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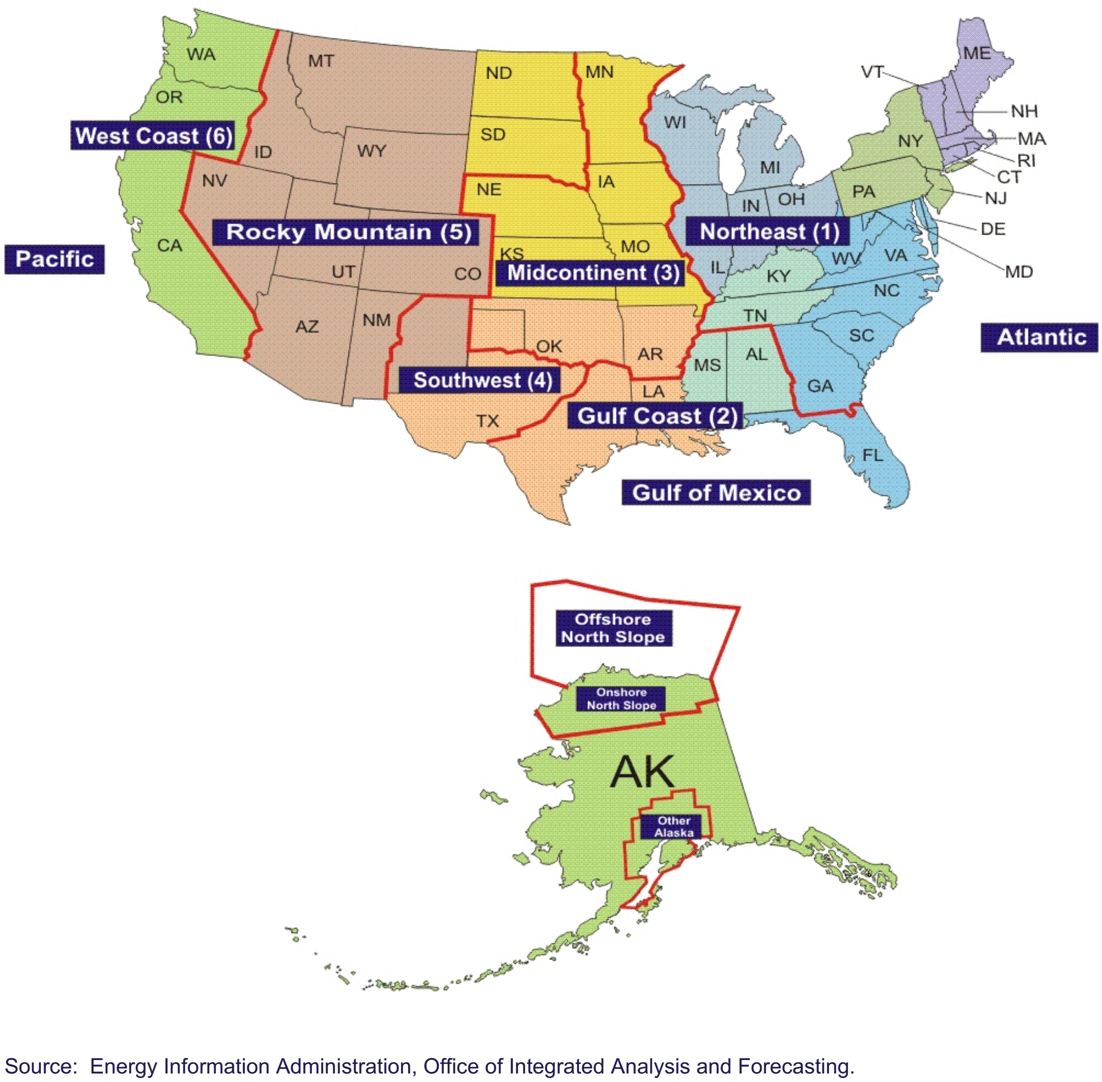
Oil and Gas Supply Module

The NEMS Oil and Gas Supply Module (OGSM) constitutes a comprehensive framework with which to analyze oil and gas supply on a regional basis (Figure 7). 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(2006), (Washington, DC, 2006). 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 7. Oil and Gas Supply Model Regions



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

OGSM encompasses domestic crude oil and natural gas supply by both conventional and nonconventional recovery techniques. Nonconventional recovery includes unconventional gas recovery from low permeability formations of sandstone and shale, and coalbeds.

