Oil and Gas Supply Module

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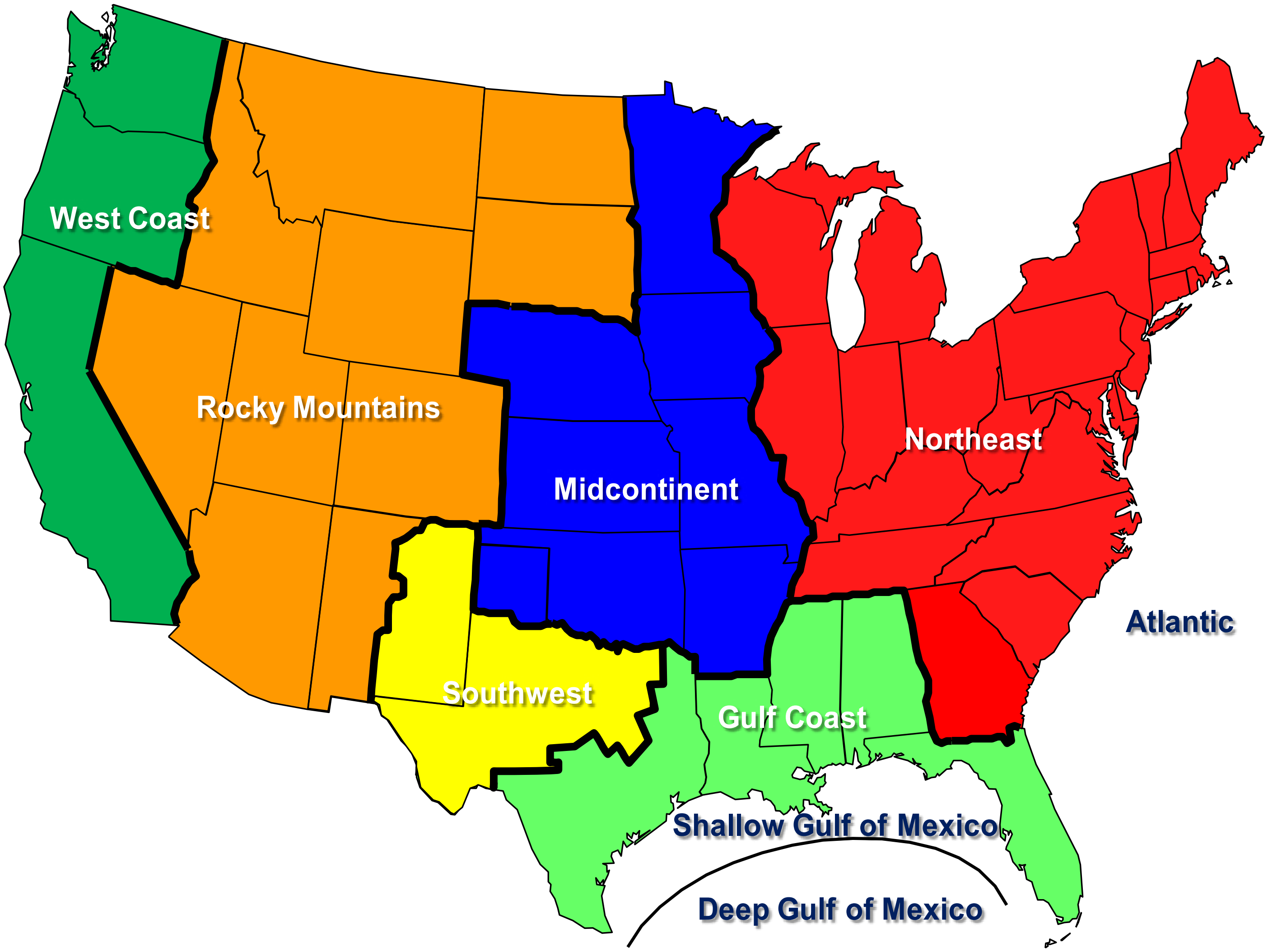
The NEMS Oil and Gas Supply Module (OGSM) constitutes a comprehensive framework with which to analyze crude oil and natural gas exploration and development on a regional basis (Figure 8). The OGSM is organized into 4 submodules: Onshore Lower 48 Oil and Gas Supply Submodule, Offshore Oil and Gas Supply 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 continuity, as well as enhanced oil recovery processes such as CO_2 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

