford-Dry	1,720	4.0	98.0%	52.8%	0.019	2.492	66	8,870
3-Midcontinent	Anadarko	Cana Woodford-Wet	1,590	4.0	97.5%	66.7%	0.291	2.488	1,204	10,297
3-Midcontinent	Arkoma	Caney	2,890	4.0	99.9%	29.1%	0.000	0.337	--	1,132
3-Midcontinent	Arkoma	Fayetteville-Central	3,451	8.0	85.0%	21.9%	0.000	2.155	--	11,075
3-Midcontinent	Arkoma	Fayetteville-West	2,402	8.0	99.7%	25.4%	0.000	0.928	--	4,517
3-Midcontinent	Arkoma	Woodford	3,000	8.0	94.2%	23.2%	0.011	2.868	60	15,043
3-Midcontinent	Black Warrior	Chattanooga	696	8.0	100.0%	29.4%	0.000	0.990	--	1,620
4-Southwest	Fort Worth	Barnett	9,895	8.0	50.0%	46.9%	0.011	1.588	211	29,454
4-Southwest	Permian	Barnett-Woodford	2,691	4.0	99.8%	95.0%	0.000	2.769	--	28,259
5-Rocky Mountain	Greater Green River	Hillard-Baxter-Mancos	17,911	8.0	99.9%	25.0%	0.000	0.372	--	13,302
5-Rocky Mountain	San Juan	Lewis	1,557	3.0	99.9%	95.0%	0.000	2.202	--	9,778
5-Rocky Mountain	Uinta-Piceance	IMancos	3,880	8.0	99.7%	40.0%	0.000	0.903	--	11,288
5-Rocky Mountain	Williston	Gammon	4,207	2.0	100.0%	91.2%	0.000	0.455	--	3,491
6-West Coast	Columbia	Basin Central	1,245	8.0	100.0%	87.7%	0.000	1.400	--	12,220
								Shale Gas Total	**8,085**	**542,821**
Tight Gas										
1-Northeast	Appalachian	Clinton Medina	42,054	10.4	9.3%	63.9%	0.000	0.059	--	12,421
1-Northeast	Appalachian	Tuscarora	42,495	8.0	100.0%	0.6%	0.000	0.686	--	1,399
1-Northeast	Appalachian	Upper Devonian High	12,775	10.0	57.8%	67.1%	0.000	0.212	--	10,514
1-Northeast	Appalachian	Upper Devonian Moderate/Low	29,808	10.0	81.5%	37.0%	0.000	0.061	--	5,510
1-Northeast	Michigan	Berea Sandstone	51,863	8.0	98.2%	18.0%	0.000	0.011	33	799
2-Gulf Coast	Louisiana-Mississippi Salt	Cotton Valley/Bossier	14,794	12.1	90.2%	29.4%	0.016	2.892	755	136,843
2-Gulf Coast	Western Gulf	Olmos	8,233	4.0	91.6%	56.3%	0.020	1.923	347	32,652
2-Gulf Coast	Western Gulf	Vicksburg	3,667	8.0	91.6%	10.7%	0.030	1.474	88	4,238
2-Gulf Coast	Western Gulf	Wilcox Lobo	2,982	8.0	72.0%	41.2%	0.006	1.022	42	7,232

Table 9.3. U.S. unproved technically recoverable tight/shale oil and gas resources by play (as of January 1, 2011) (cont.)