Primary inputs for the module are varied. One set of key assumptions concerns estimates of domestic technically recoverable oil and gas resources. Other factors affecting the projection include the assumed rates of technological progress, supplemental gas supplies over time, and natural gas import and export capacities.

Key Assumptions

Domestic Oil and Gas Technically Recoverable Resources

Domestic oil and gas technically recoverable resources[82] consist of proved reserves,[83] inferred reserves,[84] and undiscovered technically recoverable resources.[85] OGSM resource assumptions are based on estimates of technically recoverable resources from the United States Geological Survey (USGS) and the Minerals Management Service (MMS) of the Department of the Interior.[86] Supplemental adjustments to the USGS nonconventional gas resources are made by Advanced Resources International (ARI), an independent consulting firm. For the *Annual Energy Outlook 2007*, two major adjustments are made to crude oil resources. Based on estimates from ARI, 3.6 billion barrels[87] are added to the Rocky Mountain region to reflect a revised assessment of the crude oil resource potential of the Williston basin Bakken formation. Based on estimates from the Reserves and Production Division of the EIA Office of Oil and Gas, 16.1 billion barrels [88] are added to US. inferred reserves to reflect a revised assessment of the potential of enhanced oil recovery to increase the recoverability of remaining in-place resources. 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 50 and 51 reflect the removal of intervening reserve additions between the date of the latest available assessment and January 1, 2005.

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 current producing fields and industry announced discoveries largely determine 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 2001 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 2006 are shown in Table 52. 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 MMS'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).

Table 50. Crude Oil Technically Recoverable Resources
(Billion barrels)

Crude Oil Resource Category	As of January 1, 2005
Undiscovered	51.62
Onshore	20.58
Northeast	1.17
Gulf Coast	5.23
Midcontinent	1.12
Southwest	2.97
Rocky Moutain	7.78
West Coast	2.32
Offshore	31.04
Deep (>200 meters Water Depth)	28.81
Shallow (0-200 meters Water Depth)	2.23
Inferred Reserves	63.91
Onshore	52.22
Northeast	1.05
Gulf Coast	5.20
Midcontinent	7.12
Southwest	17.90
Rocky Mountain	12.14
West Coast	8.80
Offshore	11.69
Deep (>200 meters Water Depth)	6.88
Shallow (0-200 meters Water Depth)	4.81
Total Lower 48 States Unproved	115.53
Alaska	30.70
Total U.S. Unproved	146.23
Proved Reserves	22.59
Total Crude Oil	168.82

Note: Resources in areas where drilling is officially prohibited are not included in this table. The Alaska value is not explicitly utilized in the OGSM, but is included here to complete the table. The Alaska value does not include resources from the Arctic Offshore Outer Continental shelf.

Source: Conventional Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS); Federal (Outer Continental Shelf) Offshore - Minerals Management Service (MMS); Proved Reserves - EIA, Office of Oil and Gas. Table values reflect removal of intervening reserve additions between the date of the latest available assessment and January 1, 2005.