Domestic oil and natural gas technically recoverable resources [2] consist of proved reserves [3] and unproved resources [4]. OGSM resource assumptions are based on estimates of technically recoverable resources from the United States Geological Survey (USGS) and the Bureau of Ocean Energy Management (BOEM) of the Department of the Interior [5]. Supplemental adjustments to the USGS continuous crude oil and natural gas resources are made to incorporate the latest available production data and to add some frontier plays that are not quantitatively assessed by the USGS. While undiscovered resources for Alaska are based on USGS estimates, estimates of recoverable resources are obtained on a field-by-field basis from a variety of sources including trade press. Published estimates in Tables 9.1 and 9.2 reflect the removal of intervening reserve additions between the date of the latest available assessment and January 1, 2010.

Table 9.1. Technically recoverable U.S. crude oil resources as of January 1, 2010
billion barrels

	Proved Reserves	Unproved Resources	Total Technically Recoverable Resources
Lower 48 Onshore	14.2	112.6	126.7
Northeast	0.2	4.4	4.6
Gulf Coast	1.5	21.4	22.8
Midcontinent	1.3	12.7	14.0
Southwest	5.3	27.6	32.9
Rocky Mountain	3.2	23.0	26.2
West Coast	2.7	23.5	26.2
Lower 48 Offshore	4.6	50.3	54.8
Gulf (currently available)	4.1	38.7	42.7
Eastern/Central Gulf (unavailable until 2022)	0.0	3.7	3.7
Pacific	0.5	6.6	7.1
Atlantic	0.0	1.4	1.4
Alaska (Onshore and Offshore)	3.6	35.0	38.6
Total U.S.	22.3	197.9	220.2

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 2035.
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, 2010.

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 play-level unproved technically recoverable resource assumptions for tight oil, shale gas, tight gas, and coalbed methane are shown in Tables 9.3-9.6. 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 continuity) 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.

Table 9.2. Technically recoverable U.S. natural gas resources as of January 1, 2010
trillion cubic feet

	Proved Reserves	Unproved Resources	Total Technically Recoverable Resources
Lower 48 Onshore Non Associated Natural Gas	230.0	1250.2	1480.3
Tight Gas	87.9	422.7	510.7
Northeast	5.2	51.8	57.0
Gulf Coast	24.3	96.8	121.1
Midcontinent	7.4	22.1	29.5
Southwest	3.4	24.5	27.9
Rocky Mountain	47.6	222.0	267.6
West Coast	0.0	7.5	7.5
Shale Gas	60.6	481.8	542.3
Northeast	7.1	216.5	223.6
Gulf Coast	10.9	129.7	140.6
Midcontinent	15.4	39.8	55.2
Southwest	26.5	46.1	72.6
Rocky Mountain	0.7	37.4	38.1
West Coast	0.0	12.2	12.2
Coalbed Methane	18.6	122.2	140.8
Northeast	2.5	4.1	6.5
Gulf Coast	1.3	2.2	3.5
Midcontinent	0.7	38.3	38.9
Southwest	0.5	5.8	6.2
Rocky Mountain	13.6	61.6	75.2
West Coast	0.0	10.3	10.3
Other	63.0	223.5	286.5
Northeast	7.0	29.2	36.2
Gulf Coast	10.9	101.2	112.0
Midcontinent	20.3	26.5	46.8
Southwest	16.9	18.6	35.5
Rocky Mountain	7.3	35.0	42.3
West Coast	0.6	13.1	13.7
Lower 48 Onshore Associated-Dissolved Gas	18.4	146.2	164.6
Northeast	0.4	0.6	0.9
Gulf Coast	1.7	23.9	25.6
Midcontinent	1.7	12.3	14.0
Southwest	8.3	40.4	48.7
Rocky Mountain	4.1	45.9	50.0
West Coast	2.1	23.2	25.3
Lower 48 Offshore	15.0	262.6	277.6
Gulf (currently available)	14.2	218.4	232.5
Eastern/Central Gulf (unavailable until 2022)	0.0	21.5	21.5
Pacific	0.8	10.4	11.2
Atlantic	0.0	12.4	12.4
Alaska (Onshore and Offshore)	9.1	271.7	280.8
Total U.S.	272.5	1930.7	2203.3

Note: Resources in other areas where drilling is officially prohibited are not included. The estimate of 32.9 trillion cubic feet of natural gas resources in the Northern Atlantic, Northern and Central Pacific, and within a 50-mile buffer off the Mid and Southern Atlantic OCS is also excluded from the technically recoverable volumes because leasing is not expected in these areas by 2035.
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, 2010.

