10 Natural Gas

This chapter describes how natural gas supply, demand, and costing are modeled in EPA Base Case v.4.10. Section 10.1 indicates that natural gas supply dynamics are directly (i.e., endogenously) modeled in the new base case. This contrasts to previous EPA base cases where natural gas supply curves and related assumptions were developed outside of IPM and then treated as an (exogenous) input to the base case. Section 10.2 gives an overview of the new natural gas module. Section 3.9 treats in detail the specific components of the module that are only briefly described in Section 10.2. Specifically, Sections 10.3 and 10.4 describe the very detailed process-engineering model and data sources used to characterize North American conventional, unconventional, and frontier natural gas resources and reserves and to derive all the cost components incurred in bringing natural gas from the ground to the pipeline. These sections also discuss resource constraints affecting production and the assumptions (in the form of cost indices) used to depict expected changes in costs over the 2012-2050 modeling time horizon.

Section 10.5 describes how liquefied natural gas (LNG) imports are represented in the natural gas module. The section covers the assumptions regarding liquefaction facilities, LNG supply, regasification capacity, and related costs. Section 10.6 turns to demand side issues, in particular, how non-power sector residential, commercial, and industrial demand is represented. Section 10.7 describes the detailed characterization of the natural gas pipeline network, the pipeline capacity expansion logic, and the assumptions and procedures used to capture pipeline transportation costs. Section 10.8 treats issues related to natural gas storage: capacity characterization and expansion logic, injection/withdrawal rates, and associated costs. Section 10.9 describes the crude oil and natural gas liquids (NGL) price projections that are exogenous inputs in the natural gas module. They figure in the modeling of natural gas because they are a source of revenue which influence the exploration and development of hydrocarbon resources. The chapter concludes in Section 10.10 with a discussion of key gas market parameters in the report and proxy natural gas supply curves from the new integrated model based on results in EPA Base Case v.4.10. The proxy curves are meant to provide a point of comparison with the natural gas supply curves used in previous EPA IPM base case.

10.1 Overview of IPM's Natural Gas Module

In previous EPA base cases natural gas supply curves and related assumptions were developed outside of IPM and provided in an iterative fashion as static inputs to the base case. Regional gas price forecast, in the form of basis differentials[1], was also provided as static inputs for delivered gas price calculations. The iteration process began with a set of supply curves and basis differentials generated from a series of runs using external stand-alone gas model. Results from the IPM run such as power sector gas demand and heat rates were fed back to the gas model as inputs for the next iteration. It was a time consuming process as it took several iterations to converge and involving human interaction between iterations.

In EPA Base Case v.4.10 natural gas supply, demand, transportation, storage, and related costs are modeled directly in IPM through the incorporation of a new natural gas module. In the new system, natural gas supply curves are generated endogenously for each region, and the balance between the natural gas supply and demand is solved in all regions simultaneously. Integrating natural gas modeling into IPM as illustrated in Figure 10-1 and Figure 10-2 has some advantages over the previous modeling approach. The direct interaction between the electric and the gas modules captures the overall gas supply and demand dynamic and requires no iteration. The

[1] In natural gas discussions “basis” refers to differences in the price of natural gas in two different geographical locations. In the marketplace “basis” typically means the difference between the NYMEX futures price at the Henry Hub and the cash price at other market points. In the modeling context “basis” means the difference in natural gas prices between any two nodes at the same instance in time.

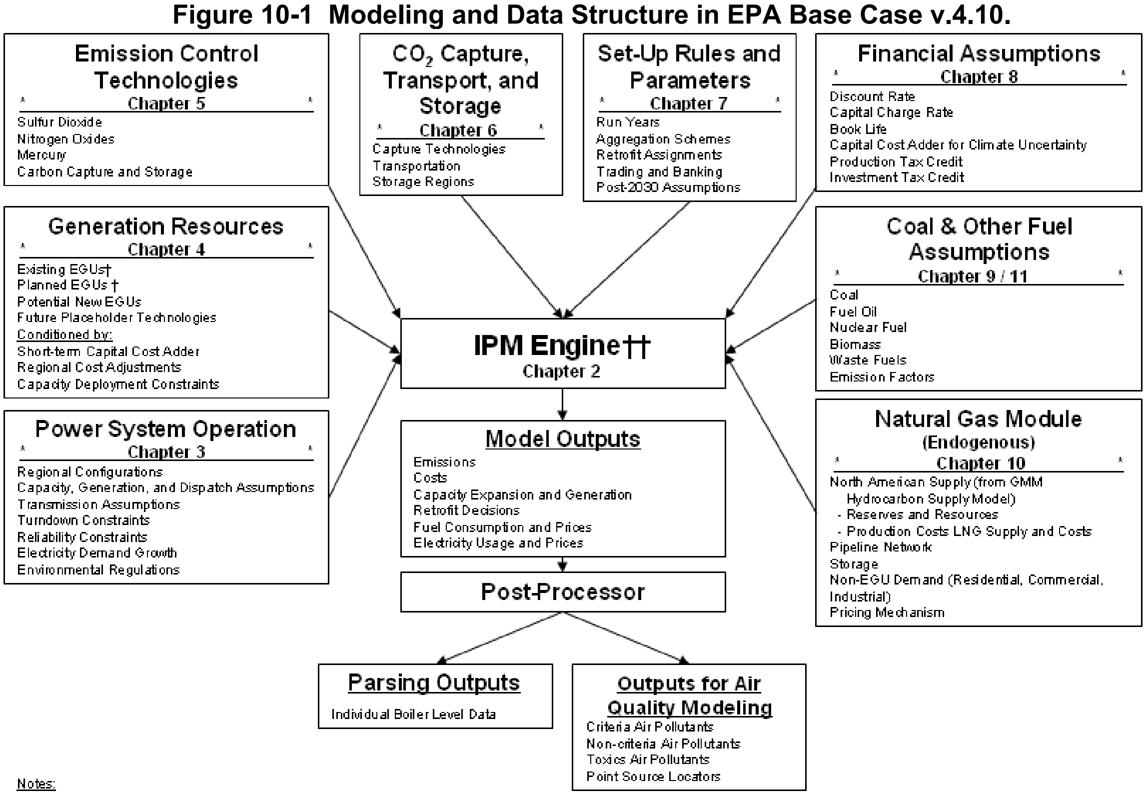
model solves for gas price in each region, therefore, it does not need to import gas price basis differentials as in the previous approach.

The result from a modeling standpoint is a new integrated natural gas module with a linear programming (LP) structure that is fully consistent and compatible with that used in IPM. Natural gas LP components, which include objective function parameters consistent in form with IPM's cost minimization, a series of decision variables, and a set of constraints, have been added to the original LP structure of the IPM electricity module. This integration makes the gas module a working component of the IPM modeling framework.

To a certain extent, the design and assumptions of the new natural gas module are similar to those in ICF International's private practice Gas Market Model (GMM) which has been used extensively for forecasting and market analyses in the North American natural gas market. To provide these new natural gas modeling capabilities within IPM and still maintain an acceptable model size and solution time, however, simplifications of some of the GMM design and assumptions were made.

Seasonality in the gas module is made consistent with that in IPM and is currently modeled with two seasons (summer and winter), each with up to six IPM load periods that correspond to the IPM electric sector load duration curve (LDC) segments. The gas module also employs a similar run year concept as in IPM where, in order to manage model size, individual calendar years over the entire modeling period are mapped to a lesser number of run years. In the current version, both modules use the same run year mapping.

Figure 10-1 Modeling and Data Structure in EPA Base Case v.4.10.

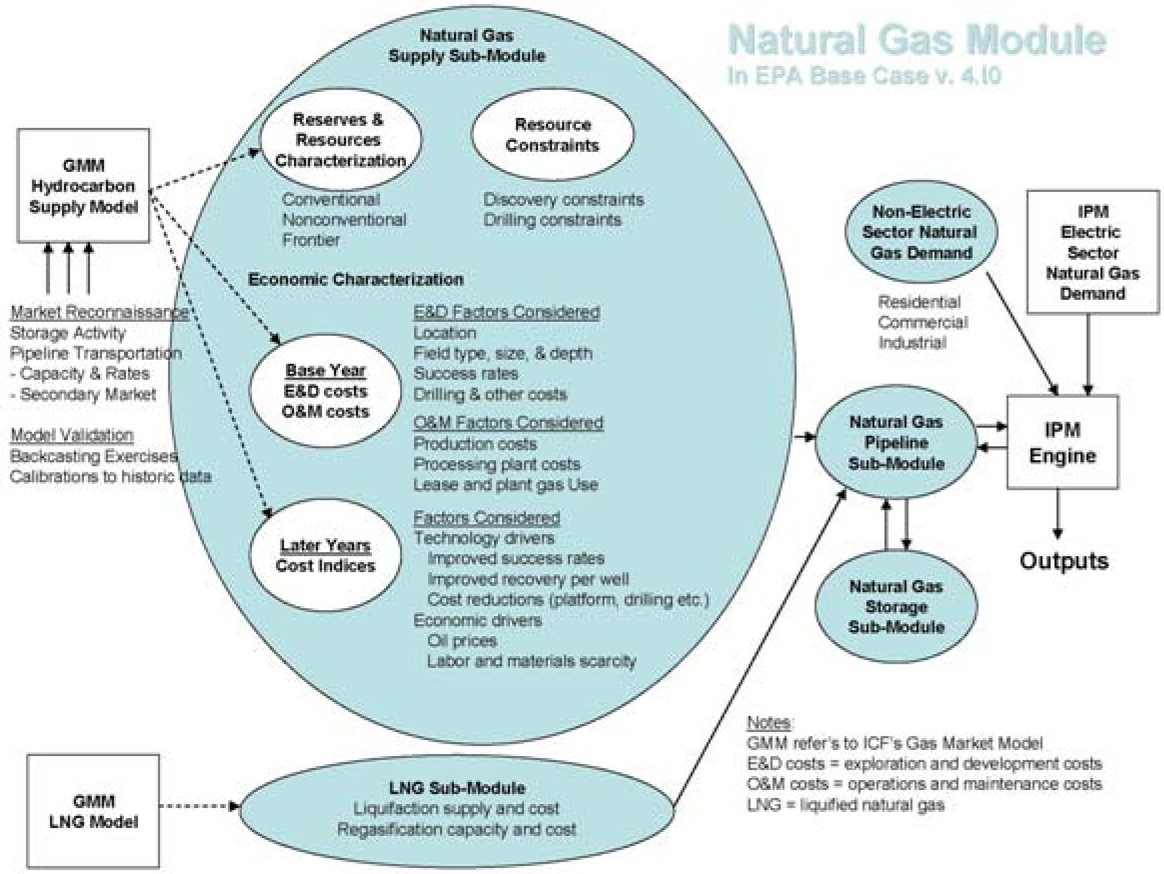


Notes:

† Information on existing and planned electric generating units (EGUs) is contained in the National Electrical Energy Data System (NEEDS) data base maintained for EPA by ICF International. Planned EGUs are those which were under construction or had obtained financing at the time that the EPA Base Case was finalized.

††IPM Engine is the model structure described in Chapter 2

Figure 10-2 Natural Gas Module in EPA Base Case v.4.10.



10.2 Key Components of the New IPM Natural Gas Module

The new gas module is a full supply/demand equilibrium model of the North American gas market. Most of the structure and data for the gas module are derived from ICF's Gas Market Model (GMM). It consists of 114 supply/demand/storage nodes and 14 LNG regasification facility locations that are tied together by a series of links that represent the North American natural gas transmission network as shown in Figure 10-3. The list of the 114 nodes is tabulated in Table 10-1.

Key elements of the natural gas module (which are described in detail in Sections 10.3-10.9) include:

Natural Gas Resources are modeled by a set of base year resource cost curves, which represent undiscovered resource availability or recoverable resource as a function of exploration & development (E&D) cost for 77 supply regions. "Resource Appreciation"[2] is added to the resource base to account for additional resources from plays that are not included in the resource base estimates due to lack of knowledge and technology to economically recover the resources. The construction of the resource cost curves are based on resource characterizations and economic evaluations from the Hydrocarbon Supply Model (HSM) of the GMM. (The HSM is discussed in greater detail in Sections 10.3 and 10.4 below.) Figure 10-4 depicts the geographic locations of the supply regions and Table 10-2 provides a list of the supply regions and a mapping of the regions to the modeling nodes.

Natural Gas production from the 77 supply regions is calculated from the resource cost curves based on exploration and development activities that are a function of drilling success rate, rigs availability, reserves-to-production (R/P) ratio, and the costs of exploration, reserves development, and production that are applicable in the specific regions.

LNG import level for each of the LNG regasification facilities is calculated from LNG supply availability curves (derived from the LNG supply curve module of GMM) based on the solution gas price and the regasification capacity at the corresponding LNG node. Availability and regasification capacity of the facilities are specified as inputs. The model has the capability to expand regasification capacity. However, due to excess of LNG regasification capacity already in the system and a relatively low electricity demand growth assumption in the EPA Base Case v.4.10, the regasification expansion feature is turned off. If future economic demands more LNG capacity, it can be turned back on.