Table 51. Natural Gas Technically Recoverable Resources
(trillion cubic feet)

Natural Gas Resource Category	As of January 1, 2005
Lower 48 Nonassociated Conventional Gas	509.27
Undiscovered	283.36
Onshore	119.06
Northeast	4.72
Gulf Coast	67.63
Midcontinent	14.39
Southwest	11.30
Rocky Mountain	14.68
West Coast	6.35
Offshore	164.30
Deep (>200 meters water depth)	106.30
Shallow (0-200 meters water depth)	58.00
Inferred Reserves	225.90
Onshore	175.85
Northeast	0.96
Gulf Coast	82.72
Midcontinent	59.08
Southwest	16.62
Rocky Mountain	15.74
West Coast	0.74
Offshore	50.05
Deep (>200 meters water depth)	5.95
Shallow (0-200 (meters water depth)	44.10
Unconventional Gas Recovery	477.52
• Tight Gas	277.73
Northeast	54.94
Gulf Coast	54.18
Midcontinent	10.82
Southwest	7.84
Rocky Mountain	149.47
West Coast	0.48
• Shale	125.81
Northeast	28.23
Gulf Coast	0.00
Midcontinent	44.45
Southwest	39.02
Rocky Mountain	14.11
West Coast	0.00
• Coalbed	73.99
Northeast	8.12
Gulf Coast	4.84
Midcontinent	5.62
Southwest	0.00
Rocky Mountain	55.41
West Coast	0.00
Associated-Dissolved Gas	130.84
Total Lower 48 Unproved	1117.62
Alaska	30.83
Total U.S. Unproved	1148.45
Proved Reserves	192.51
Total Natural Gas	1340.97

Sources and Notes for this table are listed in the 'Notes and Sources' section at the end of chapter.

Table 52. 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
Atlantis	GC699	6130	1998	15	691	2007
Atlas	LL050	8934	2003	11	45	2007
Cheyenne	LL399	8974	2004	11	45	2007
Cottonwood	GB244	2130	2001	11	45	2007
Crested Butte	GC242	2846	2004	11	45	2007
Jubilee	AT349	8776	2003	12	89	2007
MC837	MC837	1524	2000	11	45	2007
Merganser	AT037	8015	2001	11	45	2007
Neptune	AT575	6220	1995	13	182	2007
Puma	GC823	4129	2003	14	372	2007
Q	MC961	7926	2005	12	89	2007
San Jacinto	DC618	7814	2004	12	89	2007
Silvertip	AC815	9226	2004	11	45	2007
South Dachshund/Mondo	LL001	8351	2004	12	89	2007
Spiderman/Amazon	DC621	8082	2003	14	372	2007
Vortex	AT261	8344	2002	12	89	2007
Anduin	MC755	2400	2005	9	12	2008
Blind Faith	MC696	6989	2001	14	372	2008
Chinook	WR469	8831	2003	14	372	2008
Great White	AC857	8717	2002	15	691	2008
Jubilee Extension	LL309	8774	2005	11	45	2008
Knotty Head	GC512	3557	2005	15	691	2008
Shenzi	GC653	4238	2002	14	372	2008
Slammer	MC849	3598	2002	13	182	2008
St. Malo	WR678	7036	2003	14	372	2008
Stones	WR508	9556	2005	12	89	2008
Sturgis	AT182	3710	2003	12	89	2008
Tahiti	GC640	4292	2002	15	691	2008
Thunder Hawk	MC734	5724	2004	13	182	2008
Thunder Horse	MC778	5993	1999	17	2954	2008
Tobago	AC859	9493	2004	11	45	2008
Trident	AC903	9743	2001	13	182	2008
Atlas NW	LL005	8807	2004	11	45	2009
Baccarat	GC178	1404	2004	11	45	2009
Cascade	WR260	8143	2002	14	372	2009
EB197	EB197	1249	2004	11	45	2009
Entrada	GB782	4690	2000	14	372	2009
Goose	MC751	1624	2002	12	89	2009
Gretchen	GC114	2506	1999	9	12	2009
Sw Horseshoe	EB430	2285	2000	8	6	2009
Telemark	AT063	4457	2000	12	89	2009
Hack Wilson	EB598	3650	2001	12	89	2010
Hawkes	MC509	4082	2001	11	45	2010