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 *AEO2012*, 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.

Table 9.3. U.S. unproved technically recoverable tight oil resources by play - *AEO2012*

Region	Basin	Play	Area (mi^2)	Average Well Spacing ($wells/mi^2$)	% of Area Untested	% of Area with Potential	Average EUR (mmb/well)	TRR (mmb)
2	West Gulf	Austin Chalk	16,078	3	72%	61%	0.13	2,688
2	West Gulf	Eagle Ford Shale	3,200	5	100%	54%	0.28	2,461
3	Anadarko	Woodford Shale	3,120	6	100%	88%	0.02	393
4	Permian	Avalon/Bone Springs Shale	1,313	4	100%	78%	0.39	1,593
4	Permian	Spraberry	1,085	6	99%	72%	0.11	510
5	Rocky Mountain Basins	Niobrara	20,385	8	97%	80%	0.05	6,500
5	Williston	Bakken Shale	6,522	2	77%	97%	0.55	5,372
6	San Joaquin/Los Angeles	Monterey/Santos Shale	2,520	12	98%	93%	0.50	13,709
Total								**33,226**

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

Table 9.4. U.S. unproved technically recoverable shale gas resources by play - *AEO2012*

Region	Basin	Play	Area (mi^2)	Average Well Spacing ($wells/mi^2$)	% of Area Untested	% of Area with Potential	Average EUR (bcf/well)	TRR (bcf)
1	Appalachian	Devonian Big Sandy	10,669	6	82%	20%	0.57	6,020
1	Appalachian	Devonian Greater Sitstone Area	22,914	6	95%	20%	0.33	8,645
1	Appalachian	Devonian Low Thermal Maturity	45,844	6	99%	10%	0.50	13,592
1	Appalachian	Marcellus - KY Western	207	5	100%	7%	0.13	11
1	Appalachian	Marcellus - MD Foldbelt	435	4	100%	5%	0.21	18
1	Appalachian	Marcellus - MD Interior	763	4	100%	37%	0.52	630
1	Appalachian	Marcellus - NY Interior	10,381	4	100%	37%	2.43	40,123
1	Appalachian	Marcellus - NY Western	7,985	5	100%	7%	0.13	425
1	Appalachian	Marcellus - OH Interior	361	4	99%	37%	0.52	296
1	Appalachian	Marcellus - OH Western	13,515	5	100%	7%	0.13	720
1	Appalachian	Marcellus - PA Foldbelt	7,951	4	100%	5%	0.21	323
1	Appalachian	Marcellus - PA Interior	23,346	4	98%	37%	2.43	88,180
1	Appalachian	Marcellus - PA Western	6,582	5	100%	7%	0.13	351
1	Appalachian	Marcellus - TN Foldbelt	353	4	100%	5%	0.21	14
1	Appalachian	Marcellus - VA Foldbelt	7,492	4	100%	5%	0.21	304
1	Appalachian	Marcellus - VA Interior	321	4	100%	37%	0.52	265
1	Appalachian	Marcellus - VA Western	653	5	100%	7%	0.13	35
1	Appalachian	Marcellus - WV Foldbelt	2,833	4	100%	5%	0.21	115
1	Appalachian	Marcellus - WV Interior	9,989	4	99%	37%	0.52	8,186
1	Appalachian	Marcellus - WV Western	10,901	5	98%	7%	0.13	571
1	Appalachian	Northwestern Ohio	6,000	4	100%	50%	0.22	2,643
1	Appalachian	Utica	16,590	4	100%	21%	1.13	15,712
1	Illinois	New Albany	1,600	8	99%	50%	1.72	10,904
1	Michigan	Antrim	12,000	8	91%	60%	0.35	18,411
2	Black Warrior	Floyd-Neal/Conasauga	2,429	2	100%	65%	1.52	4,805
2	TX-LA-MS Salt	Haynesville - LA	3,730	8	96%	49%	3.28	46,102
2	TX-LA-MS Salt	Haynesville - TX	5,590	8	99%	24%	1.87	19,758
2	West Gulf Coast	Eagle Ford - Dry	2,200	6	99%	43%	1.78	10,044
2	West Gulf Coast	Eagle Ford - Wet	5,400	6	99%	49%	2.57	40,175
2	West Gulf Coast	Pearsall	1,420	6	100%	85%	1.22	8,817

