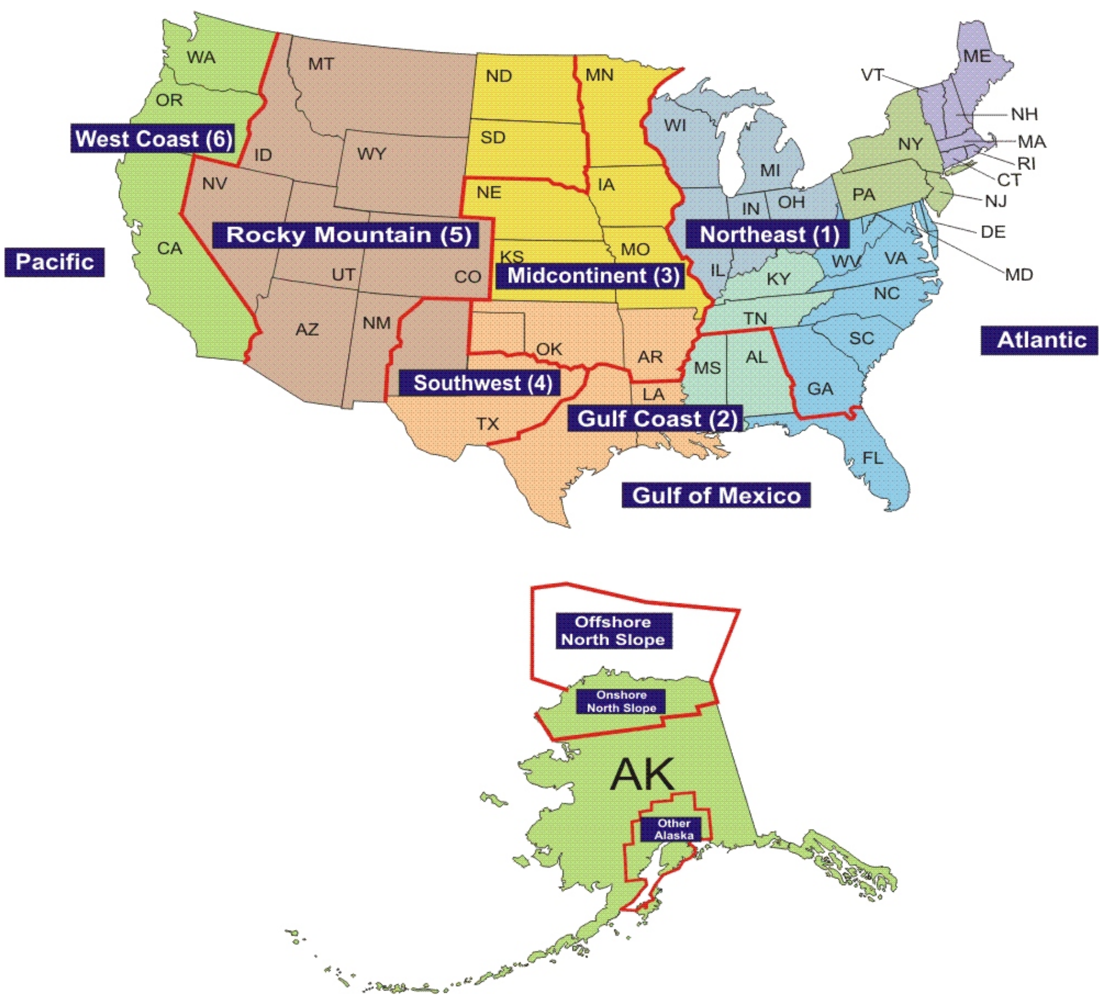
Report #:DOE/EIA-0554(2006)
Release date: March 2006
Next release date: March 2007

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, acquire natural gas from foreign producers for resale in the United States, or sell U.S. gas to foreign consumers.

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. Foreign gas transactions may occur via either pipeline (Canada or Mexico) or transport ships as liquefied natural gas (LNG).

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[84] consist of proved reserves,[85] inferred reserves,[86] and undiscovered technically recoverable resources.[87] 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.[88] Supplemental adjustments to the USGS nonconventional resources are made by Advanced Resources International (ARI), an independent consulting firm. 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, 2004.

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 2-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 2003 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, 2004
Undiscovered	47.29
Onshore	18.49
Northeast	1.10
Gulf Coast	5.24
Midcontinent	1.13
Southwest	2.97
Rocky Moutain	5.72
West Coast	2.32
Offshore	28.80
Deep (>200 meters Water Depth)	26.99
Shallow (0-200 meters Water Depth)	1.82
Inferred Reserves	45.90
Onshore	35.72
Northeast	0.61
Gulf Coast	0.36
Midcontinent	3.43
Southwest	14.17
Rocky Mountain	9.52
West Coast	7.63
Offshore	10.18
Deep (>200 meters Water Depth)	5.44
Shallow (0-200 meters Water Depth)	4.75
Total Lower 48 States Unproved	93.19
Alaska	30.92
Total U.S. Unproved	124.11
Proved Reserves	23.11
Total Crude Oil	147.22

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, 2004.