End use natural gas demand for the non-power sectors (i.e. the residential, commercial, and industrial sectors) is incorporated in the IPM LP structure through node-level interruptible and firm demand curves derived from the GMM natural gas demand module. (These are discussed in greater detail in Section 10.6 below.) The gas consumption in the non-power sectors is calculated within the gas module and the power sector consumption is calculated within the IPM electricity dispatch module. Figure 10-5 shows the geographic locations of the demand regions.

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[2] Resource appreciation represents growth in ultimate resource estimates attributed to success in extracting resource from known plays such as natural gas from shales, coal seams, offshore deepwater, and gas hydrates that are not included in the resource base estimates.

Figure 10-3 Gas Transmission Network Map

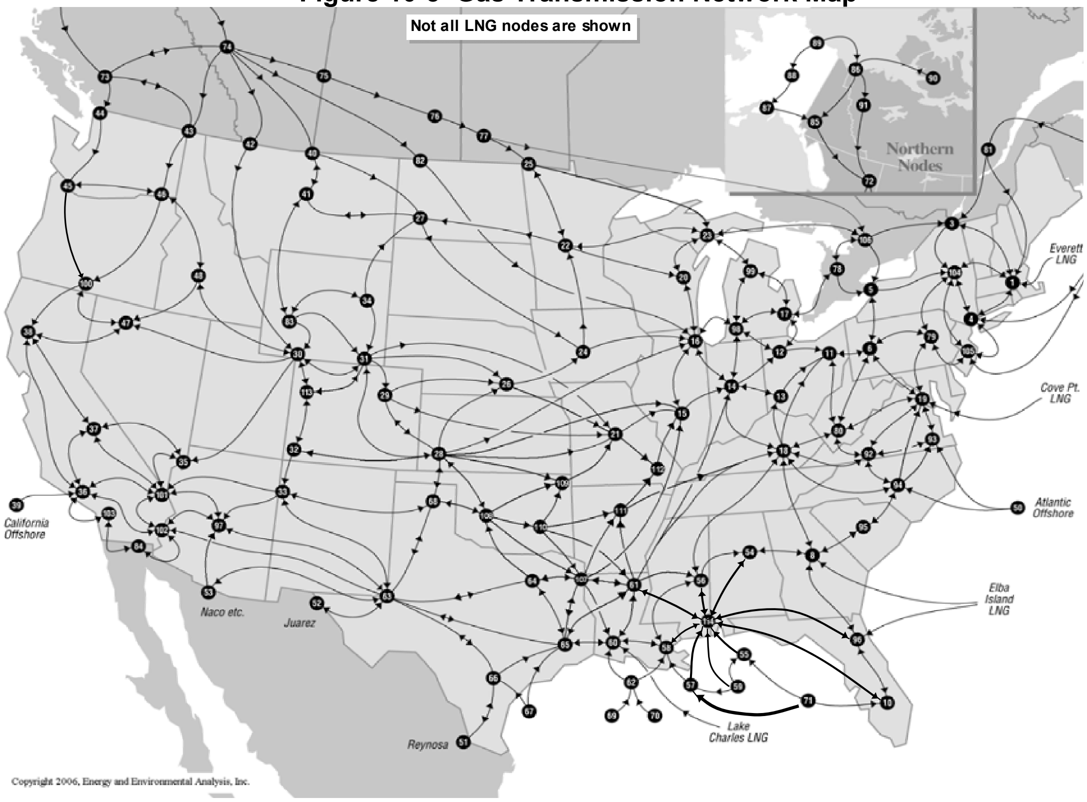


Table 10-1 List of Nodes

Node	Name	Supply	Demand	Transit, Import/ Export	Underground Storage	Peakshaving Storage
1	New England		X			X
2	Everett TRANS			X		
3	Quebec		X			X
4	New York City		X			X
5	Niagara	X	X		X	X
6	Leidy	X	X		X	X
7	Cove Point TRANS			X		
8	Georgia		X			X
9	Elba Is TRANS			X		
10	South Florida		X			X
11	East Ohio	X	X		X	X
12	Maumee/Defiance	X	X			X
13	Lebanon	X	X			X
14	Indiana	X	X		X	X
15	South Illinois	X	X		X	X
16	North Illinois	X	X		X	X
17	Southeast Michigan	X	X		X	X
18	Tennessee/Kentucky	X	X		X	X
19	MD/DC/Northern VA		X			X
20	Wisconsin	X	X			X

Node	Name	Supply	Demand	Transit, Import/ Export	Underground Storage	Peakshaving Storage
21	Northern Missouri	X	X			X
22	Minnesota	X	X		X	X
23	Crystal Falls	X	X			X
24	Ventura	X	X		X	X
25	Emerson Imports			X		
26	Nebraska	X	X		X	X
27	Great Plains			X		
28	Kansas	X	X		X	X
29	East Colorado	X	X		X	X
30	Opal	X	X		X	X
31	Cheyenne	X	X		X	
32	San Juan Basin	X	X		X	
33	EPNG/TW	X	X			X
34	North Wyoming	X	X		X	
35	South Nevada	X	X			X
36	SOCAL Area	X	X		X	X
37	Enhanced Oil Recovery Region	X	X			
38	PGE Area	X	X		X	X
39	Pacific Offshore	X				
40	Monchy Imports			X		
41	Montana/North Dakota	X	X		X	X
42	Wild Horse Imports			X		
43	Kingsgate Imports			X		
44	Huntingdon Imports			X		
45	Pacific Northwest	X	X		X	X
46	NPC/PGT Hub		X			X
47	North Nevada	X	X			X
48	Idaho	X	X			X
49	Eastern Canada Offshore	X				
50	Atlantic Offshore	X				
51	Reynosa Imp/Exp			X		
52	Juarez Imp/Exp			X		
53	Naco Imp/Exp			X		
54	North Alabama	X	X		X	X
55	Alabama Offshore	X				
56	North Mississippi	X	X		X	X
57	East Louisiana Shelf	X				
58	Eastern Louisiana Hub	X	X		X	X
59	Viosca Knoll/Desoto/Miss Canyon	X				
60	Henry Hub	X	X		X	X
61	North Louisiana Hub	X	X		X	X
62	Central and West Louisiana Shelf	X				
63	Southwest Texas	X	X		X	
64	Dallas/Ft Worth	X	X		X	X
65	E. TX (Katy)	X	X		X	X

Node	Name	Supply	Demand	Transit, Import/ Export	Underground Storage	Peakshaving Storage
66	S. TX	X	X			X
67	Offshore Texas	X				
68	NW TX	X	X			X
69	Garden Banks	X				
70	Green Canyon	X				
71	Eastern Gulf	X				
72	North British Columbia	X	X			X
73	South British Columbia		X			X
74	Caroline	X	X			X
75	Empress			X		
76	Saskatchewan	X	X			X
77	Manitoba	X	X			X
78	Dawn	X	X			X
79	Philadelphia		X			X
80	West Virginia	X	X		X	X
81	Eastern Canada Demand		X			X
82	Alliance Border Crossing			X		
83	Wind River Basin	X	X		X	
84	California Mexican Exports			X		
85	Whitehorse			X		
86	MacKenzie Delta	X				
87	South Alaska	X		X		
88	Central Alaska	X				
89	North Alaska	X				
90	Arctic	X				
91	Norman Wells	X				
92	Southwest VA	X	X		X	X
93	Southeast VA		X			X
94	North Carolina		X			X
95	South Carolina		X			X
96	North Florida	X	X			X
97	Arizona		X		X	X
98	Southwest Michigan	X	X		X	X
99	Northern Michigan	X	X		X	X
100	Malin Interchange			X		
101	Topock Interchange			X		
102	Ehrenberg Interchange			X		
103	SDG&E Demand		X			X
104	Eastern New York		X			X
105	New Jersey		X			X
106	Toronto		X			X
107	Carthage	X	X		X	X
108	Southwest Oklahoma	X	X		X	X
109	Northeast Oklahoma	X	X		X	X
110	Southeastern Oklahoma	X	X		X	X
111	Northern Arkansas	X	X		X	X

Node	Name	Supply	Demand	Transit, Import/ Export	Underground Storage	Peakshaving Storage
112	Southeast Missouri	X	X		X	X
113	Uinta/Piceance	X	X		X	X
114	South MS/AL	X	X		X	X

Figure 10-4 Gas Supply Regions Map

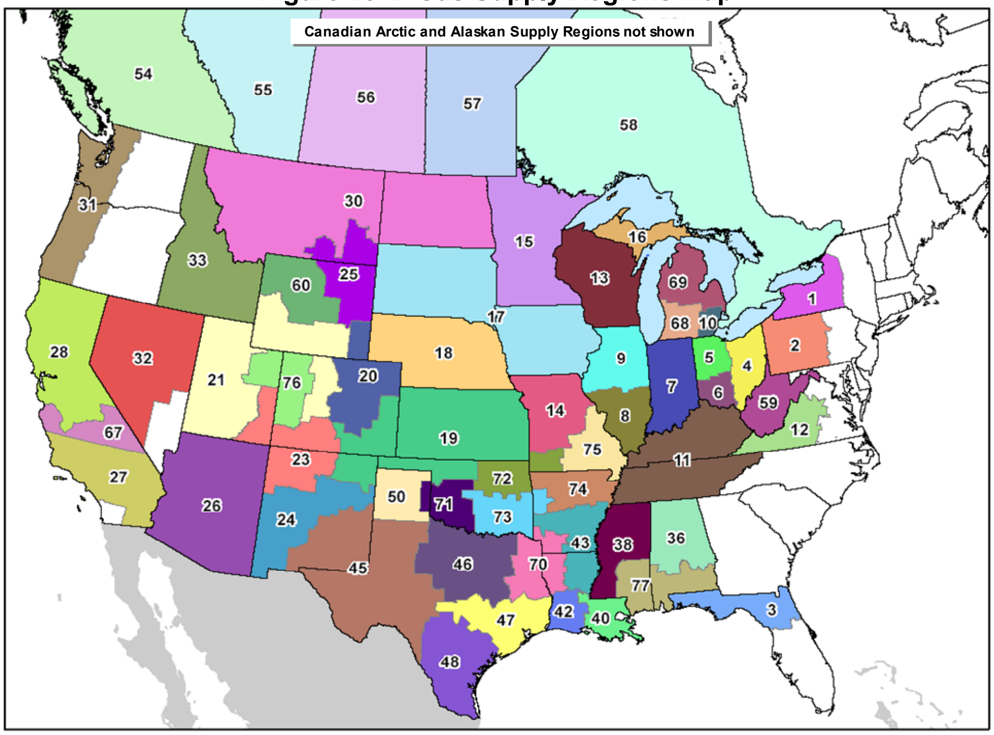
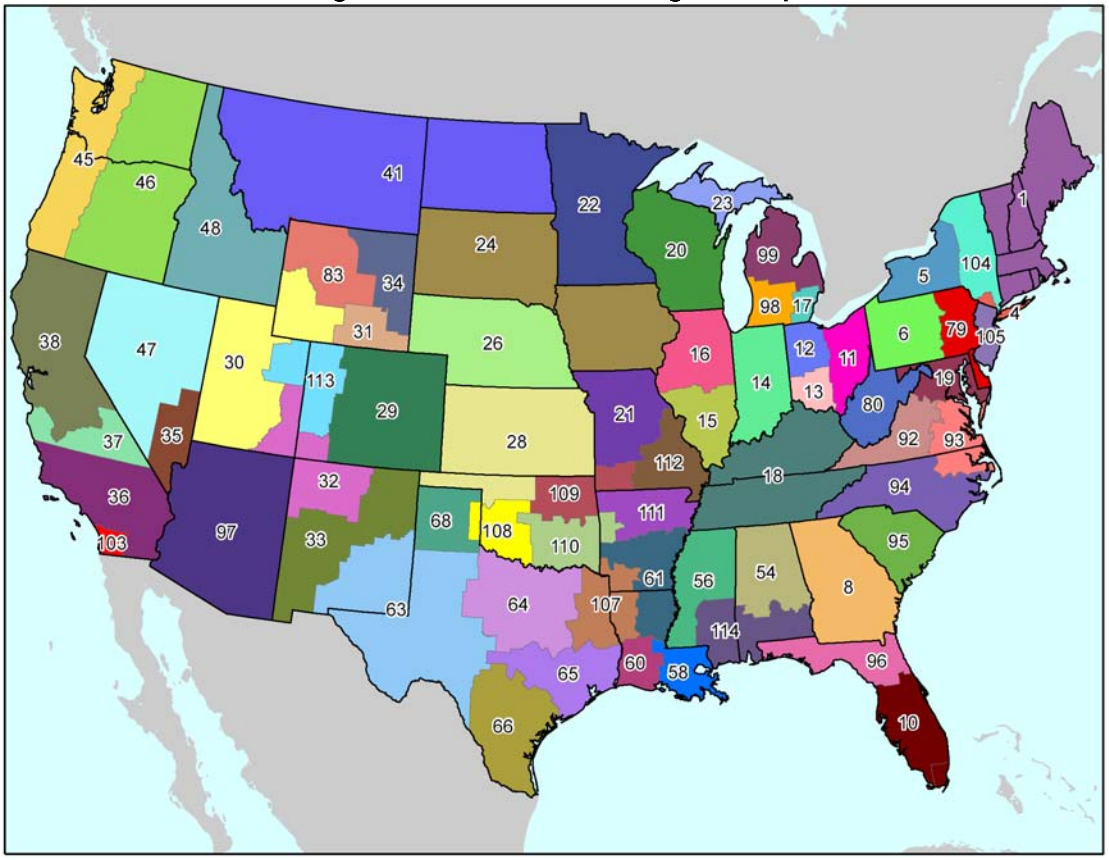