Table 9.4. U.S. unproved technically recoverable shale gas resources by play - *AEO2012* (cont.)

Region	Basin	Play	Area (mi²)	Average Well Spacing (wells/mi²)	% of Area Untested	% of Area with Potential	Average EUR (bcf/well)	TRR (bcf)
3	Anadarko	Woodford	3,350	4	99%	29%	2.89	10,981
3	Arkoma	Caney	2,890	4	100%	29%	0.34	1,135
3	Arkoma	Chattanooga	696	8	100%	29%	0.99	1,617
3	Arkoma	Fayetteville - Central	3,451	8	88%	22%	1.71	9,070
3	Arkoma	Fayetteville - West	2,402	8	100%	25%	0.86	4,170
3	Arkoma	Woodford - Western Arkoma	3,000	8	98%	23%	1.97	10,678
3	Southwestern OK	Woodford	1,200	4	99%	20%	2.31	2,189
4	Fort Worth	Barnett	6,458	8	71%	30%	1.69	18,651
4	Permian	Barnett-Woodford	2,691	4	99%	95%	2.70	27,470
5	Greater Green River	Hilliard-Baxter-Mancos	17,911	8	100%	25%	0.37	13,285
5	San Juan	Lewis	1,557	3	100%	95%	2.20	9,760
5	Uinta	Mancos	3,880	8	99%	40%	0.88	10,873
5	Williston	Gammon	4,207	2	100%	91%	0.46	3,491
6	Columbia	Basin-Centered	6,387	8	100%	17%	1.40	12,220
Total								**481,783**

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

Table 9.5. U.S. unproved technically recoverable tight gas resources by play - *AEO2012*

Region	Basin	Play	Area (mi²)	Average Well Spacing (wells/mi²)	% of Area Untested	% of Area with Potential	Average EUR (bcf/well)	TRR (bcf)
1	Appalachian	Berea Sandstone	51,863	8	86%	18%	0.18	11,401
1	Appalachian	Clinton/Medina High	14,773	8	81%	28%	0.25	6,786
1	Appalachian	Clinton/Medina Moderate/Low	27,281	15	86%	59%	0.08	16,136
1	Appalachian	Tuscarora Sandstone	42,495	8	100%	1%	0.69	1,485
1	Appalachian	Upper Devonian High	12,775	10	58%	67%	0.21	10,493
1	Appalachian	Upper Devonian Moderate/Low	29,808	10	82%	37%	0.06	5,492
2	East Texas	Cotton Valley/Bossier	14,794	12	96%	29%	1.39	69,720
2	Texas-Gulf	Olmos	8,233	4	97%	56%	0.44	7,809
2	Texas-Gulf	Vicksburg	3,667	8	93%	11%	2.36	6,929
2	Texas-Gulf	Wilcox/Lobo	2,982	8	79%	41%	1.60	12,373
3	Anadarko	Cherokee/Redfork	1,978	4	58%	30%	0.90	1,220
3	Anadarko	Cleveland	2,562	4	88%	45%	0.91	3,724
3	Anadarko	Granite Wash/Atoka	7,790	4	98%	28%	1.72	14,821
3	Arkoma	Arkoma Basin	1,000	8	69%	32%	1.30	2,315
4	Permian	Abo	1,578	8	91%	99%	1.00	11,386
4	Permian	Canyon	6,602	8	91%	85%	0.22	13,105
5	Denver	Denver/Jules	4,500	16	88%	86%	0.24	13,212
5	Greater Green River	Deep Mesaverde	16,416	4	100%	11%	0.41	2,939
5	Greater Green River	Fort Union/Fox Hills	3,858	8	100%	5%	0.70	1,059
5	Greater Green River	Frontier (Deep)	15,619	4	100%	7%	2.58	10,801
5	Greater Green River	Frontier (Moxa Arch)	2,334	8	89%	16%	1.20	3,076
5	Greater Green River	Lance	5,500	8	100%	9%	6.60	24,951
5	Greater Green River	Lewis	5,172	8	99%	37%	1.32	19,813
5	Greater Green River	Shallow Mesaverde (1)	5,239	4	95%	50%	1.25	12,457
5	Greater Green River	Shallow Mesaverde (2)	6,814	8	100%	49%	0.67	17,874
5	Piceance	Iles/Mesaverde	1,172	8	99%	94%	0.73	6,379
5	Piceance	North Basin Williams Fork/Mesaverde	908	8	100%	90%	0.65	4,278
5	Piceance	South Basin Williams Fork/Mesaverde	908	32	99%	84%	0.65	15,648
5	San Juan	Central Basin/Dakota	3,918	8	88%	99%	0.98	26,663
5	San Juan	Central Basin/Mesaverde	3,689	8	83%	47%	0.82	9,483
5	San Juan	Picture Cliffs	6,558	4	63%	1%	0.48	36