Table 52. 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
Hornet	GC379	3878	2001	13	182	2010
Shiner Deep	GB700	4542	2003	11	45	2010
Tubular Bells	MC725	4334	2003	12	89	2010
Daniel Boone	GC646	4230	2004	11	45	2011
EB599	EB599	1250	2006	12	89	2011
GC767	GC767	5116	2004	11	45	2011
Longhorn	MC546	2460	2006	15	691	2011
MC161	MC161	2924	2005	11	45	2011
Thunder Horse North	MC776	5660	2000	16	1419	2011
Jack	WR759	6963	2004	17	2954	2012
Pony	GC468	3497	2006	13	182	2012
Raton	MC248	3400	2006	11	45	2012
Redrock	MC204	3334	2006	11	45	2012
Harrier	EB759	4114	2003	11	45	2013
Thunder Bird	MC819	5673	2006	11	45	2013
Casear	GC683	4457	2006	13	182	2014
Clipper	GC299	3452	2005	11	45	2014
Daredevil	LL095	9112	2005	11	45	2014
Great White West	AC856	7600	2006	11	45	2014
Kaskida	KC292	5860	2006	15	691	2014
Norman	GB434	5000	2006	15	691	2014
Claymore	AT140	3725	2006	11	45	2014
Egmont	MC413	2500	2006	13	182	2015
Grand Cayman	GB517	5000	2006	13	182	2015

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. The discovery year, initial production year, and field sizes are based on industry announcements and MMS estimates.

Synthetic Crude from Oil Shale

Projections for synthetic crude (syncrude) from oil shale are based on underground mining and surface retorting technology and costs. The facility parameter values and cost estimates assumed in the projection are based on information reported for the Paraho Oil Shale Project, with the costs converted into 2004 dollars.[89] Oil shale rock mining costs, however, are based on current Rocky Mountain underground coal mining costs, which are representative oil shale rock mining costs. Oil shale facility investment and operating costs are assumed to decline by 1 percent per year. The construction of commercial oil shale production facilities is not permitted prior to 2010, pending the implementation of a U.S. Department of Interior oil shale leasing program. Oil shale syncrude production facilities are assumed to be built when the net present value of the discounted cash flow exceeds zero. The discounted cash flow calculation uses a calculated discount rate that takes into consideration the financial risk associated with building oil shale facilities. Oil shale facilities take 5 years to construct, with an additional year required to bring a new facility into full production. An assumed technology penetration rate specifies that 5 years must pass from the time the first facility begins construction before the second facility can begin construction. Subsequent facilities are permitted to begin construction 3 years, 2 years, and then every year after a prior facility begins construction. Syncrude production is not resource constrained, approximately 400 billion barrels of syncrude resources exist in oil shale rock with at least 30 gallons per ton of rock.

Alaska Crude Oil

Alaska crude oil production is determined by the estimates of available resources in undeveloped areas and the time and expense required to begin production in these areas. Alaska production includes existing producing fields, fields that have been discovered but are not currently being produced, and fields that are projected to exist, based upon the region's geology. The first category of field includes expansion fields in the Prudhoe Bay region, accounting for 800 million barrels of oil resources. These fields are relatively small, and development of these fields began in 2002 and continues throughout the projections. The estimated size of these expansion fields corresponds to projections made by the State of Alaska and other analysis by EIA.

Fields in the second category include fields in the National Petroleum Reserve Alaska, or NPR-A. In 1999, 2002, and 2004, northeastern portions of the NPR-A were leased by the Federal government for oil and gas exploration and production. According to a recent USGS assessment[90] NPR-A is estimated to contain a mean resource level of 10.6 billion barrels. These resources are assumed not be brought into production until after 2007. Finally, a total of roughly 800 million barrels of additional resources are in other fields yet to be discovered, both on the North Slope of Alaska and offshore in the Beaufort Sea. These fields are expected to be smaller than recent finds like the Alpine field. Oil and gas exploration and production currently are not permitted in the Alaska National Wildlife Refuge. The AEO2007 projections for Alaska oil and gas production presume that this prohibition remains in effect throughout the projection.