							Average EUR		TRR	
Region	Basin	Play	Area (mi^2)	Well Spacing ($wells/mi^2$)	% of Area Untested[1]	% of Area with Potential[2]	Crude Oil (MMbls/well)	Natural Gas (Bcf/well)	Crude Oil (MMbls)	Natural Gas (Bcf)
Tight Gas										
1-Northeast	Appalachian	Clinton Medina	42,054	10.4	9.3%	63.9%	0.000	0.059	--	12,421
1-Northeast	Appalachian	Tuscarora	42,495	8.0	100.0%	0.6%	0.000	0.686	--	1,399
1-Northeast	Appalachian	Upper Devonian High	12,775	10.0	57.8%	67.1%	0.000	0.212	--	10,514
1-Northeast	Appalachian	Upper Devonian Moderate/Low	29,808	10.0	81.5%	37.0%	0.000	0.061	--	5,510
1-Northeast	Michigan	Berea Sandstone	51,863	8.0	98.2%	18.0%	0.000	0.011	33	799
2-Gulf Coast	Louisiana-Mississippi Salt	Cotton Valley/Bossier	14,794	12.1	90.2%	29.4%	0.016	2.892	755	136,843
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2-Gulf Coast	Western Gulf	Vicksburg	3,667	8.0	91.6%	10.7%	0.030	1.474	88	4,238
2-Gulf Coast	Western Gulf	Wilcox Lobo	2,982	8.0	72.0%	41.2%	0.006	1.022	42	7,232
3-Midcontinent	Anadarko	Cherokee/Redfork	1,978	4.0	72.5%	29.9%	0.009	0.920	16	1,577
3-Midcontinent	Anadarko	Cleveland	2,562	4.0	97.1%	45.1%	0.043	0.892	192	4,003
3-Midcontinent	Anadarko	Granite Wash/Atoka	7,790	4.0	96.1%	28.2%	0.075	1.679	635	14,182
3-Midcontinent	Arkoma	Arkoma	1,000	8.0	69.3%	32.2%	0.000	1.297	--	2,317
4-Southwest	Permian	Abo	1,578	8.0	56.9%	78.9%	0.037	0.713	400	4,038
4-Southwest	Permian	Canyon	9,602	8.0	60.3%	75.2%	0.007	0.228	368	7,938
5-Rocky Mountain	Denver	Denver/jules	4,500	16.0	87.8%	86.1%	0.000	0.244	--	13,254
5-Rocky Mountain	North Central Montana	High Potential	2,000	4.0	77.0%	88.9%	0.000	0.612	--	3,350
5-Rocky Mountain	North Central Montana	Low Potential	3,000	4.0	99.3%	74.7%	0.000	0.212	--	1,889
5-Rocky Mountain	North Central Montana	Moderate Potential	2,000	4.0	97.5%	79.3%	0.000	0.335	--	2,075
5-Rocky Mountain	Piceance	South Basin Williams Fork/ Mesaverde	272	32.0	98.6%	83.7%	0.000	1.091	--	7,849
5-Rocky Mountain	San Juan	Dakota	3,918	8.0	74.9%	99.1%	0.002	0.300	41	6,980
5-Rocky Mountain	San Juan	Mesaverde	3,689	8.0	71.2%	47.4%	0.003	0.345	26	3,432