Table 9.5. U.S. unproved technically recoverable tight gas resources by play - *AEO2012* (cont.)

Region	Basin	Play	Area (mi^2)	Average Well Spacing ($wells/mi^2$)	% of Area Untested	% of Area with Potential	Average EUR (bcf/well)	TRR (bcf)
5	Uinta	Basin Flank Mesaverde	1,708	8	100%	43%	0.99	5,767
5	Uinta	Deep Synclinal Mesaverde	2,893	8	100%	14%	0.99	3,292
5	Uinta	Tertiary East	1,600	16	96%	33%	0.58	4,690
5	Uinta	Tertiary West	1,603	8	100%	21%	4.06	10,914
5	Williston	High Potential	2,000	4	77%	89%	0.61	3,343
5	Williston	Low Potential	3,000	4	99%	75%	0.21	1,886
5	Williston	Moderate Potential	2,000	4	98%	79%	0.33	2,071
5	Wind River	Fort Union/Lance Deep	2,500	4	100%	80%	0.54	4,261
5	Wind River	Fort Union/Lance Shallow	1,500	8	100%	95%	1.17	13,197
5	Wind River	Mesaverde/Frontier Deep	250	4	98%	45%	1.99	876
5	Wind River	Mesaverde/Frontier Shallow	250	4	91%	92%	1.25	1,037
6	Columbia	Basin-Centered	1,500	8	100%	50%	1.26	7,521
Total								**422,719**

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

Table 9.6. U.S. unproved technically recoverable coalbed methane resources by play - *AEO2012*