Table 10-2 List of Gas Supply Regions

Supply Region Number	Node Number	Region Name
1	5	Niagara
2	6	Leidy
3	96	Florida
4	11	East Ohio
5	12	Maumee/ Defiance
6	13	Lebanon
7	14	Indiana
8	15	South Illinois
9	16	North Illinois
10	17	Southeast Michigan
11	18	Tennessee/Kentucky
12	92	SW Virginia
13	20	Wisconsin
14	21	Northern Missouri
15	22	Minnesota
16	23	Crystal Falls
17	24	Ventura
18	26	Nebraska
19	28	Kansas
20	29	East Colorado
21	30	Opal
22	31	Cheyenne
23	32	San Juan Basin
24	33	EPNG/TW
25	34	North Wyoming
26	97	Arizona
27	36	SOCAL Area
28	38	PGE Area
29	39	California Offshore
30	41	Montana/ North Dakota
31	45	Pacific Northwest
32	47	North Nevada
33	48	Idaho
34	49	Eastern Canada Offshore
35	50	Atlantic Offshore
36	54	North Alabama
37	55	Alabama Offshore
38	56	North Mississippi
39	57	East Louisiana Shelf
40	58	Eastern Louisiana Hub
41	59	Viosca Knoll S./ Desoto Canyon/Mississippi Canyon
42	60	Henry Hub
43	61	North Louisiana Hub
44	62	Central and West Louisiana Shelf

Supply Region Number	Node Number	Region Name
45	63	Southwest Texas
46	64	Dallas/Fort Worth
47	65	E. TX (Katy)
48	66	S. TX
49	67	Offshore Texas
50	68	NW TX
51	69	Garden Banks
52	70	Green Canyon
53	71	Florida off-shore moratorium area
54	72	North British Columbia
55	74	Caroline
56	76	Saskatchewan
57	77	Manitoba
58	78	Dawn
59	80	West Virginia
60	83	Wind River Basin
61	86	McKenzie Delta
62	87	Southern Alaska
63	88	Central Alaska
64	89	Northern Alaska
65	90	Arctic
66	91	Norman Wells
67	37	Enhanced Oil Recovery Region
68	98	Southwest Michigan
69	99	Central Michigan
70	107	Carthage
71	108	Southwest Oklahoma
72	109	Northeast Oklahoma
73	110	Southeastern Oklahoma
74	111	Northern Arkansas
75	112	Southeast Missouri
76	113	Uinta/Piceance
77	114	South MS/AL

Figure 10-5 Gas Demand Regions Map



Natural gas pipeline network is modeled by 343 transmission links or segments (excluding pipeline connections with LNG nodes) that represent major interstate transmission corridors throughout North America (Figure 10-3). The pipeline corridors represent a group of interstate pipelines along the corridor. The list of key interstate pipelines by links is tabulated in Table 10-3. Each of the links has an associated discount curve (derived from GMM natural gas transportation module), which represents the marginal value of gas transmission on that pipeline segment as a function of the pipeline's load factor.[1] Starting year of operation and transmission capacity (in units of BBtu/day) are specified as inputs and the model allows for capacity expansions.

Table 10-3 List of Key Pipelines

Link	**Pipeline**
6 - 5	DOMINION TRANS (CNG)
6 - 5	COLUMBIA GAS TRANS CORP
5 - 6	NATIONAL FUEL GAS SUPPLY CO
11 - 6	DOMINION TRANS (CNG)
11 - 6	COLUMBIA GAS TRANS CORP
6 - 19	DOMINION TRANS (CNG)
6 - 79	TEXAS EASTERN TRANS CORP
6 - 79	TRANSCONTINENTAL GAS P L CO

[1] In this context "load factor" refers to the percentage of the pipeline capacity that is utilized at a given time.

Link	Pipeline
6 - 79	TENNESSEE GAS PIPELINE CO
80 - 6 80 - 6	COLUMBIA GAS TRANS CORP EQUITRANS INC
96 - 8	SOUTHERN NATURAL GAS CO
96 - 10	FLORIDA GAS TRANS CO
80 - 11	COLUMBIA GAS TRANS CORP
17 - 12	ANR PIPELINE CO
98 - 12	ANR PIPELINE CO
14 - 13	PANHANDLE EASTERN P L CO
98 - 14	TRUNKLINE GAS CO
16 - 15	NAT GAS P L CO OF AMERICA
16 - 20	ANR PIPELINE CO
16 - 98	ANR PIPELINE CO
78 - 17	BLUEWATER PIPELINE CO
99 - 17	MICHCON
18 - 80	COLUMBIA GAS TRANS CORP
18 - 92	EAST TENNESSEE NAT GAS CO
79 - 19 19 - 79 19 - 79	EASTERN SHORE NAT GAS CO TRANSCONTINENTAL GAS P L CO COLUMBIA GAS TRANS CORP
92 - 19	COLUMBIA GAS TRANS CORP
23 - 99	GREAT LAKES GAS TRANS LTD
106 - 23	GREAT LAKES GAS TRANS LTD
41 - 27	WILLISTON BASIN P L CO
28 - 29	COLORADO INTERSTATE GAS
68 - 28	COLORADO INTERSTATE GAS
31 - 30 31 - 30 30 - 31	COLORADO INTERSTATE GAS SOUTHERN STAR CENTRAL (WILLIAMS) WYOMING INTERSTATE CO
30 - 48	NORTHWEST PIPELINE CORP
113 - 30 113 - 32	NORTHWEST PIPELINE CORP NORTHWEST PIPELINE CORP
63 - 33 63 - 33 68 - 33	EL PASO NAT GAS CO TRANSWESTERN PIPELINE CO TRANSWESTERN PIPELINE CO
37 - 36	SOCAL GAS
37 - 38	PACIFIC GAS & ELECTRIC
40 - 41	NORTHWEST ENERGY
41 - 83	WILLISTON BASIN P L CO
73 - 43	TERASEN (BC GAS)
46 - 45	NORTHWEST PIPELINE CORP
46 - 48	NORTHWEST PIPELINE CORP
66 - 51	TENNESSEE GAS PIPELINE CO
51 - 66	TEXAS EASTERN TRANS CORP
54 - 114	TRANSCONTINENTAL GAS P L CO
58 - 56	GULF SOUTH (KOCH)
60 - 58	TRANSCONTINENTAL GAS P L CO

Link	Pipeline
60 - 58	SOUTHERN NATURAL GAS CO
60 - 58	FLORIDA GAS TRANS CO
60 - 58	TENNESSEE GAS PIPELINE CO
60 - 58	TEXAS EASTERN TRANS CORP
60 - 58	GULF SOUTH (KOCH)
60 - 65	NAT GAS P L CO OF AMERICA
61 - 107	CENTERPOINT ENERGY (RELIANT)
64 - 63	TXU LONESTAR GAS PIPELINE
64 - 63	EPGT TEXAS PIPELINE (VALERO)
65 - 63	OASIS
66 - 63	EPGT TEXAS PIPELINE (VALERO)
68 - 63	TRANSWESTERN PIPELINE CO
63 - 68	EL PASO NAT GAS CO
63 - 97	EL PASO NAT GAS CO
65 - 64	TXU FUEL CO
65 - 64	TXU LONESTAR GAS PIPELINE
108 - 68	NAT GAS P L CO OF AMERICA
108 - 68	EL PASO NAT GAS CO
68 - 108	ANR PIPELINE CO
106 - 78	UNION GAS
102 - 84	BAJA NORTE
99 - 98	ANR PIPELINE CO
99 - 98	MICHIGAN GAS STORAGE
101 - 102	EL PASO NAT GAS CO

Natural gas storage is modeled by 180 underground and LNG peak shaving[2] storage facilities that are linked to individual nodes. The underground storage is grouped into three categories based on storage "Days Service"[3]: (1) 20-day for high deliverability[4] storage such as salt caverns, (2) 80-day for depleted[5] and aquifer[6] reservoirs, and (3) over 80 days mainly for depleted reservoirs. Figure 10-6 shows natural gas storage facility node map. The level of gas storage withdrawals and injections are calculated within the supply and demand balance algorithm based on working gas[7] levels, gas prices, and extraction/injection rates and costs. Starting year of

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[2] LNG peak shaving facilities supplement deliveries of natural gas during times of peak periods. LNG peak shaving facilities have a regasification unit attached, but may or may not have a liquefaction unit. Facilities without a liquefaction unit depend upon tank trucks to bring LNG from nearby sources.

[3] "Days Service" refers to the number of days required to completely withdraw the maximum working gas inventory associated with an underground storage facility.

[4] High deliverability storage is depleted reservoir storage facility or Salt Cavern storage whose design allows a relatively quick turnover of the working gas capacity.

[5] A gas or oil reservoir that is converted for gas storage operations. Its economically recoverable reserves have usually been nearly or completely produced prior to the conversion.

[6] The underground storage of natural gas in a porous and permeable rock formation topped by an impermeable cap rock, the pore space of which was originally filled with water.

[7] The term "working gas" refers to natural gas that has been injected into an underground storage facility and stored therein temporarily with the intention of withdrawing it. It is distinguished from "base (or cushion) gas" which refers to the volume of gas that remains permanently in the storage

operation and working gas capacity (in units of BBtu) are specified as inputs and the model allows for capacity expansions. The location of the storage facilities is shown in Figure 10-6.

Natural gas prices are market clearing prices derived from the supply and demand balance at each of the model's nodes for each segment of IPM's electricity sector's seasonal load duration curve (LDC). On the supply-side, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization. Prices are also affected by the "pipeline discount" curves discussed earlier, which represent the marginal value of gas transmission as a function of a pipeline's load factor and result in changes in basis differential. On the demand-side, the price/quantity relationship is represented by demand curves that capture the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes and yields market clearing prices determined by the specific shape of the supply and demand curves at each node.

10.2.1 Note on the Modeling Time Horizon and Pre- and Post-2030 Input Assumptions

The time horizon of previous EPA IPM base cases extended no further than 2030. This made possible a detailed bottom-up development of natural gas assumptions from available data sources. To support analysis of climate change policies, which have a longer time horizon than previously analyzed policies for conventional air pollutants, the time horizon of EPA's new Base Case v.4.10 extends to 2050. The same detailed bottom-up approach that was employed previously is employed out to 2030. Beyond 2030, where detailed data is not readily available, various technically plausible simplifying assumptions were made. For example, natural gas demand growth from 2030 to 2050 for the non-power sectors (i.e. residential, commercial, and industrial) is assumed to be the same as the level of growth from 2020 to 2030. Resource growth assumptions (for resource appreciation) that were applied for pre-2030 are extended beyond 2030. Post 2030 price projections for crude oil and natural gas liquid[8] (NGL) are assumed to be flat at 2030 price levels. The pre-2030 price projections were adapted from AEO 2010.

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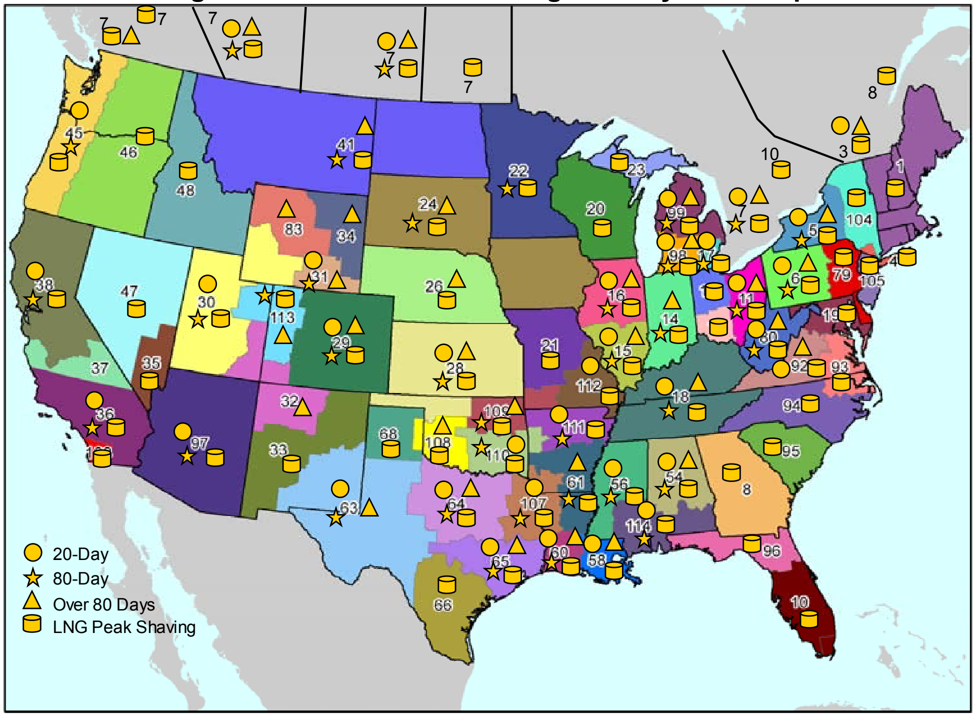
reservoir in order to maintain adequate pressure and deliverability rates throughout the withdrawal season.