5-Rocky Mountain	San Juan	Pictured Cliffs	3,958	4.0	67.8%	0.7%	0.000	0.203	--	15
5-Rocky Mountain	Southwestern Wyoming	Deep Mesaverde	16,416	4.0	99.8%	10.9%	0.000	0.414	--	2,955
5-Rocky Mountain	Southwestern Wyoming	Fort Union/Fox Hills	3,858	8.0	99.9%	4.9%	0.000	0.702	--	1,060
5-Rocky Mountain	Southwestern Wyoming	Frontier (Deep)	16,619	4.0	100.0%	6.7%	0.000	2.581	--	10,803
5-Rocky Mountain	Southwestern Wyoming	Frontier Moxa Arch	2,334	8.0	84.2%	15.5%	0.000	1.198	--	2,920
5-Rocky Mountain	Southwestern Wyoming	Lance	5,500	8.0	90.7%	8.6%	0.000	6.605	--	22,675
5-Rocky Mountain	Southwestern Wyoming	Lewis	5.172	8.0	99.2%	36.8%	0.003	0.460	42	6,955
5-Rocky Mountain	Southwestern Wyoming	Shallow Mesaverde (1)	5,239	4.0	95.0%	50.1%	0.000	1.250	--	12,472
5-Rocky Mountain	Southwestern Wyoming	Shallow Mesaverde (2)	6,814	8.0	100.0%	49.0%	0.000	0.671	--	17,914
5-Rocky Mountain	Uinta-Piceance	Basin Flank Mesaverde	1,708	8.0	99.8%	42.8%	0.000	0.988	--	5,767
5-Rocky Mountain	Uinta-Piceance	Deep Synclinal Mesaverde	2,893	8.0	100.0%	14.4%	0.000	0.989	--	3,297
5-Rocky Mountain	Uinta-Piceance	Iles/Mesaverde	1,172	8.0	99.1%	94.3%	0.000	0.730	--	6,395
5-Rocky Mountain	Uinta-Piceance	North Basin Williams Fork/ Mesaverde	908	8.0	100.0%	90.2%	0.000	0.654	--	4,286
5-Rocky Mountain	Uinta-Piceance	South Basin Williams Fork/ Mesaverde	636	32.0	98.6%	83.7%	0.000	0.467	--	7,834
5-Rocky Mountain	Uinta-Piceance	Tertiary East	1,600	16.0	96.4%	32.9%	0.000	0.578	--	4,693
5-Rocky Mountain	Uinta-Piceance	Tertiary West	1,603	8.0	100.0%	21.0%	0.000	4.066	--	10,949
5-Rocky Mountain	Wind River	Fort Union/Lance Deep	2,500	4.0	99.9%	79.6%	0.000	0.537	--	4,267
5-Rocky Mountain	Wind River	Fort Union/Lance Shallow	1,500	8.0	99.5%	94.8%	0.000	1.167	--	13,212
5-Rocky Mountain	Wind River	Mesaverde/Frontier Deep	250	4.0	97.7%	45.0%	0.000	1.992	--	876
5-Rocky Mountain	Wind River	Mesaverde/Frontier Shallow	250	4.0	90.6%	91.6%	0.000	1.252	--	1,039
6-West Coast	Columbia	Basin Centered	1,500	8.0	100.0%	49.9%	0.000	1.257	--	7,528
								Tight Gas Total	**2,985**	**435,405**
								Grand Total	**58,066**	**1,044,263**