Supplemental Natural Gas

The projection for supplemental gas supply is identified for three separate categories: synthetic natural gas (SNG) from liquids, SNG from coal, and other supplemental supplies (propane-air, coke oven gas, refinery gas, biomass air, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas). SNG from the currently operating Great Plains Coal Gasification Plant is assumed to continue through the forecast period, at an average historical level of 50.8 billion cubic feet per year. Other supplemental supplies are held at a constant level of 16.5 billion cubic feet per year throughout the forecast because this level is consistent with historical data and it is not believed to change significantly in the context of a reference case forecast. Synthetic natural gas from liquid hydrocarbons in Hawaii is assumed to continue over the forecast at the average historical level of 2.7 billion cubic feet per year.

Legislation and Regulations

The Outer Continental Shelf Deep Water Royalty Act (Public Law 104-58) gave the Secretary of 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 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 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 volume 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 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 depth 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 Minerals Management Service 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 combusion of fossil fuels in power plants and large industrial processes. For AEO2007, additional oil resources have bee added to account for increassed use of CO_2 enhanced oil recovery technology.

Rapid and Slow Technology Cases

Two alternative cases were created to assess the sensitivity of the projections to changes in the assumed rates of progress in oil and natural gas supply technologies. To create these cases a number of parameters representing technological penetration in the reference case were adjusted to reflect a more rapid and a slower penetration rate. In the reference case, the underlying assumption is that technology will continue to penetrate at historically observed rates. Since technologies are represented somewhat differently in different submodules of the Oil and Gas Supply Module, the approach for representing rapid and slow technology penetration varied as well. For instance, the effects of technological progress on conventional oil and natural gas parameters in the reference case, such as finding rates, drilling, lease equipment and operating costs, and success rates, were adjusted upward and downward by 50 percent (Table 53), for the rapid and slow technology cases, respectively. The approach taken in unconventional natural gas is discussed below.

In the Canadian supply submodule, successful natural gas wells and production levels in the Western Canadian Sedimentary Basin (WCSB) are assumed to be progressively greater in the rapid technology case and lesser in the slow technology case across the forecast horizon. By 2030, the number of successful natural gas wells associated with conventional and tight formations are approximately 13 percent higher and lower in the rapid and slow technology cases than in the reference case due to differences in assumed technological improvements. Potential production rates from conventional new discoveries are adjusted upward and downward by 25 percent in the rapid and slow technology cases, respectively. The resource base levels for the WCSB were assumed not to vary across technology cases. The technology parameter on production from coal bed natural gas wells is adjusted upward and downward by 50 percent under the rapid and slow technology cases, resulting in production levels approximately 25 percent higher or lower due to assumed technological differences. Finally, the minimum supply prices deemed necessary to trigger the Alaska and MacKenzie Delta natural gas pipelines are progressively decreased or increased over the forecast in the rapid and slow technology cases, respectively, downward or upward from 0.0 to 12.5 percent by 2030. All other parameters in the model were kept at their reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of LNG and natural gas trade between the United States and Mexico.

The Unconventional Gas Recovery Supply Submodule (UGRSS) relies on Technology Impacts and Timing functions to capture the effects of technological progress on costs and productivity in the development of gas from deposits of coalbed methane, gas shales, and tight sands. The numerous research and technology initiatives are combined into 11 specific “technology groups,” that encompass the full spectrum of key disciplines — geology, engineering, operations, and the environment. The technology groups utilized for the *Annual Energy Outlook 2005* are characterized for three distinct technology cases — Slow Technological Progress, Reference Case, and Rapid Technological Progress — that capture three different futures for technology progress. The 11 technology groups are listed in Table 54. Table 55 provides a description of their treatment under the different technology cases.