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

Natural Gas Resource Category	As of January 1, 2004
Nonassociated Gas	
Undiscovered	268.19
Onshore	122.44
Northeast	4.83
Gulf Coast	68.69
Midcontinent	14.51
Southwest	11.65
Rocky Mountain	16.41
West Coast	6.35
Offshore	145.75
Deep (>200 meters water depth)	88.95
Shallow (0-200 meters water depth)	56.80
Inferred Reserves	224.41
Onshore	177.44
Northeast	1.48
Gulf Coast	85.88
Midcontinent	61.63
Southwest	17.76
Rocky Mountain	9.89
West Coast	0.81
Offshore	46.97
Deep (>200 meters water depth)	3.69
Shallow (0-200 (meters water depth)	43.28
Unconventional Gas Recovery	469.92
• Tight Gas	300.33
Northeast	55.82
Gulf Coast	59.00
Midcontinent	11.90
Southwest	8.81
Rocky Mountain	164.32
West Coast	0.48
• Shale	83.32
Northeast	28.78
Gulf Coast	0.00
Midcontinent	0.00
Southwest	40.39
Rocky Mountain	14.15
West Coast	0.00
• Coalbed	75.18
Northeast	8.31
Gulf Coast	1.82
Midcontinent	5.77
Southwest	0.00
Rocky Mountain	59.28
West Coast	0.00
Associated-Dissolved Gas	132.14
Total Lower 48 Unproved	1083.56
Alaska	31.43
Total U.S. Unproved	1115.00
Proved Reserves	189.04
Total Natural Gas	1304.04

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
Gomez	MC755	3098	1986	11	45	2006
Rigel	MC252	5225	2003	11	45	2006
Thunder Horse	MC778	6050	1999	16	1419	2006
Ticonderoga	GC768	5250	2004	11	45	2006
Triton/Poseiden (MC)	MC726	5373	2002	12	89	2006
Wrigley	MC506	3700	2005	12	89	2006
Atlantis	GC699	6130	1998	15	691	2007
Constitution	GC680	5071	2003	14	372	2007
Entrada	GB782	4690	2000	14	372	2007
Jubilee	AT349	8825	2003	13	182	2007
Lorien	GC199	2315	2003	12	89	2007
San Jacinto	DC618	7850	2004	11	45	2007
Spiderman/Amazon	DC621	8087	2002	14	372	2007
Vortex	AT261	8344	2002	13	182	2007
Atlas	LL050	8934	2003	12	89	2008
Blind Faith	MC696	6989	2001	13	182	2008
Cascade	WR206	8143	2002	13	182	2008
Merganser	AT037	7900	2002	11	45	2008
Neptune	AT575	6220	1995	14	372	2008
Shenzi	GC653	4238	2002	14	372	2008
Slammer	MC849	3598	2002	13	182	2008
South Dachshund/Mondo	LL002	8340	2004	11	45	2008
Tahiti	GC640	4017	2002	15	691	2008
Basil Peak	GB244	2120	2001	11	45	2009
Chinook	WR469	8831	2003	14	372	2009
Hawkes	MC509	4174	2001	11	45	2009
Hornet	GC379	2076	2001	13	182	2009
Seventeen Hands	MC299	5448	2001	12	89	2009
Sturgis	AT183	3710	2003	12	89	2009
Telemark	AT063	4457	2000	12	89	2009
Trident	AC903	9743	2001	14	372	2009
Tubular Bells	MC725	4334	2003	12	89	2009
Anduin	MC755	2904	2005	11	45	2010
Great White	AC857	8009	2002	15	691	2010
Puma	GC823	4129	2004	12	89	2010
St. Malo	WR678	7036	2003	14	372	2010
Thunder Hawk	MC734	5724	2004	12	89	2010

Source: Energy Information Administration, Office of Integrating 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. These fields are relatively small, and development of these fields began in 2002 and continues throughout the forecast. 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 2007. Finally, a total of roughly 800 million barrels of additional resources are projected to be developed 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 AEO2005 projections for Alaska oil and gas production presume that this prohibition remains in effect throughout the forecast period.

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 52.5 billion cubic feet per year. Other supplemental supplies are held at a constant level of 18.9 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

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 is

(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 200 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 200 to 400 and 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.

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 for conventional gas and production levels for unconventional gas in the WCSB are assumed to be progressively greater in the rapid technology case and lesser in the slow technology case across the forecast horizon. By 2025, the number of successful natural gas wells are approximately 12 percent higher and lower in the rapid and slow technology cases than in the reference case directly 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 unconventional natural gas wells is adjusted upward and downward by 50 percent under the rapid and slow technology cases, resulting in production levels approximately 15 percent higher or lower directly due to assumed technological improvements. 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 2025. 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	0.38	0.76	1.14
Operating	0.26	0.52	0.78
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	0.60	1.20	1.80
Time to construct production facility (years)	0.30	0.60	0.90
Production facility construction costs	0.60	1.20	1.80
Initial constant production rate	0.30	0.60	0.90
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	2021	2021
2	Decrease in Extended Portion of Development Schedule for Emerging Plays (per year)	All Types - Non DOE	0.83%	1.67%	2.50%
		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	2019
		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 ($1998/Mcf) for Incremental CBM production	Coalbed Methane	NA	NA	0.75
		Tight Sands	NA	NA	0.00
		GasShales	NA	NA	NA

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

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

[85] 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.

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

[87] 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.

[88] 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, an Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf, OGS Report MMS 96-0034 (June 1996); and 2003 estimates of conventionally recoverable hydrocarbon resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 2003.

[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, 2004.