EUR = estimated ultimate recovery; TRR = technically recoverable resource.

[1] Percent of total wells (area times well spacing) left to be drilled.

[2] Percent of area that is expected to have technically recoverable resources.

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

Table 9.4. U.S. unproved technically recoverable coalbed methane resources by play (as of January 1, 2011)

Region	Basin	Play	Area (mi^2)	Well Spacing ($wells/mi^2$)	% of Area Untested[1]	% of Area with Potential[2]	Average EUR: Crude Oil (MMbls/ well)	Average EUR: Naturall Gas (Bcf/well)	TRR: Crude Oil (MMbls)	TRR: Natural Gas (Bcf)
1-Northwest	Appalachian	Central Basin	3,870	8	97.8%	34.0%	0	0.176	0	1,812
1-Northwest	Appalachian	North High	3,817	12	100.0%	9.4%	0	0.125	0	540
1-Northwest	Appalachian	North Mod/Low	8,906	12	100.0%	5.5%	0	0.080	0	474
1-Northwest	Illinois	Central Basin	1,714	8	100.0%	74.5%	0	0.120	0	1,226
2-Gulf Coast	Black Warrior	Extention Area	700	8	99.9%	21.1%	0	0.080	0	95
2-Gulf Coast	Black Warrior	Main Area	1,000	12	71.0%	97.1%	0	0.206	0	1,717
2-Gulf Coast	Cahaba	Cahaba Coal Field	387	8	93.4%	73.1%	0	0.179	0	379
3-Midcontinent	Forest City	Central Basin	23,769	8	100.0%	97.2%	0	0.172	0	31,781
3-Midcontinent	Midcontinent	Arkoma	2,998	8	97.8%	92.7%	0	0.216	0	4,703
3-Midcontinent	Midcontinent	Cherokee	3,550	8	100.0%	96.8%	0	0.065	0	1,798
4-Southwest	Raton	Southern	2,028	8	99.8%	95.1%	0	0.375	0	5,782
5-Rocky Mountain	Greater Green River	Deep	3,600	4	100.0%	45.0%	0	0.600	0	3,886
5-Rocky Mountain	Greater Green River	Shallow	720	8	99.7%	89.7%	0	0.204	0	1,052
5-Rocky Mountain	Piceance	Deep	2,000	4	100.0%	76.7%	0	0.600	0	3,680
5-Rocky Mountain	Piceance	Divide Creek	144	8	99.0%	94.9%	0	0.179	0	194
5-Rocky Mountain	Piceance	Shallow	2,000	4	99.2%	94.0%	0	0.299	0	2,234
5-Rocky Mountain	Piceance	White River Dome	216	8	98.7%	94.3%	0	0.410	0	658
5-Rocky Mountain	Powder River	Big George/Lower Fort Union	2,880	16	100.0%	54.5%	0	0.260	0	6,519
5-Rocky Mountain	Powder River	Wasatch	216	8	99.8%	95.3%	0	0.056	0	92
5-Rocky Mountain	Powder River	Wyodak/Upper Fort Union	6,600	20	98.9%	94.4%	0	0.136	0	16,772
5-Rocky Mountain	Raton	Northern	470	8	99.7%	73.2%	0	0.350	0	959
5-Rocky Mountain	Raton	Purgatoire River	360	8	97.2%	49.6%	0	0.311	0	431
5-Rocky Mountain	San Juan	Fairway NM	670	4	50.0%	50.5%	0	1,142	0	773
5-Rocky Mountain	San Juan	North Basin	2,060	4	83.8%	78.4%	0	0,280	0	1,513
5-Rocky Mountain	San Juan	North Basin CO	1,980	4	86.2%	98.0%	0	1,515	0	10,134
5-Rocky Mountain	San Juan	South Basin	1,190	4	93.8%	92.3%	0	0,199	0	821
5-Rocky Mountain	San Juan	South Menefee NM	7,454	5	100.0%	5.0%	0	0.095	0	294
5-Rocky Mountain	Uinta	Blackhawk	1,186	8	99.6%	97.1%	0	0.155	0	1,426
5-Rocky Mountain	Uinta	Ferron	400	8	96.9%	58.6%	0	0.776	0	1,410
5-Rocky Mountain	Uinta	Sego	534	4	99.9%	63.9%	0	0.306	0	418
5-Rocky Mountain	Wind River	Mesaverde	418	2	100.0%	100.0%	0	2,051	0	1,713
5-Rocky Mountain	Wyoming Thrust Belt		5,200	2	100.0%	100.0%	0	0.454	0	5,418
6-West Coast	Western Washington	Bellingham	441	2	100.0%	100.0%	0	2,391	0	2,109
6-West Coast	Western Washington	Southern Puget Lowlands	1,102	2	100.0%	100.0%	0	0.687	0	1,514
6-West Coast	Western Washington	Western Cascade Mountains	2,174	2	100.0%	99.0%	0	1.559	0	6,710
								Total Coalbed Methane	**0**	**120,944**

EUR = estimated ultimate recovery; TRR = technically recoverable resource.
[1] Percent of total wells (area times well spacing) left to be drilled.
[2] Percent of area that is expected to have technically recoverable resources.
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Table 9.5. Distribution of EURs in the Bakken

	Number of Potential Wells	EUR (mbbls/well), Well Category: Top 15%	Middle 70%	Bottom 15%	Average EUR
Bakken MT	16,324	154	87	18	93
Bakken ND Core	5,157	765	349	89	372
Bakken ND Extension	21,767	476	189	48	211

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

The market penetration curve is a function of the relative economic attractiveness of the technology instead of being a time-dependent function. A technology will not be implemented unless the benefits through increased production or cost reductions are greater than the cost to apply the technology. As a result, the market penetration curve provides a limiting value on commercialization instead of a specific penetration path. In addition to the curve, the implementation probability captures the fact that not all technologies that have been proven in the lab are able to be successfully implemented in the field.

CO_2 enhanced oil recovery

For CO_2 miscible flooding, the OLOGSS incorporates both industrial and natural sources of CO_2. The industrial sources of CO_2 are:

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

Technology and market constraints prevent the total volumes of CO_2 (Table 9.6) from becoming immediately available. The development of the CO_2 market is divided into 2 periods: 1) development phase and 2) market acceptance phase. During the development phase, the required capture equipment is developed, pipelines and compressors are constructed, and no CO_2 is available. During the market acceptance phase, the capture technology is being widely implemented and volumes of CO_2 first become available. The number of years in each development period is shown in Table 9.7. CO_2 is available from planned Carbon Sequestration and Storage (CCS) power plants funded by American Recovery and Reinvestment Act of 2009 (ARRA) starting in 2016.