[8] Those hydrocarbons in natural gas that are separated from the gas as liquids in gas processing or cycling plants. Generally such liquids consist of propane and heavier hydrocarbons and are commonly referred to as lease condensate, natural gasoline, and liquefied petroleum gases.

Figure 10-6 Natural Gas Storage Facility Node Map



10.3 Resource Characterization and Economic Evaluation

The GMM Hydrocarbon Supply Model (HSM) provides data related to resource characterization and economic evaluation for use in the IPM natural gas module. The current section describes data sources and methods used in the HSM to characterize the North American natural gas resource base. This section concludes with a description of how the HSM resource characterization is used in the EPA Base Case v.4.10 gas module. The next section (i.e., Section 10.4) describes the economic evaluation procedures applied to Exploration and Development (E&D) activities in the HSM and various constraints affecting E&D activities.

The HSM was designed for the simulation, forecasting and analysis of natural gas, crude oil and natural gas liquids supply and cost trends in the United States and Canada. The HSM includes a highly detailed description of both the undiscovered and discovered resources in the US and Canada. The resource base is described on a field-by-field basis. The individual fields are characterized by type (i.e., oil or gas), size, and location. Location is defined both geographically and by depth. The HSM is a process-engineering model with a very detailed representation of potential gas resources and the technologies with which those resources can be proven[9] and produced. The degree and timing by which resources are proven and produced are determined in the model through discounted cashflow analyses of alternative investment options and behavioral assumptions in the form of inertial and cashflow constraints, and the logic underlying producers' market expectations (e.g., their response to future gas prices).

Supply results from the HSM model include undeveloped resource accounting and detailed well, reserve addition, decline rate, and financial results. These results are utilized to provide estimates

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[9] The term “proven” refers to the estimation of the quantities of natural gas resources 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. Among the factors considered are drilling results, production, and historical trends. Proven reserves are the most certain portion of the resource base.

of base year economically recoverable natural gas resources and remaining reserves as a function of E&D cost for the 77 supply regions in the IPM natural gas module. The HSM also provides other data such as the level of remaining resource that could be discovered and developed in a year, exploration and development drilling requirements, production operation and maintenance (O&M) cost, resource share of crude oil and natural gas liquids, natural gas reserves to production ratio, and natural gas requirement for lease and plant use.[10]

10.3.1 Resource and Reserves[11] Assessment

Data sources: The HSM uses the U.S. Geological Survey (USGS), Minerals Management Service (MMS), and Canadian Gas Potential Committee (CGPC) play-level[12] resource assessments as the starting point for the new field/new pool[13] assessments. Beyond the resource assessment data, ICF has access to numerous databases that were used for the HSM model development and other analysis. Completion-level production is based on IHS Energy completion level oil and gas production databases for the U.S. and Canada. The U.S. database contains information on approximately 300,000 U.S. completions. A structured system is employed to process this information and add certain ICF data (region, play, ultimate recovery, and gas composition) to each record. ICF also performs extensive quality control checks using other data sources such as the MMS completion and production data for Outer Continental Shelf (OCS) areas and state production reports.

In the area of unconventional gas[14], ICF has worked for many years with the Gas Research Institute (GRI)/Gas Technology Institute (GTI) to develop a database of tight gas, coalbed methane, and Devonian Shale reservoirs in the U.S. and Canada. Along with USGS assessments of continuous plays, the database was used to help develop the HSM's "cells", which represent resources in a specific geographic area, characterizing the unconventional resource in each basin, historical unconventional reserves estimates and typical decline curves.[15]

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[10] As discussed more fully in Section 10.4, natural gas for "lease and plant use" refers to the gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and as fuel in gas processing plants.

[11] When referring to natural gas a distinction is made between "resources" and "reserves." "Resources" are concentrations of natural gas that are or may become of potential economic interest. "Reserves" are that part of the natural gas resource that has been fully evaluated and determined to be commercially viable to produce.

[12] A "play" refers to a set of known or postulated natural gas (or oil) accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type.

[13] A "pool" is a subsurface accumulation of oil and other hydrocarbons. Pools are not necessarily big caverns. They can be small oil-filled pores. A "field" is an accumulation of hydrocarbons in the subsurface of sufficient size to be of economic interest. A field can consist of one or more pools.

[14] Unconventional gas refers to natural gas found in geological environments that differ from conventional hydrocarbon traps. It includes: (a) "tight gas," i.e., natural gas found in relatively impermeable (very low porosity and permeability) sandstone and carbonate rocks; (b) "shale gas," i.e., natural gas in the joints, fractures or the matrix of shales, the most prevalent low permeability low porosity sedimentary rock on earth; and (c) "coalbed methane," which refers to methane (the key component of natural gas) found in coal seams, where it was generated during coal formation and contained in the microstructure of coal. Unconventional natural gas is distinguished from conventional gas which is extracted using traditional methods, typically from a well drilled into a geological formation exploiting natural subsurface pressure or artificial lifting to bring the gas and associated hydrocarbons to the wellhead at the surface.

[15] A decline curve is a plot of the rate of gas production against time. Since the production rate decline is associated with pressure decreases from oil and gas production, the curve tends to smoothly decline from a high early production rate to lower later production rate. Exponential,

ICF has recently revised the unconventional gas resource assessments based on new gas industry information on the geology, well production characteristics, and costs. The new assessments include major shale units such as the Fort Worth Barnett Shale, the Marcellus Shale, the Haynessville Shale, and Western Canada shale plays. ICF has built up a database on gas compositions in the United States and has merged that data with production data to allow the analysis of net versus raw gas production.[16]

In Canada, gas composition data are obtained from provincial agencies. These data were used to develop dry gas[17] production/reserves by region and processing costs in the HSM and to characterize ethane rejection[18] by regions. Information on oil and gas fields and pools in the U.S. come originally from Dwight's Energydata (now IHS Energy) TOTL reservoir database. ICF has made extensive modifications to the database during the creation of the Gas Information System (GASIS) database for the U.S. Department of Energy (DOE) and other projects. Field and reservoir data for Canada comes from the provincial agency databases. These data are used to estimate the number and size of undiscovered fields or pools and their rate of discovery per increment of exploratory drilling. Additional data were obtained from the Significant Field Data Base of NRG Associates.

Methodology and assumptions: Resources in the HSM model are divided into three general categories: new fields/new pools, field appreciation, and unconventional gas. The methodology for resource characterization and economic evaluation differs for each.

Conventional resource – new fields/new pools: The modeling of conventional resource is based on a modified "Arps Roberts" equation[19] to estimate the rate at which new fields are discovered. The fundamental theory behind the find-rate methodology is that the probability of finding a field is proportional to the field's size as measured by its area extent, which is highly correlated to the field's level of reserves. For this reason, larger fields tend to be found earlier in the discovery process than smaller fields. Finding that the original Arps-Roberts equation did not replicate historical discovery patterns for many of the smaller field sizes, ICF modified the equation to improve its ability to accurately track discovery rates for mid- to small-size fields. Since these are the only fields left to be discovered in many mature areas of the U.S. and Western Canada Sedimentary Basin (WCSB), the more accurate find-rate representation is an important component in analyzing the economics of exploration activity in these areas. An economic evaluation is made in the model each year for potential new field exploration programs using a standard discounted after-tax cash flow (DCF) analysis. This DCF analysis takes into account how many fields of each type are expected to be found and the economics of developing each.

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harmonic, and hyperbolic equations are typically used to represent the decline curve.

[16] Raw gas production refers to the volumes of natural gas extracted from underground sources, whereas net gas production refers to the volume of purified, marketable natural gas leaving the natural gas processing plant.

[17] Natural gas is a combustible mixture of hydrocarbon gases. Although consisting primarily of methane, the composition of natural gas can vary widely to include propane, butane, ethane, and pentane. Natural gas is referred to as 'dry' when it is almost pure methane, having had most of the other commonly associated hydrocarbons removed. When other hydrocarbons are present, the natural gas is called 'wet'.

[18] Ethane rejection occurs when the ethane component in the natural gas stream is not recovered in a gas processing plant but left in the marketable natural gas stream. Ethane rejection is deployed when the value of ethane is worth more in the gas stream than as an a separate commodity or as a component of natural gas liquids (NGL), which collectively refers to ethane, propane, normal butane, isobutane, and pentanes in processed and purified finished form. Information that characterizes ethane rejection by region can play a role in determining the production level and cost of natural gas by region.

[19] "Arps-Roberts equation" refers to the statistical model of petroleum discovery developed by J. J. Arps, and T. G. Roberts, T. G.,in the 1950's.

Conventional resource – field appreciation: The model maintains inventories of potential resources that can be proved from already discovered fields. These inventories are referred to as appreciation, growth-to-known or "probables." As the model simulation proceeds, these probables inventories are drawn down as the resources are proved. At the same time, the inventories of probables are increased due to future year appreciation of new fields that are added to the discovered fields' data set during the model simulation.

Unconventional resource: The Enhanced Recovery Module (or ERM) within the HSM, covers that portion of the resource base which falls outside the scope of the "conventional" oil and gas field discovery process dealt with elsewhere in the model. The ERM includes coalbed methane, shale gas, and tight gas. These resources generally correspond to the "continuous plays" designated by the USGS in its resource assessments. The ERM is organized by "cells", which represent resources in a specific geographic area. A cell can represent any size of area ranging from the entire region/depth interval to a single formation in a few townships of a basin. Each cell is evaluated in the model using the same discounted cashflow analysis used for new and old field investments. The ERM cells also are subject to the inertial and cashflow constraints affecting the other types of investment options in the model. The model reports total wells drilled, reserve additions, production, and dollars invested for each type of ERM cell (e.g., coalbed methane) within a region.

10.3.2 Frontier Resources (Alaska and Mackenzie Delta)

Besides the three general categories of resources described above, the handling of frontier resources in the HSM is worth noting. Frontier resources such as Alaska North Slope and Mackenzie Delta are subject to similar resource assessment and economic evaluation procedures as applied to other regions. Results from HSM simulation for the two frontier regions can be seen in Table 10-4. It shows an undiscovered resource potential is 126.8 Tcf for Alaska North Slope and 32.9 Tcf for Mackenzie Delta and remaining gas reserves of 25.5 Tcf and 0.4 Tcf for Alaska North Slope and Mackenzie Delta, respectively. However, unlike other regions, the resources from these regions are stranded to date due to lack of effective commercial access to markets. In fact, 6-8 Bcf/d of gas that is currently produced as part of the oil activities in the Alaska North Slope is re-injected back into the Slope's oil reservoirs as part of the pressure maintenance programs. Several development proposals have been put forward for bringing this gas to market in order to realize the long-held goal of monetizing the Alaska North Slope and Mackenzie Delta gas.

In developing the gas resource assumptions for EPA Base Case v.4.10, two gas pipeline projects were identified for bringing the two frontier gas supply resources to the markets in the U.S. and Canada. A diagnostic run was made with both potential pipeline projects turned on, letting the model decide the starting year of the projects and subsequent pipeline capacity expansions. Analysis of pipeline capacities and flows indicated that the Alaska gas pipeline project would be feasible starting from 2035, but the Mackenzie Delta pipeline project would not be feasible at all due to relatively low pipeline flows. These were the assumptions used for EPA Base Case v.4.10.