Region	Basin	Play	Area (mi^2)	Average Well Spacing ($wells/mi^2$)	% of Area Untested	% of Area with Potential	Average EUR (bcf/well)	TRR (bcf)
1	Appalachian	Central Basin	3,870	8	98%	34%	0.18	1,835
1	Appalachian	North Appalachian Basin - High	3,817	12	100%	9%	0.12	536
1	Appalachian	North Appalachian Basin - Mod/Low	8,906	12	100%	5%	0.08	469
1	Illinois	Central Basin	1,714	8	100%	75%	0.12	1,224
2	Black Warrior	Extention Area	700	8	100%	21%	0.08	94
2	Black Warrior	Main Area	1,000	12	71%	97%	0.21	1,706
2	Cahaba	Cahaba Coal Field	387	8	93%	73%	0.18	379
3	Midcontinent	Arkoma	2,998	8	98%	93%	0.22	4,692
3	Midcontinent	Cherokee	3,550	8	100%	97%	0.06	1,784
3	Midcontinent	Forest City	36,917	8	100%	63%	0.17	31,781
4	Raton	Southern	2,028	8	100%	95%	0.37	5,770
5	Greater Green River	Deep	3,600	4	100%	45%	0.60	3,879
5	Greater Green River	Shallow	720	8	100%	90%	0.20	1,053
5	Greater Green River	Western Wyoming	15,097	2	100%	52%	0.46	7,131
5	Piceance	Deep	2,000	4	100%	77%	0.60	3,677
5	Piceance	Divide Creek	144	8	99%	95%	0.18	194
5	Piceance	Shallow	2,000	4	99%	94%	0.30	2,230
5	Piceance	White River Dome	216	8	99%	94%	0.41	657
5	Powder River	Big George/Lower Fort Union	2,880	16	100%	55%	0.26	6,507
5	Powder River	Wasatch	216	8	100%	95%	0.06	92
5	Powder River	Wyodak/Upper Fort Union	6,600	20	99%	94%	0.14	16,725
5	Raton	Northern	470	8	100%	73%	0.35	957
5	Raton	Purgatoire River	360	8	97%	50%	0.31	430
5	San Juan	Fairway NM	670	4	84%	30%	1.14	774
5	San Juan	North Basin	2,060	4	84%	78%	0.28	1,511
5	San Juan	North Basin CO	1,980	4	86%	98%	1.51	10,123
5	San Juan	South Basin	1,190	4	94%	92%	0.20	820
5	San Juan	South Menefee NM	7,454	5	100%	5%	0.10	177
5	Uinta	Blackhaw	1,186	8	100%	97%	0.16	1,423
5	Uinta	Ferron	400	8	97%	59%	0.78	1,409
5	Uinta	Sego	534	4	100%	64%	0.31	417
5	Wind River	Mesaverde	3,018	2	100%	13%	1.73	1,387
6	Western Washington	Bellinham/Western Cascade/	3,655	5	100%	60%	0.94	10,339
Total								**122,183**

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

Technology

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.

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. The specific technology levers and assumptions are shown in Table 9.7.

Table 9.7. Onshore lower 48 technology assumptions

	Ultimate Market Penetration	Market Penetration Curve	Probability of Successful R&D	Probability of Implementation	Drilling Success Rate	Exploration Sucess Rate	Injection Rate	Estimated Ultimate Recovery
Conventional Oil								
Infill Drilling	0.59	linear	0.5	0.44	0.03	0.03	--	0.01
Horizonal Continuity	0.6	linear	0.51	0.44	0.03	0.03	0.25	0.023
Horizontal Profile	0.6	concave	0.49	0.45	0.03	0.03	0.02	0.005
CO_2 Flooding	0.61	linear	0.51	0.43	0.03	0.03	0.38	0.042
Steam Flooding	0.6	logistic	0.49	0.44	0.03	0.03	0.01	0.09
Polymer Flooding	0.61	concave	0.5	0.44	0.03	0.03	0.123	0.06
Profile Modification	0.59	concave	0.51	0.42	0.03	0.03	--	0.06
Undiscovered	0.6	concave	0.48	0.44	0.03	0.03	--	0.08
Tight Oil	0.6	concave	0.48	0.44	0.03	0.03	--	0.08
Conventional Gas								
Developing	0.61	linear	0.48	0.46	0.03	0.03	--	0.04
Undiscovered	0.61	linear	0.49	0.45	0.03	0.03	--	0.07
Tight Gas								
Developing	0.61	linear	0.48	0.46	0.03	0.03	--	0.04
Undiscovered	0.61	linear	0.49	0.45	0.03	0.03	--	0.05
Shale Gas								
Developing	0.61	linear	0.48	0.45	0.03	0.03	--	0.08
Undiscovered	0.61	linear	0.48	0.45	0.03	0.03	--	0.7
Coalbed Methane								
Developing	0.6	linear	0.5	0.44	0.03	0.03	--	0.05
Undiscovered	0.6	linear	0.49	0.43	0.03	0.03	--	0.05

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

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 9.8) 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 9.9. CO_2 is available from planned Carbon Sequestion and Storage (CCS) power plants funded by American Recovery and Reinvestment Act of 2009 (ARRA) starting in 2016.

Table 9.8. Maximum volume of CO_2 available

billion cubic feet

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.

Table 9.9. 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.

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 9.10). Inter-regional transportation costs add $0.40 per Mcf for every region crossed.

Table 9.10. 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.

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.

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 9.11. 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 9.12.