Table 9.6. Maximum volume of CO_2 available

OGSM Region	Natural	Hydrogen	Ammonia	Ethanol	Cement	Refineries (hydrogen)	Power Plants	Natural Gas Processing
East Coast	0	3	0	52	94	17	12980	23
Gulf Coast	292	0	78	0	86	114	3930	114
Midcontinent	16	0	0	175	48	1	752	0
southwest	657	0	0	68	74	0	0	0
Rocky Mountains	80	0	3	23	35	62	2907	12
West Coast	0	0	0	4	48	93	1134	40
Northern Great Plains	0	0	0	9	3	16	60	6

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

The cost of CO_2 from natural sources is a function of the oil price. For industrial sources of CO_2, the cost to the producer includes the cost to capture, compress to pipeline pressure, and transport to the project site via pipeline within the region (Table 9.8). Inter-regional transportation costs add $0.40 per Mcf for every region crossed.

Lower 48 offshore

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

For currently producing fields, a 20-percent exponential decline is assumed for production except for natural gas production from fields in shallow water, which uses a 30-percent exponential decline. Fields that began production after 2008 are assumed to remain at their peak production level for 2 years before declining.

Table 9.7. CO_2 availability assumptions

Source Type	Development Phase (years)	Market Acceptance Phase (years)	Ultimate Market Acceptance
Natural	1	10	100%
Hydrogen	4	10	100%
Ammonia	2	10	100%
Ethanol	4	10	100%
Cement	7	10	100%
Refineries (hydrogen)	4	10	100%
Power Plants	12	10	100%
Natural Gas Processing	2	10	100%

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

Table 9.8. Industrial CO_2 capture & transportation costs by region
$/Mcf

OGSM Region	Hydrogen	Ammonia	Ethanol	Cement	Refineries (hydrogen)	Power Plants	Natural Gas Processing	CBTL
East Coast	$2.44	$2.10	$2.23	$4.29	$2.44	$5.96	$1.92	$1.91
Gulf Coast	$1.94	$2.10	$2.23	$4.29	$1.94	$5.96	$1.92	$1.91
Midcontinent	$2.07	$2.10	$2.23	$4.29	$2.07	$5.96	$1.92	$1.91
Southwest	$2.02	$2.10	$2.23	$4.29	$2.02	$5.96	$1.92	$1.91
Rocky Mountains	$2.03	$2.10	$2.23	$4.29	$2.03	$5.96	$1.92	$1.91
West Coast	$2.01	$2.10	$2.23	$4.29	$2.01	$5.96	$1.92	$1.91
Northern Great Plains	$2.05	$2.10	$2.23	$4.29	$2.05	$5.96	$1.92	$1.91

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

The assumed field size and year of initial production of the major announced deepwater discoveries that were not brought into production by 2011 are shown in Table 9.9. A field that is announced as an oil field is assumed to be 100 percent oil and a field that is announced as a gas field is assumed to be 100 percent gas. If a field is expected to produce both oil and gas, 70 percent is assumed to be oil and 30 percent is assumed to be gas.

Production is assumed to:

- ramp up to a peak level in 2 to 4 years depending on the size of the field,
- remain at the peak level until the ratio of cumulative production to initial resource reaches 20 percent for oil and 30 percent for natural gas,
- and then decline at an exponential rate of 20-30 percent.

The discovery of new fields (based on BOEM'S 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 in the previous paragraph). Advances in technology for the various activities associated with crude oil and natural gas exploration, development, and production can have a profound impact on the costs associated with these activities. The specific technology levers and values for the offshore are presented in Table 9.10.

Leasing is assumed to be available 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.

Alaska crude oil production

Projected Alaska oil production includes both existing producing fields and undiscovered fields that are expected to exist, based upon 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 in 2016. Alaska 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 and operating costs, and on the 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.