Table 53. Assumed Annual Rates of Technological Progress for Conventional Crude Oil and Natural Gas Sources
(percent/year)

Category	Slow	Reference	Rapid
Lower 48 Onshore			
Costs			
Drilling	0.45	0.89	1.34
Lease Equipment	0.29	0.58	0.87
Operating	0.19	0.38	0.57
Finding Rates			
New Field Discoveries	0.00	0.00	0.00
Known Fields	0.50	1.00	2.00
Success Rates			
Exploratory	0.25	0.50	0.75
Developmental	0.25	0.50	0.75
Lower 48 Offshore			
Exploration success rates	0.50	1.00	1.50
Delay to commence first exploration and between exploration (years)	0.25	0.50	1.00
Exploration and Development drilling costs	0.50	1.00	1.50
Operating costs	0.50	1.00	1.50
Time to construct production facility (years)	0.25	0.50	1.00
Production facility construction costs	0.50	1.00	1.50
Initial constant production rate	0.25	0.50	1.00
Production Decline rate	0.00	0.00	0.00
Alaska			
Costs			
Drilling	0.50	1.00	1.50
Lease Equipment	0.50	1.00	1.50
Operating	0.50	1.00	1.50
Finding Rates	1.50	3.00	4.50

Source: The values shown in this table are developed by the Energy Information Administration, Office of Integrated Analysis and Forecasting from econometric analysis for onshore costs and discussions with various industry and government sources for offshore and Alaska costs. Onshore drilling cost data are based on the American Petroleum Institute's *Joint Association Survey on Drilling Costs*. Onshore lease equipment and operating costs are based on the Energy Information Administration's *Costs and Indices for Domestic Oil & Gas Field Equipment and Production Operations*.

Table 54. Technology Types and Impacts

Technology Group	Technology Type	Impact
1	Basin assessments	Increase the available resource base by a) accelerating the time that hypothetical plays in currently unassessed areas become available for development and b) increasing the play probability for hypothetical plays – that portion of a given area that is likely to be productive.
2	Play specific, extended reservoir characterizations	Increase the pace of new development by accelerating the pace of development of emerging plays, where projects are assumed to require extra years for full development compared to plays currently under development.
3	Advanced well performance diagnostics and remediation	Expand the resource base by increasing reserve growth for already existing reserves.
4	Advanced exploration and natural fracture detection R&D	Increases the success of development by a) improving exploration/development drilling success rates for all plays and b) improving the ability to find the best prospects and areas.
5	Geology technology modeling and matching	Matches the “best available technology” to a given play with the result that the expected ultimate recovery (EUR) per well is increased.
6	More effective, lower damage well completion and stimulation technology	Improves fracture length and conductivity, resulting in increased EUR’s per well.
7	Targeted drilling and hydraulic fracturing R&D	Results in more efficient drilling and stimulation which lowers well drilling and stimulation costs.
8	New practices and technology for gas and water treatment	Result in more efficient gas separation and water disposal which lowers water and gas treatment operation and maintenance costs.
9	Advanced well completion technologies, such as cavitation, horizontal drilling, and multi-lateral wells:	Defines applicable plays, thereby accelerating the date such technologies are available and introduces and improved version of the particular technology, which increases EUR per well.
10	Other unconventional gas technologies, such as enhanced coalbed methane and enhanced gas shales recovery	Introduce dramatically new recovery methods that a) increase EUR per well and b) become available at dates accelerated by increase R&D, with c) increased operation and maintenance costs (in the case of coalbed methane) for the incremental gas produced.
11	Mitigation of environmental constraints	Removes development constraints in environmentally sensitive basins, resulting in an increase in basin areas available for development.

Source: Advanced Resources International.

Table 55. Assumed Rates of Technological Progress for Unconventional Gas Recovery