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 9.11. 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
Pyrenees	GB293	2100	2009	12	89	2012
Wide Berth	GC490	3700	2009	12	89	2012
West Tonga	GC726	4674	2007	12	89	2012
Bushwood	GB463	2700	2009	13	182	2012
Mandy	MC199	2478	2010	13	182	2012
Cascade	WR206	8143	2002	14	372	2012
Chinook	WR469	8831	2003	14	372	2012
Axe	DC004	5831	2010	12	89	2013
Dalmatian	DC048	5876	2008	12	89	2013
Big Foot	WR029	5235	2005	12	89	2013
Knotty Head	GC512	3557	2005	14	372	2013
Tubular Bells	MC725	4334	2003	12	89	2014
Lucius	KC875	7168	2009	13	182	2014
St. Malo	WR678	7036	2003	14	372	2014
Jack	WR759	6963	2004	14	372	2014
Samurai	GC432	3400	2009	12	89	2015
Heidelberg	GC859	5000	2009	13	182	2015
Kodiak	MC771	4986	2008	13	182	2015
Pony	GC468	3497	2006	14	372	2015
Freedom	MC948	6095	2008	15	691	2015
Stones	WR508	9556	2005	12	89	2016
Mission Deep	GC955	7300	1999	13	182	2016
Vito	MC984	4038	2009	13	182	2016
Tiber	KC102	4132	2009	15	691	2016
Kaskida	KC292	5860	2006	15	691	2016
Shenandoah	WR052	5750	2009	13	182	2017
Julia	WR627	7087	2007	12	89	2018
Buckskin	KC872	6920	2009	13	182	2018
Hadrian South	KC964	7586	2009	13	182	2019
Appomattox	MC392	7217	2009	15	691	2019
Cardamom	GB427	2720	2010	13	182	2020
Hadrian North	KC919	7000	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 9.12. Offshore exploration and production technology levels

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

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 forecast 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 make 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. For the Annual Energy Outlook 2012 projections, an algorthim was installed into the Alaska Oil & Gas Supply Submodule that assumed that North Slope fields would 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. The Annual Energy Outlook 2012 Issues in Focus article, entitled: “The Potential Shutdown of Alaska North Slope Oil Production,” discusses these assumptions and their rationale.

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 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 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 shale gas resources are highly uncertain and change over time as new information is gained through drilling, production, and technology experimentation. Over the last decade, as more shale formations have gone into production, the estimate of technically recoverable shale gas resources has skyrocketed. However, these increases in technically recoverable shale gas resources embody many assumptions that might not prove to be true over the long term and over the entire shale formation. For example, these shale gas resource estimates assume that gas production rates achieved in a limited portion of the formation are representative of the entire formation, even though neighboring shale gas well production rates can vary by as much as a factor of three. Moreover, the 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. Three cases were developed to examine the impact of the uncertainty inherent in these resource estimates by adjusting the estimated ultimate recovery (EUR) per well and the well spacing, both key components in the estimation of technically recoverable resources (see Issues in Focus article, U.S. Crude Oil and Natural Gas Resource Uncertainty).

Low EUR case. In this case, the EUR per tight oil 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 tight oil resource is decreased to 17 billion barrels and the shale gas resource is decreased to 241 trillion cubic feet, compared to 33 billion barrels of tight oil and 482 trillion cubic feet of shale gas assumed in the Reference case.

High EUR case. The EUR per tight oil and shale gas well is assumed to be 50 percent higher than in the Reference case, decreasing the per-unit cost of developing the resource. The total unproved technically recoverable tight oil resource is increased to 50 billion barrels and the shale gas resource is increased to 723 trillion cubic feet.

High TRR case. The well spacing for all tight oil and shale gas plays is assumed to be 8 wells per square mile (i.e., each well has an average drainage area of 80 acres) and the EUR per tight oil and shale gas wells are assumed to be 50 percent higher than in the Reference case. Additionally, production in the short term from the eight tight oil plays was adjusted to reflect the latest available data. The total unproved technically recoverable tight oil resource is increased to 89 billion barrels and the shale gas resource is increased to 1,091 trillion cubic feet, more than twice the Reference case tight oil and shale gas resource assumptions.

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 2035.

[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.