Table 9.9. 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
Anduin West	MC754	2,696	2008	11	46	2012
Bushwood	GB463	2,700	2009	13	182	2012
Caesar	GC683	4,457	2006	11	45	2012
Cascade	WR206	8,143	2002	14	372	2012
Cheyenne East	LL400	9,200	2010	9	12	2012
Chinook	WR469	8,831	2003	14	372	2012
Clipper	GC299	3,452	2005	11	45	2012
Galapogos	MC519	6,526	2009	11	45	2012
Goose	MC751	1,624	2003	11	45	2012
Isabella	MC562	6,535	2007	11	45	2012
Mandy	MC199	2,478	2010	13	182	2012
MC241	MC285	2,427	2006	11	45	2012
Ozona	GB515	3,000	2008	11	45	2012
Pyrenees	GB293	2,100	2009	12	89	2012
Silvertip	AC815	9,226	2004	12	372	2012
West Tonga	GC726	4,674	2007	12	89	2012
Wide Berth	GC490	3,700	2009	12	89	2012
Axe	DC004	5,831	2010	12	89	2013
Big Foot	WR029	5,235	2005	12	89	2013
Dalmatian	DC048	5,876	2008	12	89	2013
Knotty Head	GC512	3,557	2005	14	372	2013
Jack	WR759	6,963	2004	14	372	2014
Lucius	KC875	7,168	2009	13	182	2014
St. Malo	WR678	7,036	2003	14	372	2014
Tubular Bells	MC725	4,334	2003	12	89	2014
Freedom	MC948	6,095	2008	15	691	2015
Heidelberg	GC859	5,000	2009	13	182	2015
Kodiak	MC771	4,986	2008	13	182	2015
Pony	GC468	3,497	2006	14	372	2015
Samurai	GC432	3,400	2009	12	89	2015
Winter	GB605	3,400	2009	11	45	2015
Kaskida	KC292	5,860	2006	15	691	2016
Mission Deep	GC955	7,300	1999	13	182	2016
Stones	WR508	9,556	2005	12	89	2016
Tiber	KC102	4,132	2009	15	691	2016
Vito	MC984	4,038	2009	13	182	2016
Shenandoah	WR052	5,750	2009	13	182	2017

Table 9.9. 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
Buckskin	KC872	6,920	2009	13	182	2018
Diamond	LL370	9,975	2008	11	45	2018
Julia	WR627	7,087	2007	12	89	2018
Appomattox	MC392	7,217	2009	15	691	2019
Hadrian South	KC964	7,586	2009	13	182	2019
Hal	WR848	7,657	2008	11	45	2019
Vicksburg	DC353	7,457	2009	14	372	2019
Cardamom	GB427	2,720	2010	13	182	2020
Hadrian North	KC919	7,000	2010	14	372	2020

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

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 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 West Texas Intermediate crude oil prices. In contrast, South- Central wildcat well drilling rates were found to be uncorrelated to crude oil prices or any other criterion. However, South- Central wildcat well drilling rates on average equaled just over 3 wells per year during the 1977 through 2008 period, so 3 South- Central wildcat exploration wells are assumed to be drilled every year in the future.

Table 9.10. Offshore exploration and production technology levels

Technology Level	Total Improvement over 30 years (percent)
Exploration success rates	30
Delay to commence first exploration and between	15
Exploration & 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.

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. However, over time, the offshore proportion increases linearly, so that after 20 years, 50 percent of the North Slope wildcat wells are drilled onshore and 50 percent are drilled offshore. The 50/50 onshore/offshore wildcat well apportionment remains constant through the remainder of the projection in recognition of the fact that 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 for the onshore and State offshore regions of Alaska, and by the Bureau of Ocean Energy Management (BOEM) (formerly known as the U.S. Minerals Management Service) for the Federal offshore regions of Alaska. It is assumed that the largest undiscovered oil fields will be found and developed first and in preference to the small and midsize undiscovered fields. As the exploration and discovery process proceeds 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 and that the largest fields enjoy economies of scale, which ake them more profitable and less risky to develop than the smaller fields.

Oil and gas exploration and production currently are not permitted in the Arctic National Wildlife Refuge. The projections for Alaska oil and gas production assume that this prohibition remains in effect throughout the projection period.