Table 10-4 U.S. and Canada Natural Gas Resources and Reserves

Region	End of Year 2008		End of Year 2010	
	Undiscovered Dry Gas Resource (Tcf)	Dry Gas Reserves (Tcf)	Undiscovered Dry Gas Resource (Tcf)	Dry Gas Reserves (Tcf)
Lower 48 Onshore Non Associated	1,629.0	208.5	1,616.2	208.0
Conventional	313.3	50.1	306.6	50.0
Northeast	15.4	3.8	15.0	3.8
Gulf Coast	133.9	16.4	131.5	16.4
Midcontinent	54.4	11.2	52.7	11.2

Region	End of Year 2008		End of Year 2010	
	Undiscovered Dry Gas Resource (Tcf)	Dry Gas Reserves (Tcf)	Undiscovered Dry Gas Resource (Tcf)	Dry Gas Reserves (Tcf)
Southwest	19.2	5.6	18.6	5.6
Rocky Mountain	84.0	10.7	82.6	10.7
West Coast	6.4	2.4	6.2	2.3
Shale Gas	921.2	38.5	917.2	38.4
Northeast	254.8	3.5	254.4	3.5
Gulf Coast	433.1	13.5	431.6	13.4
Midcontinent	133.9	10.9	132.9	10.8
Southwest	61.3	10.7	60.3	10.6
Rocky Mountain	37.9	-	37.7	-
West Coast	0.3	-	0.3	-
Coalbed Methane	73.9	20.5	73.1	20.4
Northeast	9.5	2.0	9.5	2.0
Gulf Coast	4.3	1.2	4.2	1.2
Midcontinent	9.6	2.2	9.5	2.2
Southwest	-	-	-	-
Rocky Mountain	49.8	15.1	49.3	15.0
West Coast	0.7	-	0.6	-
Tight Gas	320.7	99.5	319.2	99.2
Northeast	33.7	6.6	34.0	6.6
Gulf Coast	59.6	28.9	58.2	28.9
Midcontinent	4.6	7.5	4.6	7.5
Southwest	6.1	15.2	5.9	15.1
Rocky Mountain	205.1	41.2	204.9	41.1
West Coast	11.5	-	11.6	-
Lower 48 Offshore Non Associated	137.1	10.5	136.3	10.5
Lower 48 Associated-Dissolved Gas	145.1	17.9	143.5	17.9
Total Lower 48	1,911.2	237.0	1,895.9	236.3
Alaska	153.6	35.2	153.3	35.2
Alaska North Slope	126.8	25.2	126.8	25.2
Alaska - Other	26.8	9.9	26.5	9.9
Total U.S.	2,064.8	272.1	2,049.2	271.5
Canada Non Associated	667.9	56.7	667.3	56.5
Conventional	121.4	43.6	119.6	43.5
Shale Gas	508.8	0.5	511.1	0.5
Coalbed Methane	27.4	12.5	26.7	12.5
Tight Gas	10.3	-	9.9	-
Canada Associated-Dissolved Gas	8.1	2.7	8.0	2.7
Eastern Canada Offshore	71.8	2.5	71.6	2.5
MacKenzie Delta	32.9	0.4	32.9	0.4
Total Canada	780.8	62.3	779.8	62.1

10.3.3 Use of the HSM resource and reserves data in EPA Base Case using IPM v.4.10 Natural Gas Module

The base year for the integrated gas-electricity module in EPA Base Case using IPM v.4.10 is 2012. Having a base year in the future has implications on how the model is run and how the gas reserves and resources data are set up. The IPM run begins with a gas module only run for year 2011 to provide end of year (EOY) 2011 reserves and resources as the starting point for the integrated run from 2012 onward. This in turn requires the reserves and resources data to be provided for the EOY 2010. Since the data from the HSM are as of EOY 2008, a two-year production forecast needs to be conducted to estimate the EOY 2010 gas resources and reserves. This production forecast is done using the GMM with the EPA Base Case assumptions. In the future if an IPM sensitivity analysis case is performed whose assumptions are likely to have a significant impact on gas reserves and resources in the 2009-2010 timeframe, the HSM projection of EOY 2010 gas resources and reserves may have to be re-run.

The last two columns in Table 10-4 give a snapshot of the starting natural gas resource and reserve assumptions that were provided by HSM to EPA Base Case v.4.10 for EOY 2010. In this table, undiscovered resources represent the economic volume of dry gas that could be discovered and developed with current technology through exploration and development at a specified maximum wellhead gas price. The reserves are remaining dry gas volumes to be produced from existing developed fields. For EPA Base Case the maximum wellhead price for the resource cost curves is capped at around $14/MMBtu (in real 2007 dollars). The ultimate potential undiscovered resources available are actually higher than those presented in Table 10-4 but it would cost more than $14/MMBtu to recover them. (It is important to note that this price is for wet[20] gas at the wellhead in the production nodes and is found to be high enough to cover the range of wellhead prices for EPA scenarios. The dry gas price at the receiving nodes can be higher than $14/MMBtu which depends on the share of dry gas, lease and plant use, gas processing cost, production O&M cost, and pipeline transportation costs.) The approach used in the HSM to derive these costs is described more fully in section 10.4 below.

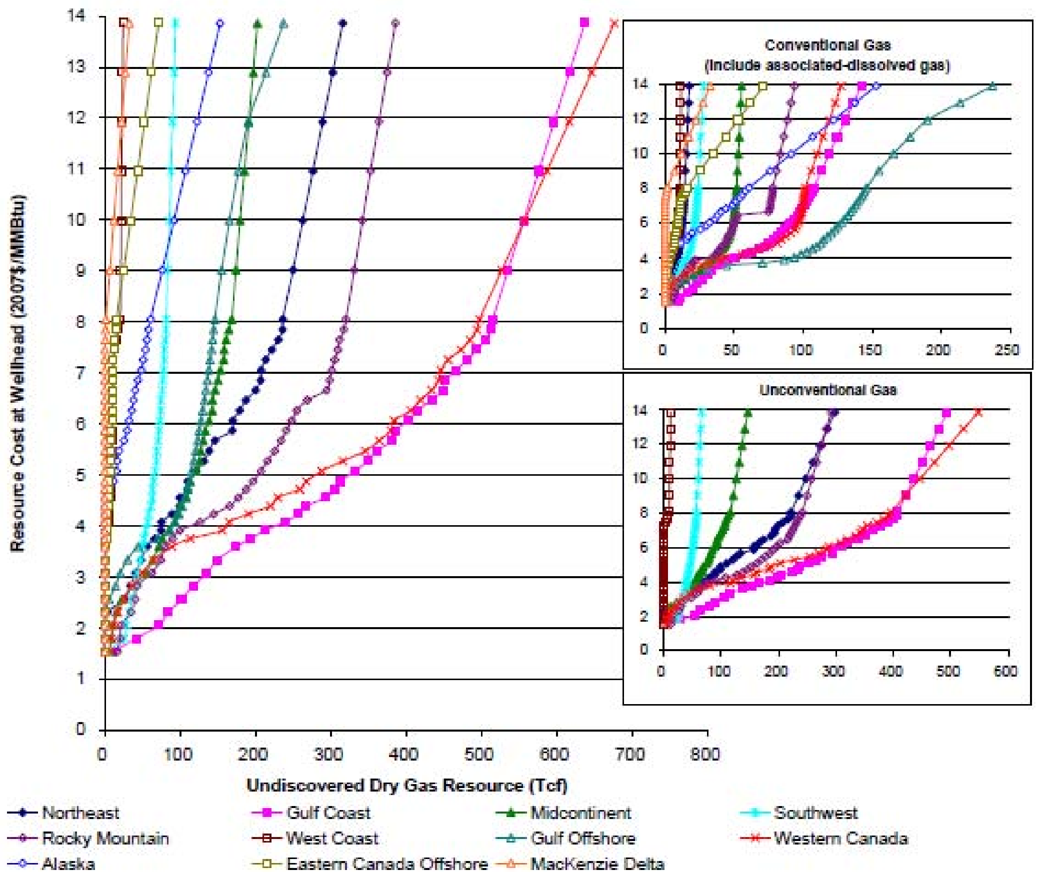
Since the new IPM natural gas module differentiates conventional gas from unconventional gas, these are shown separately in Table 10-4. The conventional gas is subcategorized into non-associated gas from gas fields and associated gas[21] from oil fields. The unconventional gas is subdivided into coalbed methane, shale gas, and tight gas. The U.S. and Canada natural gas undiscovered resources and remaining reserves as of EOY 2008 and their estimates for the EOY 2010 are also shown in Table 10-4.

Figure 10-7 presents resource cost curves for the EOY 2010 initializing gas assumptions that the HSM provides for EPA Base Case v.4.10. The cost curves show the recoverable resources at different price levels. Separate resource cost curves are shown for key regions as well as for conventional and unconventional gas. The recoverable resources shown at maximum wellhead prices in these graphs are those tabulated in Table 10-4 under EOY 2010 column. The y-axis of the resource cost curves shows the cost at the wellhead of bringing the volume of undiscovered resource indicated on the x-axis into the reserves category. Figure 10-8 diagrams the exploration & development and production processes and the associated costs required to bring undiscovered resource into reserves and production.

[20] A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in porous rock formations at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentane. Typical nonhydrocarbon gases that may be present in reservoir natural gas are water vapor, carbon dioxide, hydrogen sulfide, nitrogen and trace amounts of helium.

[21] Associated gas refers to natural gas that is produced in association with crude oil production, whereas non-associated gas is natural gas that is not in contact with significant quantities of crude oil in the reservoir.

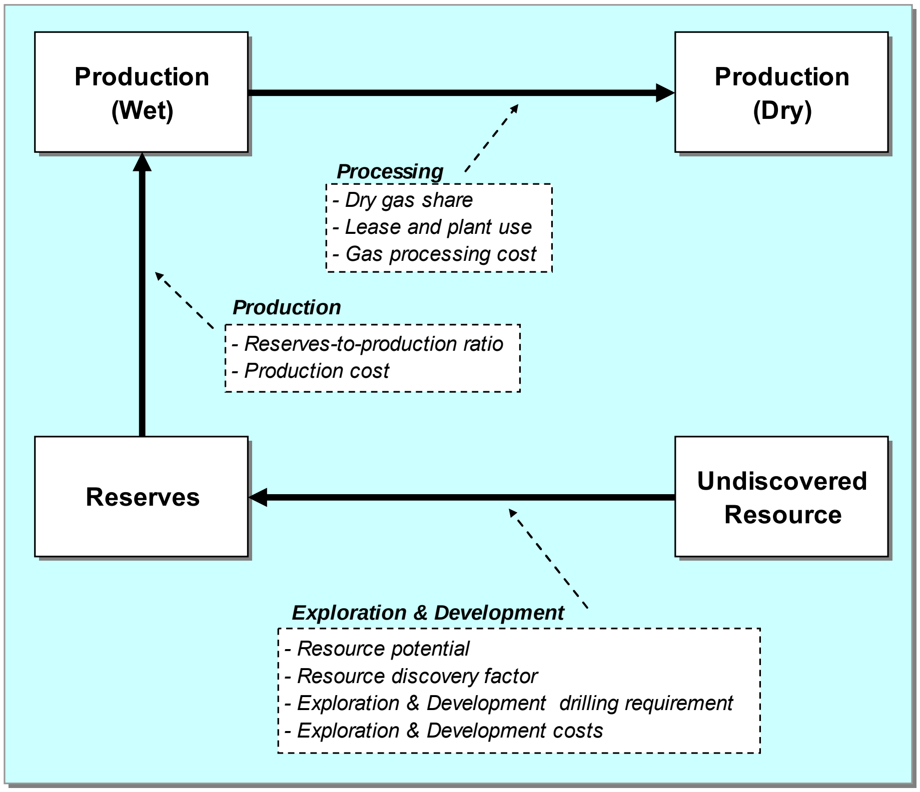
Figure 10-7 Resource Cost Curves at the End of Year 2010



10.3.4 Undiscovered Resource Appreciation

Undiscovered resource appreciation is additional resources from hydrocarbon plays that were not included in the resource base estimates. It differs from field appreciation or reserves appreciation category discussed above which comes from already discovered fields. Natural gas from shales, coal seams, offshore deepwater, and gas hydrates may not be included in the resource base assessments due to lack of knowledge and technology to economically recover the resource. As new technology becomes available, these untapped resources can be produced economically in the future. One example is the advancements in horizontal drilling and hydraulic fracture technologies to produce gas from shale formations. For EPA Base Case, the undiscovered gas resource is assumed to grow at 0.2% per year for conventional gas and 0.75% per year for unconventional gas. The EOY 2010 undiscovered resources in Table 10-4 and Figure 10-7 include resource appreciation in 2009 and 2010.

Figure 10-8 Exploration & Development and Production Processes and Costs to Bring Undiscovered Resource into Reserves and Production



10.4 Exploration, Development, and Production Costs and Constraints

10.4.1 Exploration and Development Cost

Exploration and development (E&D) cost or resource cost is the expenditure for activities related to discovering and developing hydrocarbon resources. The E&D cost for natural gas resources is a function of many factors such as geographic location, field type, size, depth, exploratory success rates, and platform, drilling and other costs. The HSM contains base year cost for wells, platforms, operating costs and all other relevant cost items. In addition to the base year costs, the HSM contains cost indices that adjust costs over time. These indices are partly a function of technology drivers such as improved exploratory success rates, cost reductions in platform, drilling and other costs, improved recovery per well, and partly a function of regression-based algorithms that relate cost to oil and gas prices and industry activity. As oil and gas prices and industry activity increase, the cost for seismic, drilling & completion services, casing and tubing and lease equipment goes up.

Other technology drivers affect exploratory success rates and reduce the need to drill exploratory wells. A similar adjustment is made to take into account changes over time in development success rates, but the relative effect is much smaller because development success rates are already rather high. The technology drivers that increase recovery per well are differentiated in the HSM by region and by type of gas. Generally, the improvements are specified as being greater for unconventional gas because their recovery factors are much lower than those of conventional gas.