Technology Group	Item	Type of Deposit	Technology Case		
			Slow	Reference	Rapid
1	Year Hypothetical Plays Become Available	All Types-Non DOE	NA	NA	NA
		All Types-DOE	NA	2016	2009
2	Decrease in Extended Portion of Development Schedule for Emerging Plays (per year)	Coalbed Methane and Tight Sands - Non DOE	0.83%	1.67%	2.50%
		Gas Shales-Non DOE	1.25%	2.50%	3.75%
		All Types - DOE	1.25%	2.50%	3.75%
3	Expansion of Existing Reserves (per year -declining 0.1% per year; eg., 3.0, 2.0...)	Tight Sands	1.0%	2.0%	3.0%
		Coalbed Methane & Gas Shales	2.0%	4.0%	6.0%
4	Increase in Percentage of Wells Drilled Successfully (per year)	All Types	0.1%	0.2%	0.3%
	Year that Best 30 Percent of Basin is Fully Identified	All Types	2100	2044	2031
5	Increase in EUR per Well (per year)	All Types	0.13%	0.25%	0.38%
6	Increase in EUR per Well (per year)	All Types	0.13%	0.25%	0.38%
7	Decrease in Drilling and Stimulation Costs per Well (per year)	All Types	NA	NA	NA
8	Decrease in Water and Gas Treatment O&M Costs per Well (per year)	All Types	NA	NA	NA
9	Year Advanced Well Completion Technologies Become Available	Coalbed Methane	NA	NA	NA
		Tight Sands &Gas Shales	NA	2016	2009
	Increase in EUR per well (total increase)	Coalbed Methane	NA	NA	NA
		Tight Sands	NA	10%	15%
		Gas Shales	NA	20%	30%
10	Year Advanced Recovery Technologies Become Available	Coalbed Methane & Tight Sands	NA	NA	2023
		Gas Shales	NA	NA	NA
	Increase in EUR per well (total increase)	Coalbed Methane	NA	NA	45%
		Tight Sands	NA	NA	15%
		Gas Shales	NA	NA	NA
	Increase in Costs ($1996/Mcf) for Incremental CBM production	Coalbed Methane	NA	NA	1.75
		Tight Sands	NA	NA	0.75
		GasShales	NA	NA	NA
11	Proportion of Areas Current Restricted that become Available for Development (per year)	All Types - Non DOE	0.5%	1.0%	1.5%
		All Types - DOE	0.25%	0.5%	0.75%

EUR = Estimated Ultimate Recovery.
O&M = Operation & Maintenance.
CBM = Coalbed Methane.
NA = Not applicable.
DOE = Those plays in the Rocky Mountain basins assessed as part of Department of Energy sponsored basin studies.
Source: Reference Technology Case, Advanced Resources, International; Slow and Rapid Technology Cases, Energy Information Administration, Office of Integrated Analysis and Forecasting.

Notes and Sources

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

[83] 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.

[84] Inferred reserves are that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves.

[85] Undiscovered resources 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.

[86] Donald L. Gautier and others, U.S. Department of Interior, U.S. Geological Survey, 1995 National Assessment of the United States Oil and Gas Resources, (Washington, D.C., 1995); U.S. Department of 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.

[87] This includes 2.1 billion barrels of undiscovered technically recoverable resources and 1.5 billion barrels of inferred reserves.

[88] The amounts added (in billion barrels) among the various OGSM regions are as follows: Northeast 0.4, Gulf Coast 5.0, Midcontinent 3.8, Southwest 4.1, Rocky Mountain 1.5, and West Coast 1.3.

[89] Source: Noyes Data Corporation, *Oil Shale Technical Data Handbook*, edited by Perry Nowacki, Park Ridge, New Jersey, 1981, pages 89-97. The Paraho Oil Shale Project design had a maximum production rate of 100,000 syncrude barrels per day, which is used in the OSSS as the standard oil shale facility size.

[90] U.S. Geological Survey, 2002 Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (NPRA): Play Maps and Technically Recoverable Resource Estimates, Open- File Report 02-207 (May 2002).

Notes and Sources for Table 51

Note: Resources in areas where drilling is officially prohibited are not included in this table. Also, the Associated-Dissolved Gas and the Alaska values are not explicitly utilized in the OGSM, but are included here to complete the table. The Alaska value does not include stranded Arctic gas.

Source: Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS) with adjustments to Unconventional Gas Recovery resources by Advanced Resources, International; Federal (Outer Continental Shelf) Offshore - Minerals Management Service (MMS); Proved Reserves -- EIA, Office of Oil and Gas. Table values reflect removal of intervening reserve additions between the date of the latest available assessment and January 1, 2005.