Three uncertainties are associated with the Alaska oil projections. First, whether the heavy oil deposits located on the North Slope, which exceed 20 billion barrels of oil-in-place, will be producible in the foreseeable future at recovery rates exceeding a few percent. Second, the oil production potential of the North Slope shale formations is unknown at this time. Third, 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.[6] Although the onset of TAPS low flow problems could begin at around 550,000 barrels per day, absent any mitigation, the severity of the TAPS operational problems is expected to increase significantly as throughput declines. As the types and severity of problems multiplies, 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 barrels per day of throughput, considerable investment might be required to keep the pipeline operational below this threshold. Thus, North Slope fields are assumed to be shut down, plugged, and abandoned when the following 2 conditions are simultaneously satisfied: 1) TAPS throughput would have to be at or below 350,000 barrels per day and 2) total North Slope oil production revenues would have to be at or below $5.0 billion per year.

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 5 years following its November 28, 1995 enactment. The volume of production on which no royalties were due for the 5 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. In the model it is assumed that relief will be granted at roughly the same levels as provided during the first 5 years of the act.

Section 345 of the Energy Policy Act of 2005 provides royalty relief for oil and gas production in water depths greater than 400 meters in the Gulf of Mexico from any oil or gas lease sale occurring within 5 years after enactment. The minimum volumes of production with suspended royalty payments are:

(1) 5,000,000 barrels of oil equivalent (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; and

(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 roduction 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 gas from the completed deep well must begin before 5 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) 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 yet 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.

Oil and gas supply alternative cases

Tight Oil and Shale Gas Resource 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 last 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 over 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. Additionally, technological improvements and innovations may allow development of crude oil and natural gas resources that have not been identified yet so are not included in the Reference case.

Two cases were developed with alternate crude oil and natural gas resource assumptions. These cases do not represent an upper and lower bound on future domestic oil and natural gas supply but rather provide a framework to examine the impact of higher and lower domestic supply on energy demand, imports, and prices (see ‘Issues in Focus’ articles).

High Oil and Gas Resource case. This case is designed to address what might happen if domestic crude oil production continued to increase through the projection period, reaching over 10 million barrels per day. This case includes (1) 100 percent higher estimated ultimate recovery (EUR) per tight oil, tight gas, and shale gas well than in the reference case and a maximum well spacing of 40 acres to reflect the possibility that additional layers of low permeability zones are identified and developed, compared with well spacing that ranges from 20 to 406 acres with an average of 100 acres in the Reference case; (2) kerogen development reaching 135,000 barrels per day by 2025; (3) tight oil development in Alaska increasing the total Alaska TRR by 1.9 billion barrels; and (4) 50 percent higher technically recoverable undiscovered resources in Alaska and the offshore lower 48 states than in the Reference case. A few offshore Alaska fields are assumed to be discovered and thus developed earlier than in the Reference case. The total unproved technically recoverable resources are 557 billion barrels of crude oil and 6,771 trillion cubic feet compared to 197 billion barrels of crude oil and 2,022 trillion cubic feet of dry natural gas in the Reference case. Proved reserves of oil and natural gas are the same in all three cases; 25 billion barrels of crude oil and 305 trillion cubic feet of dry natural gas. Additionally, given the higher natural gas resource in this case, the maximum penetration rate for gas-to-liquids (GTL) was increased to 10 percent per year from a nominal rate of 5 percent per year in the Reference case.

Low Oil and Gas Resource case. In this case, the EUR per tight oil, tight gas, and shale gas well is assumed to be 50 percent lower than in the Reference case, increasing the per-unit cost of developing the resource. The total unproved technically recoverable crude oil resource is decreased to 168 billion barrels and the natural gas resource is decreased to 1500 trillion cubic feet, compared to 197 billion barrels of crude oil and 2,022 trillion cubic feet of natural gas assumed in the Reference case.

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 prior to 2040.

[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 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 and undiscovered resources, which are located outside oil and 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] Donald L. Gautier and others, U.S. Department of the Interior, U.S. Geological Survey, 1995 National Assessment of the United States Oil and Gas Resources, (Washington, D.C., 1995); U.S. Department of the Interior, Minerals Management Service, Report to Congress: Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources, (February 2006); and 2003 estimates of conventionally recoverable hydrocarbon resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 2003.

[6] Alyeska Pipeline Service Company, Low Flow Impact Study, Final Report, June 15, 2011, Anchorage, Alaska, at www.alyeska-pipe.com/Inthenews/LowFlow/LoFIS_Summary_Report_P6%2027_FullReport.pdf