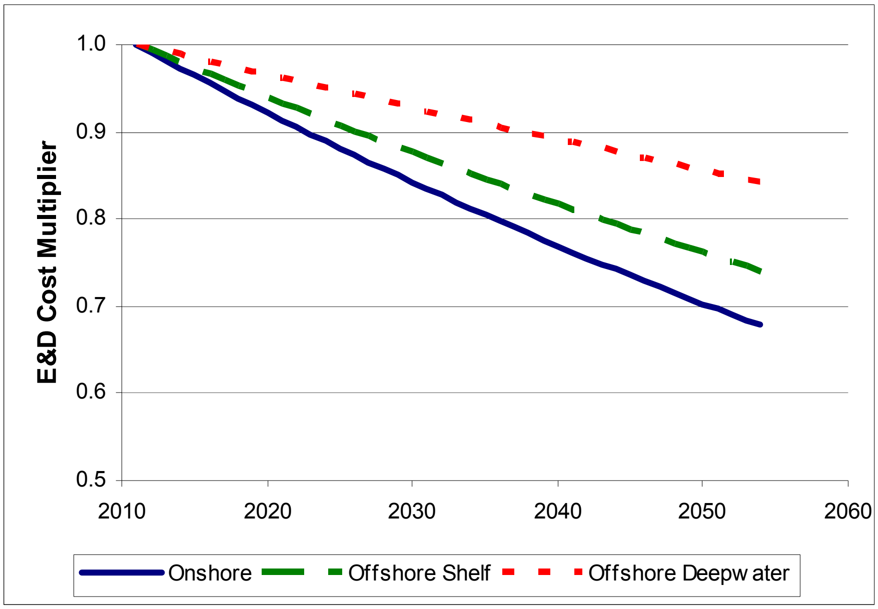
The HSM model provides estimates of E&D cost and the level of economically viable gas resource by region as a function of E&D cost. The HSM increased recovery as a function of technology improvement by region is converted to E&D and production technology improvement over time in the form of cost reduction factors by onshore, offshore shelf, and offshore deepwater as shown in

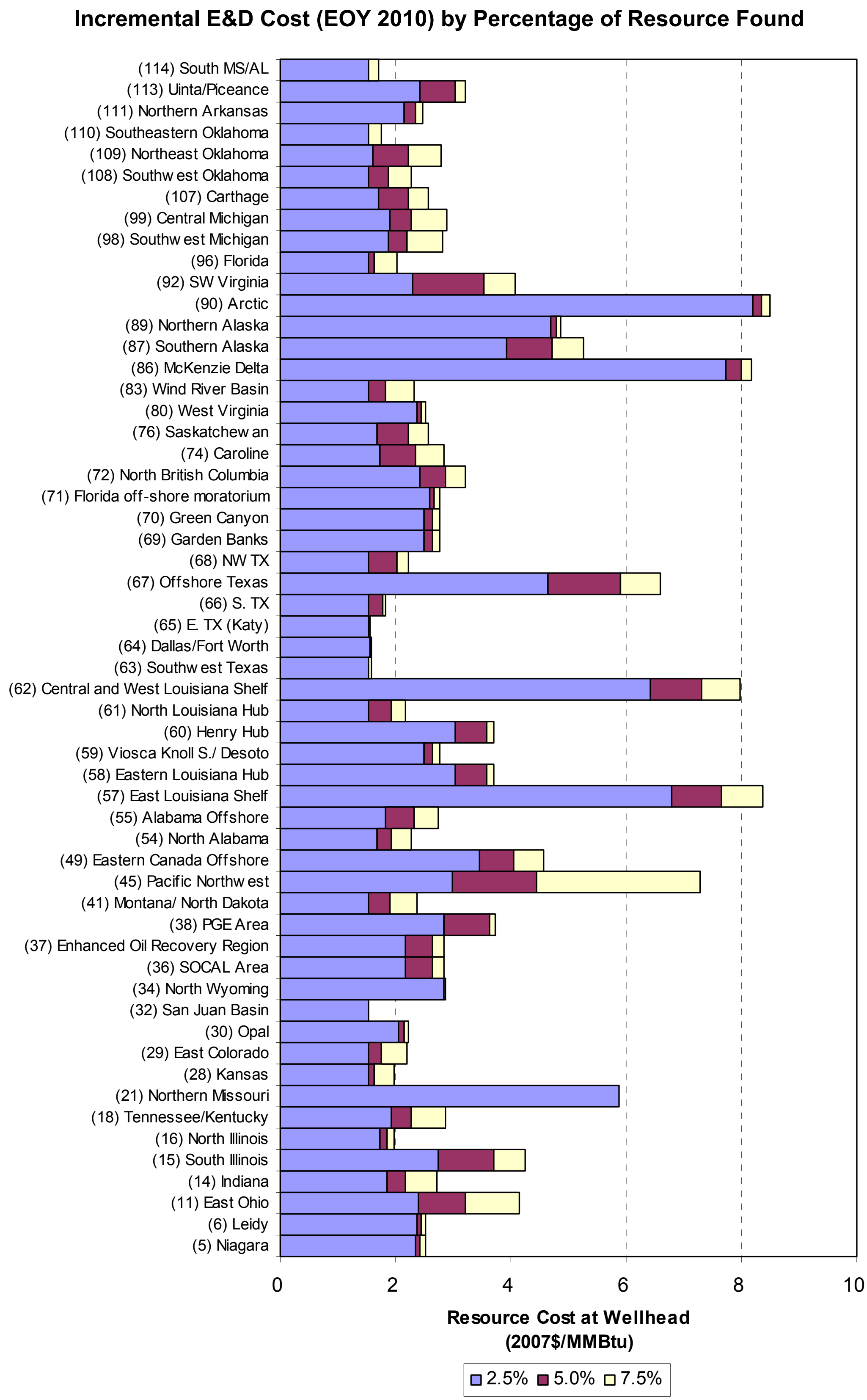
Figure 10-9. The average cost reduction factors for onshore, offshore shelf, and offshore deepwater E&D activities are -0.9% per year, -0.7% per year, and -0.4% per year, respectively. These factors are predominantly affected by the level of E&D investments in the regions. The expected aggressive onshore E&D activities to find and produce unconventional gas resources, such as shale gas, will lead to more research in horizontal drilling and hydraulic fracturing technologies to improve productions and lower the costs. This is reflected in higher cost reduction factors for the onshore regions.

Figure 10-10 shows E&D cost needed to discover and develop 2.5%, 5%, and 7.5% of the remaining undiscovered resource in 2011 by natural gas supply region.

Figure 10-9 E&D and Production Technology Improvement Factor

Figure **10-10**




Incremental E&D Cost (EOY 2010) by Percentage of Resource Found
(114) South MS/AL
(113) Uinta/Piceance
(111) Northern Arkansas
(110) Southeastern Oklahoma
(109) Northeast Oklahoma
(108) Southw est Oklahoma
(107) Carthage
(99) Central Michigan
(98) Southw est Michigan
(96) Florida
(92) SW Virginia
(90) Arctic
(89) Northern Alaska
(87) Southern Alaska
(86) McKenzie Delta
(83) Wind River Basin
(80) West Virginia
(76) Saskatchew an
(74) Caroline
(72) North British Columbia
(71) Florida off-shore moratorium
(70) Green Canyon
(69) Garden Banks
(68) NW TX
(67) Offshore Texas
(66) S. TX
(65) E. TX (Katy)
(64) Dallas/Fort Worth
(63) Southw est Texas
(62) Central and West Louisiana Shelf
(61) North Louisiana Hub
(60) Henry Hub
(59) Viosca Knoll S./ Desoto
(58) Eastern Louisiana Hub
(57) East Louisiana Shelf
(55) Alabama Offshore
(54) North Alabama
(49) Eastern Canada Offshore
(45) Pacific Northw est
(41) Montana/ North Dakota
(38) PGE Area
(37) Enhanced Oil Recovery Region
(36) SOCAL Area
(34) North Wyoming
(32) San Juan Basin
(30) Opal
(29) East Colorado
(28) Kansas
(21) Northern Missouri
(18) Tennessee/Kentucky
(16) North Illinois
(15) South Illinois
(14) Indiana
(11) East Ohio
(6) Leidy
(5) Niagara
0
2
4
6
8
10
Resource Cost at Wellhead
(2007$/MMBtu)
2.5%
5.0%
7.5%

10.4.2 Resource Discovery and Drilling Constraints

As mentioned above the simulation in HSM also provides other data such as resource discovery factors which describe the maximum share of remaining undiscovered resource that could be discovered and developed in a year and drilling requirements which describe the drilling required for successful exploration and development. These two parameters are constraints to the development of the resource and their values are not time dependent. The resource discovery constraint is the same for all regions and is assumed to be 4% of the remaining undiscovered resource (column 4 in Table 10-5). The drilling requirement constraint (column 5 in Table 10-5) is 10,000 feet for every billion cubic feet of incremental resource discovered for onshore and 2,500 feet/Bcf for offshore.

Table 10-5 Exploration and Development Assumptions for EPA Base Case v.4.10

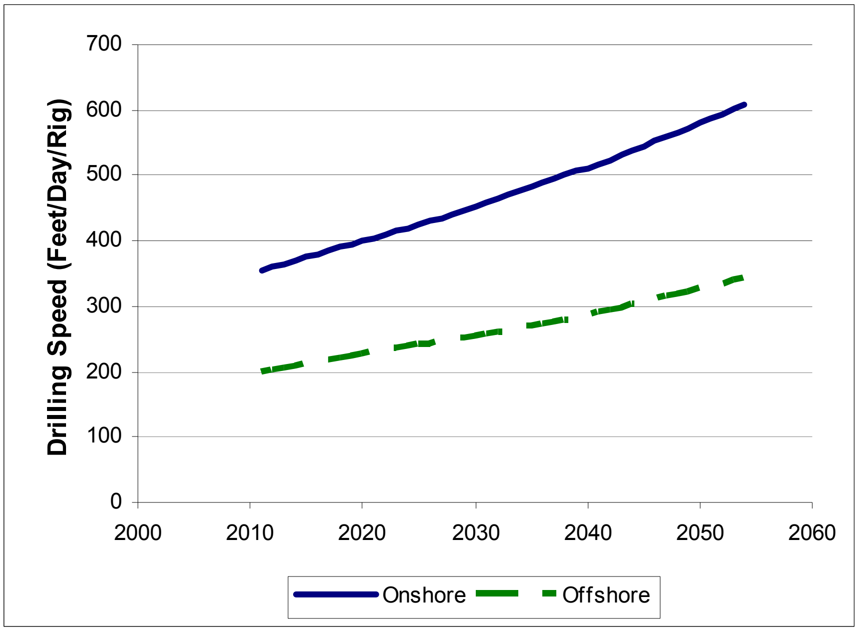
Region	Fraction of Hydrocarbons that are Natural Gas Liquids (NGLs) (Fraction)	Fraction of Hydrocarbons that are Crude Oil (Fraction)	Max Share of Resources that can be Developed per Year (Fraction)	Exploration, Development Drilling Required (Ft/Bcf)	Lease and Plant Use (Fraction)
(5) Niagara	0.01	0.04	0.04	10,000	0.05
(6) Leidy	0.00	0.05	0.04	10,000	0.03
(11) East Ohio	0.00	0.23	0.04	10,000	0.01
(14) Indiana	0.05	0.81	0.04	10,000	0.02
(15) South Illinois	0.10	0.10	0.04	10,000	0.30
(16) North Illinois	0.10	0.10	0.04	10,000	0.30
(18) Tennessee/Kentucky	0.12	0.10	0.04	10,000	0.04
(21) Northern Missouri	0.15	0.46	0.04	10,000	0.04
(28) Kansas	0.13	0.17	0.04	10,000	0.04
(29) East Colorado	0.09	0.10	0.04	10,000	0.05
(30) Opal	0.09	0.10	0.04	10,000	0.05
(32) San Juan Basin	0.09	0.10	0.04	10,000	0.13
(34) North Wyoming	0.09	0.10	0.04	10,000	0.05
(36) SOCAL Area	0.01	0.91	0.04	10,000	0.13
(37) Enhanced Oil Recovery Region	0.02	0.81	0.04	10,000	0.13
(38) PGE Area	0.03	0.88	0.04	10,000	0.13
(41) Montana/ North Dakota	0.04	0.72	0.04	10,000	0.13
(45) Pacific Northwest	0.26	0.00	0.04	10,000	0.02
(49) Eastern Canada Offshore	0.01	0.88	0.04	2,500	0.06
(54) North Alabama	0.04	0.22	0.04	10,000	0.03
(55) Alabama Offshore	0.04	0.22	0.04	2,500	0.03
(57) East Louisiana Shelf	0.07	0.52	0.04	2,500	0.04
(58) Eastern Louisiana Hub	0.11	0.27	0.04	10,000	0.04
(59) Viosca Knoll S./ Desoto Canyon/Mississippi Canyon	0.07	0.52	0.04	2,500	0.04
(60) Henry Hub	0.11	0.27	0.04	10,000	0.04

Region	Fraction of Hydrocarbons that are Natural Gas Liquids (NGLs) (Fraction)	Fraction of Hydrocarbons that are Crude Oil (Fraction)	Max Share of Resources that can be Developed per Year (Fraction)	Exploration, Development Drilling Required (Ft/Bcf)	Lease and Plant Use (Fraction)
(61) North Louisiana Hub	0.08	0.08	0.04	10,000	0.04
(62) Central and West Louisiana Shelf	0.07	0.52	0.04	2,500	0.04
(63) Southwest Texas	0.12	0.52	0.04	10,000	0.05
(64) Dallas/Fort Worth	0.07	0.06	0.04	10,000	0.05
(65) E. TX (Katy)	0.17	0.19	0.04	10,000	0.05
(66) S. TX	0.12	0.07	0.04	10,000	0.05
(67) Offshore Texas	0.06	0.25	0.04	2,500	0.05
(68) NW TX	0.22	0.05	0.04	10,000	0.05
(69) Garden Banks	0.06	0.25	0.04	2,500	0.04
(70) Green Canyon	0.07	0.52	0.04	2,500	0.04
(71) Florida off-shore moratorium area	0.07	0.52	0.04	2,500	0.04
(72) North British Columbia	0.01	0.05	0.04	10,000	0.08
(74) Caroline	0.03	0.19	0.04	10,000	0.10
(76) Saskatchewan	0.00	0.73	0.04	10,000	0.07
(80) West Virginia	0.07	0.04	0.04	10,000	0.04
(83) Wind River Basin	0.09	0.10	0.04	10,000	0.05
(86) McKenzie Delta	0.00	0.00	0.04	10,000	0.08
(87) Southern Alaska	0.00	0.00	0.04	10,000	0.08
(89) Northern Alaska	0.00	0.00	0.04	10,000	0.08
(90) Arctic	0.05	0.55	0.04	10,000	0.08
(92) SW Virginia	0.00	0.01	0.04	10,000	0.02
(96) Florida	0.02	0.82	0.04	10,000	0.21
(98) Southwest Michigan	0.04	0.11	0.04	10,000	0.04
(99) Central Michigan	0.04	0.11	0.04	10,000	0.04
(107) Carthage	0.08	0.08	0.04	10,000	0.05
(108) Southwest Oklahoma	0.13	0.17	0.04	10,000	0.04
(109) Northeast Oklahoma	0.13	0.17	0.04	10,000	0.04
(110) Southeastern Oklahoma	0.13	0.17	0.04	10,000	0.04
(111) Northern Arkansas	0.00	0.13	0.04	10,000	0.04
(113) Uinta/Piceance	0.09	0.10	0.04	10,000	0.05
(114) South MS/AL	0.04	0.22	0.04	10,000	0.03

Other drilling constraints include rig capacity, rig retirement, rig growth, and drilling speed. Values for the constraints are specified for each of the three drilling category: (1) onshore, (2) offshore shelf, and (3) offshore deepwater. The drilling rig capacity constraint shows the number of drilling rigs initially available in the base year 2011. The initial rig counts are 3,798 rigs for onshore, 115 rigs for offshore shelf, and 115 rigs for offshore deepwater and the numbers can change over time controlled by rig retirement and rig growth constraints. The drilling rig retirement constraint is the share of rig capacity that can retire in a year. The drilling rig growth constraint is the maximum increase of total rig count in a year. The drilling retirement and growth are assumed to be the same for all drilling category and the constraints are set to 0.5% per year and 3.5% per year, respectively.

Another growth constraint, minimum drilling capacity increase, is implemented to force the rig count to grow by at least one rig in each drilling category. The drilling speed constraint is the required speed in feet/day/rig for successful exploration and development. The drilling speed required for successful E&D grows over time, as shown in Figure 10-11 and differs for onshore and offshore (which in this case includes both shelf and deep shelf).

Figure 10-11 Drilling Rig Speed Constraint



10.4.3 Reserves-to-Production (R/P) Ratio

The reserves-to-production ratio is the remaining amount of reserves, expressed in years, to be produced with a current annual production rate. In the IPM gas module, the R/P data obtained from the HSM is provided in the form of production-to-reserves (P/R) ratio (or reciprocal of the R/P ratio). The P/R ratio is used to calculate annual wet gas production from the reserves and the value varies by resource type and production node. For conventional gas the P/R ratio ranges from 0.04 (or 25 years of R/P) to 0.25 (or 4 years of R/P) with average of 0.13 (or 8 years of R/P). The P/R ratio of shale and tight gas is half of that of the conventional gas with average P/R ratio of 0.06 (or 16 years of R/P). Coalbed methane gas has the lowest P/R ratio with average of 0.03 (or 32 years of R/P) or half of that of the tight and shale gas.

10.4.4 Variable Costs, Natural Gas Liquid Share, and Crude Oil Share

In the IPM natural gas module, the variable costs include production operations and maintenance (O&M) cost and gas processing cost. The production O&M cost for 2011 is estimated to be $0.51/MMBtu (in real 2007 dollars) and is assumed to be the same for all supply regions. The production O&M cost is expected to decline over time due to improvements in production technology. In the model the same technology improvement factor shown in Figure 10-9 is applied to the production O&M cost.

The resource data from the HSM is provided in the form of total hydrocarbon (oil, gas, and NGL) resource. The HSM also provides the allocations of the hydrocarbon for dry gas, oil, and NGL.

Table 10-5 shows the shares of NGL (column 2) and crude oil (column 3) by supply region. Associated gas from crude oil and NGL from wet gas are processed in gas processing plants to produce pipeline quality dry gas. Node level gas processing cost for IPM natural gas module is obtained from the GMM. The processing cost varies from $0.07/MMBtu (of wet gas in real 2007 dollars) to $0.56/MMBtu with average of $0.22/MMBtu.

10.4.5 Lease and Plant Gas Use

The term "lease and plant gas" refers to the gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and as fuel in gas processing plants. The data for lease and plant gas use is derived for the HSM as a fraction of wet gas production and varies by region. The value ranges from 0.01 to as high as 0.3 with an average of around 0.06 (column 6 in Table 10-5).

10.5 Liquefied Natural Gas (LNG) Imports

As described earlier, most of the data related to North American LNG imports is derived from the GMM LNG model. Based on a comprehensive database of existing and potential liquefaction and regasification facilities and worldwide LNG import/export activities, the model uses a simulation procedure to create the base year 2011 North American LNG supply curves and projections of regasification capacity and costs.

Key elements of the LNG model are described below.

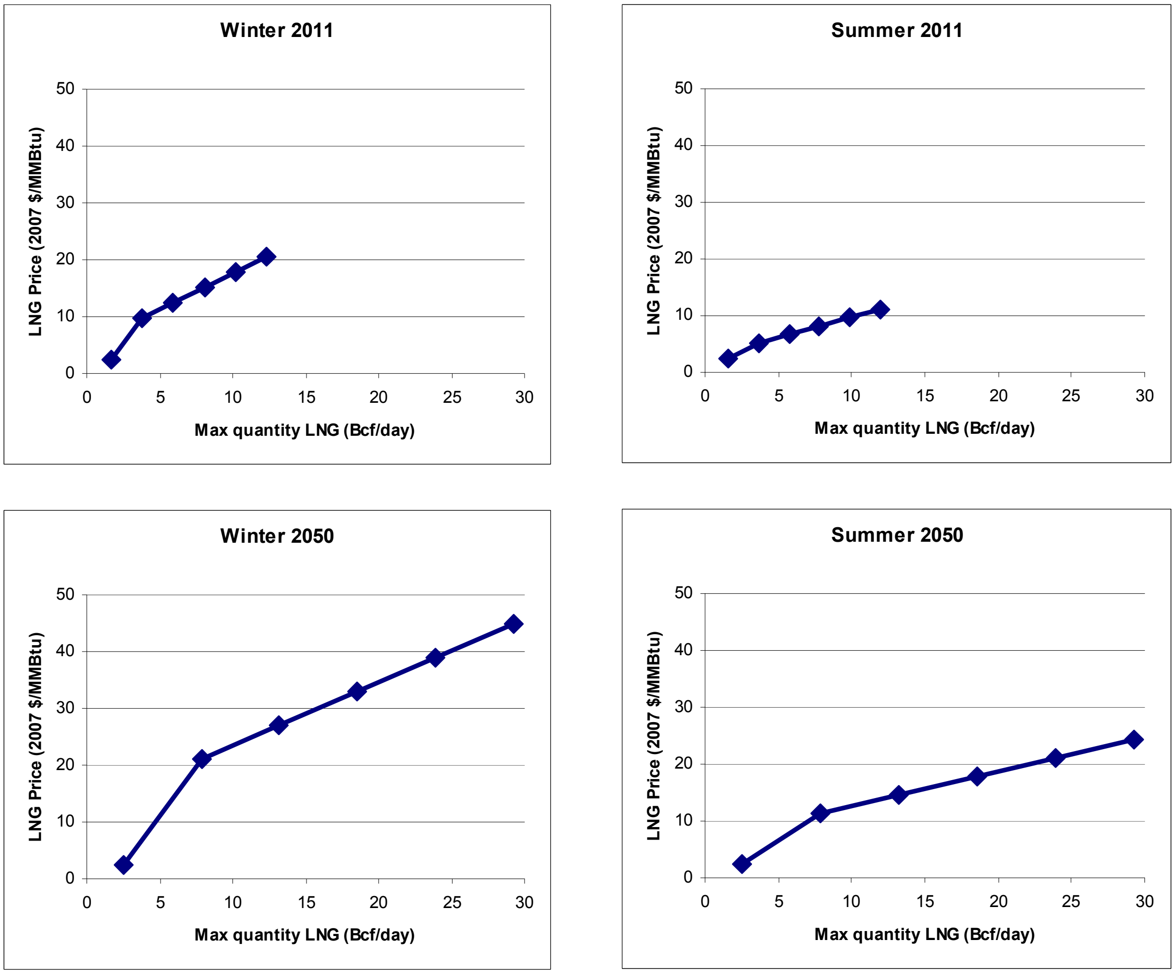
10.5.1 Liquefaction Facilities and LNG Supply

The supply side of the GMM LNG model takes into account capacities from existing as well as potential liquefaction facilities. The lower and upper boundaries of supply capacity allocated for each North American regasification facility are set by available firm contracts and swing supplies. Three point LNG supply curves are generated within this envelope where: (1) the lower point is the amount of firm LNG supply, (2) the upper bound is the firm imports plus the maximum swing imports available for that facility, and (3) the midpoint is the average of the minimum and maximum values. Prices for the minimum and maximum points are tied to Refiner Acquisition Cost of Crude (RACC) price.[22] The minimum price represents minimum production cost for liquefaction facilities and is set at 0.5 of RACC price and the maximum price is set at 1.5 of RACC price. The prices are then shifted up for winter months and shifted down in the summer months to represent the seasonal variation in competition from European LNG consumers.

The individual LNG supply curves from the GMM LNG model are aggregated to create total North American LNG supply curves describing LNG availability serving the North American regasification facilities. The three point curves are converted to six points by linear interpolation to provide more supply steps in the IPM natural gas module. Two LNG supply curves, one for winter and one for summer, are specified for each year starting from 2011 until 2054 to capture growth as well as seasonal variation of the LNG supplies. Figure 10-12 shows the North American LNG supply curves for the winters and summers of 2011 and 2050.

[22] Refiner Acquisition Cost of Crude Oil (RACC) is a term commonly use in discussing crude oil. It is the cost of crude oil to the refiner, including transportation and fees. The composite cost is the weighted average of domestic and imported crude oil costs.

Figure 10-12 North American LNG Supply Curves



10.5.2 Regasification Facilities

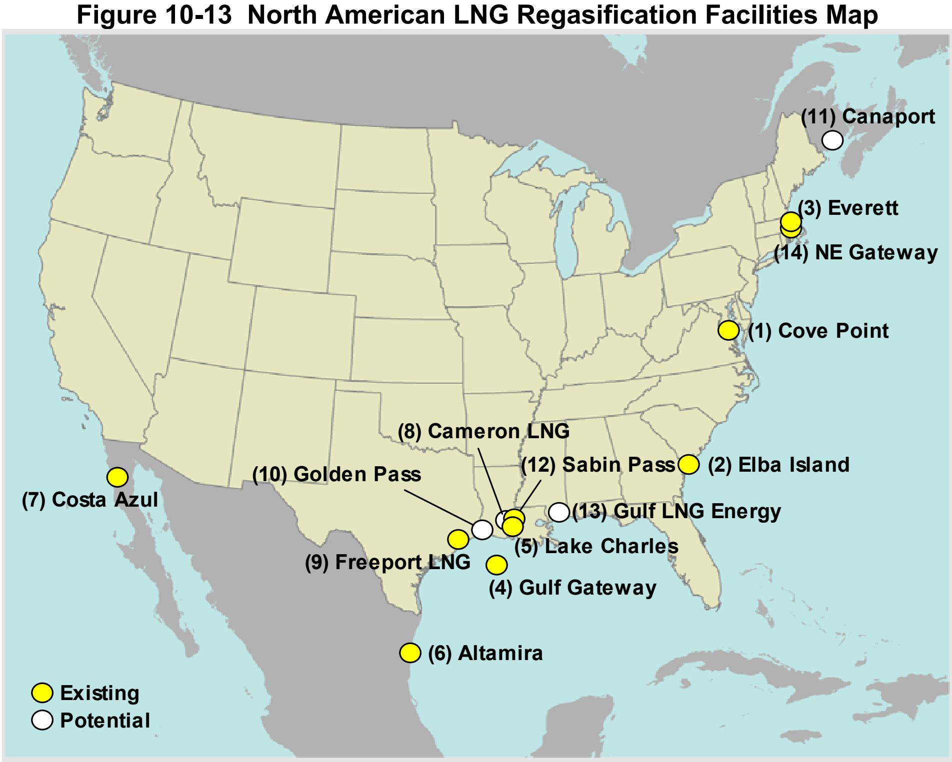
For the EPA Base Case, ten existing and four potentials North American LNG regasification facilities are considered in the IPM natural gas module. Table 10-6 lists the 14 facilities (current existing facilities are highlighted), the destination nodes where the LNG are delivered, and the base year 2011 capacity for each of the regasification facility. Figure 10-13 provides a map of these facilities. Existing Penuelas LNG facilities in Puerto Rico are not included because they are not part of the natural gas network in the IPM gas module. However, the electric generating units that consume gas from the Penuelas LNG facilities are included in the IPM electric module. In EPA Base Case v.4.10. the Penuelas LNG facilities are modeled with a fixed 150 MMcfd gas supply into Florida node and a link to connect the gas supply to the electric generating units in Puerto Rico.

Table 10-6 North American LNG Regasification Facilities

No	LNG Regasification Facility	Node Location	Base Year (2011) Regasification Capacity (Bcf/day)
1	Cove Point	(7) Cove Point TRANS	1.50
2	Elba Island	(9) Elba Is TRANS	2.10
3	Everett	(2) Everett TRANS	0.70

No	LNG Regasification Facility	Node Location	Base Year (2011) Regasification Capacity (Bcf/day)
4	Gulf Gateway	(69) Garden Banks	0.50
5	Lake Charles	(60) Henry Hub	2.10
6	Altamira	(51) Reynosa Imp/Exp	1.00
7	Costa Azul	(84) California Mexican Exports	2.00
8	Cameron LNG	(60) Henry Hub	1.50
9	Freeport LNG	(65) E. TX (Katy)	1.50
10	Golden Pass	(65) E. TX (Katy)	2.00
11	Canaport	(49) Eastern Canada Offshore	1.00
12	Sabine Pass	(60) Henry Hub	2.60
13	Gulf LNG Energy LLC	(56) North Mississippi	1.00
14	Northeast Gateway	(1) New England	0.80

Figure 10-13 North American LNG Regasification Facilities Map



10.5.3 LNG Regasification Capacity Expansions

The IPM natural gas module has two constraints for the regasification capacity expansion: (1) minimum LNG regasification facility capacity expansion and (2) maximum LNG regasification facility capacity expansion. The values are specified for each facility and year where the minimum constraint is used to force the model to add regasification capacity and the maximum constraint is the upper bound for the capacity expansion.

The decision of whether to expand regasification capacity is controlled by the two constraints and by a levelized capital cost for regasification capacity expansion. The base year 2011 levelized capital cost for capacity expansion (in real 2007 dollars per MMBtu of capacity expansion) is specified for each facility. A cost multiplier can be applied to represent the increase in levelized capital cost over time. The constraints for the capacity expansion can be used to turn on or off the regasification capacity expansion feature in the model. Setting both constraints to zero will deactivate this feature.

If the regasification capacity is allowed to expand, the model can add capacity to a facility within the minimum and maximum constraints if the cost of the regasification expansion contributes to the optimal solution, i.e., minimizes the overall costs to the power sector, including the capital cost for adding new regasification capacity less their revenues. The model takes into account all possible options/projects (including regasification capacity expansions) in any year that do not violate the constraints and selects the combination of options/projects that provide the minimum objective function value. In this way, regasification capacity expansion projects will compete with each other and even with other projects such as pipeline expansions, storage expansions, etc.

Due to excess LNG regasification capacity already in the system the regasification capacity expansion feature is not deployed in EPA Base Case v.4.10. EPA scenario results show very low total LNG utilizations, less than 15%, throughout the projection period which suggest the base year LNG regasification capacity is already high and requires no expansion.

10.6 End Use Demand

Non-power sector demand (i.e. the residential, commercial, and industrial) is modeled in the new gas module in the form of node-level firm and interruptible demand curves23. The firm demand curves are developed and used for residential, commercial, and some industrial sources, while the interruptible demand curves are developed and used exclusively for industrial sources.

A three step process is used to prepare these curves for use in the IPM gas module. First, GMM is used to develop sector specific econometric models representing the non-power sector demand. Since the GMM econometric models are functions of weather, economic growth, price elasticity, efficiency and technology improvements, and other factors, these drivers, in effect, are embedded in the resulting IPM natural gas module demand curves. Second, projections are made using the GMM econometric models and assembled into monthly gas demand curves by sector and demand node. Third, using a second model, seasonal and load segment specific demand curves are derived from the monthly gas demand curves. The sections below describe each of these steps in further detail.

10.6.1 Step 1: Developing Sector Specific Econometric Models of Non-Power Sector Demand

Residential/Commercial Sector

The GMM econometric models of residential and commercial demand are based on regression analysis of historical data for 41 demand regions and are adjusted to reflect conservation, efficiency, and technology changes over time. The regional data is allocated to the node level based on population data and information from the Energy Information Administration's "Annual Report of Natural and Supplemental Gas Supply & Disposition" (EIA Form-176). Specifically, the econometric models used monthly Department of Energy/Energy Information Administration (DOE/EIA) data from January 1984 through December 2002 for the U.S. and monthly Statistics Canada data from January 1988 through December 2000 for Canada.

23 "Firm" refers to natural gas demand that is not subject to interruptions from the supplier, whereas "interruptible" refers to natural gas demand that is subject to curtailment or cessation by the supplier.

The GMM econometric models showed node-level residential and commercial gas demand to be a function of heating degree days, elasticity of gas demand relative to GDP, and elasticity of gas demand relative to gas price. The GDP elasticity was generally about 0.4 for the residential sector and 0.6 for the commercial sector. The gas price elasticity was generally less than 0.1 for both sectors. Since gas demand in these sectors is relatively inelastic, GDP and price changes have small effects on demand.

U.S. Industrial Sector
The GMM econometric model of U.S. industrial gas demand employed historical data for 11 census-based regions and ten industry sectors, focusing on gas-intensive industries such as:

- Food
- Pulp and Paper
- Petroleum Refining
- Chemicals
- Stone, Clay and Glass
- Iron and Steel
- Primary Aluminum
- Other Primary Metals
- Other Manufacturing
- Non-Manufacturing

For each of these sectors three end-use categories (process heat, boilers, and other end uses) are modeled separately:

- Process heat: This includes all uses of gas for direct heating as opposed to indirect heating (e.g., steam production). The GMM econometric modeling indicated that forecasts for process heat for each industrial sector are a function of growth in output, the energy intensity trend, and the price elasticity. Growth in output over time for most industries is controlled by industrial production indices. Energy intensity is a measure of the amount of gas consumed per unit of output. Energy intensity tends to decrease over time as industries become more efficient.
- Boilers: This category includes natural gas-fired boilers whose purpose is to meet industrial steam demand. GMM econometric models indicated that gas demand for boilers is a function of the growth in industrial output and the amount of gas-to-oil switching. Industry steam requirements grow based on industrial production growth. A large percentage of the nominally “dual-fired” boilers cannot switch due to environmental and technical constraints.
- Other end uses: This category includes all other uses for gas, including non-boiler cogeneration, on-site electricity generation, and space heating. Like the forecasts for process heat, the GMM econometric modeling showed “other end uses” for each industrial sector to be a function of growth in output, the energy intensity trend, and the price elasticity.

In addition to these demand models, a separate regression model was use to characterize the chemicals sector’s demand for natural gas as a feedstock for ammonia, methanol, and non-refinery hydrogen. Growth in the chemicals industry is represented by a log-linear regression model that relates the growth to GDP and natural gas prices. As GDP growth increases, chemical industry production increases; and as gas prices increase, chemical industry production decreases.

The GMM econometric models for the U.S. industrial sector used DOE/EIA monthly data from January 1991 through December 2000.

Canada Industrial Sector
The industrial sector in Canada is modeled in less detail. Canada is divided into 6 regions based on provincial boundaries. The approach employs a regression fit of historic data similar to that

used in the residential/commercial sectors. Sub-sectors of Canadian industrial demand are not modeled separately. The Canadian industrial sector also includes power generation gas demand. The model used Statistics Canada monthly data from January 1991 through December 2000.

10.6.2 Step 2: Use projections based on the GMM econometric models to produce monthly gas demand curves by sector and demand node

The regression functions resulting from the econometric exercises described in Step 1 are used to create monthly sector- and nodal-specific gas demand curves. To do this the functions are first populated with the macroeconomic assumptions that are consistent with those used in EPA Base Case 4.10. For these purposes a U.S. annual GDP growth rate of 3.0%, a U.S. annual industrial production growth rate of 2.3%, and a Canadian annual GDP growth rate of 2.5 % are assumed. Then, a range of natural gas prices are fed into the regression functions. At each gas price the regression functions report out projected monthly demand by sector and node. These are the GMM's nodal demand curves.

10.6.3 Step 3: Develop non-electric sector natural gas demand curves that correspond to the seasons and segments in the load duration curves used in IPM

A second model, the Daily Gas Load Model (DGLM), is used to create daily gas load curves based on the GMM monthly gas demand curves obtained in Step 2. The DGLM uses the same gas demand algorithms as the GMM, but uses a daily temperature series to generate daily variations in demand, in contrast to the seasonal variations in gas demand that are obtained from the GMM.

The resulting daily nodal demand data for each non-power demand sector are then re-aggregated into the two gas demand categories used in the IPM gas module: all of the residential and commercial demand plus 10% of the industrial demand is allocated to the firm gas demand curves, and the remaining 90% of the industrial demand is allocated to the interruptible gas demand curves.

IPM, the power sector model, has to take into account natural gas demand faced by electric generating units that dispatch in different segments of the load duration curves, since demand for natural gas and its resulting price may be very different for units dispatching in the peak load segment than it is for units dispatching in the base, high shoulder, mid shoulder, or low shoulder load segments. In addition, since seasonal differences in demand can be significant, IPM requires separate load segment demand data for each season that is modeled. In EPA Base Case v.4.10, there are two seasons: Summer (May 1 – September 30) and winter (October 1 – April 30). Therefore, the firm and interruptible daily gas demand and associated prices are allocated to the summer and winter load segment based on the applicable season and prevailing load conditions to produce the final non-electric sector gas demand curves that are used in IPM.

In EPA Base Case v.4.10, each of the summer and winter periods uses 6 load segments for pre-2030 and 4 load segments for post-2030 as shown in Table 10-7. The "Peak" load segment in post-2030 is an aggregate of "Needle Peak" and "Near Peak" load segments in the pre-2030. The "High Shoulder" load segment in post-2030 is an aggregate of "High Shoulder" and "Middle Shoulder" load segments in the pre-2030. The same definitions of "Low Shoulder" and "Base" load segments are applied to both pre-2030 and post-2030. Input data for firm and interruptible demand curves are specified for all six load segments listed in the pre-2030 column of Table 10-7.

Table 10-7 Summer and Winter Load Segments in EPA Base Case v.4.10

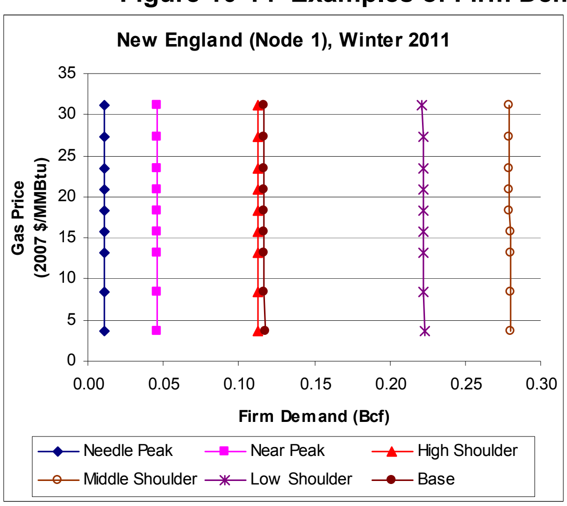
Pre 2030		Post 2030	
1	Needle Peak	1	Peak
2	Near Peak		
3	High Shoulder	2	High Shoulder
4	Middle Shoulder		
5	Low Shoulder	3	Low Shoulder
6	Base	4	Base

Aggregation of summer and winter load segments from six in the pre-2030 to four in the post-2030 is performed endogenously in the model.

The non-electric sector demand curves (firm and interruptible) are generated based on GMM regressions described above with macroeconomic assumptions consistent with those of EPA Base Case v.4.10. A set of firm and interruptible gas demand curves is generated for each node and year. Examples of node-specific firm and interruptible demand curves for summer and winter load segments are shown in Figure 10-14 and Figure 10-15. It should be noted that firm gas demand (Figure 10-14) is very inelastic; only a small fraction of demand is shed as prices increase. The interruptible gas demand in the peak segments is also very inelastic as expected with higher elasticities in the shoulder and base load segments.

It is important to note that the non-electric gas demand curves provided to the IPM/Gas model are static inputs. The implied elasticities in the curves represent short-term elasticities based on EPA Base Case v.4.10 macroeconomic assumptions. Long-term elasticity is not factored into the gas demand curves. In other words, changes in the assumptions that affect the price/volume solutions have no effect to the long-term gas demand elasticity. Sensitivity runs with slight modifications to the macroeconomic assumptions can still use the same curves if the gas demand forecast is expected not to be much different than that from the base case. In this case, changes in the gas demand solutions have minor effect to the long-term elasticity. However, a sensitivity run (e.g. carbon policy run) with major changes in CO_2 allowance prices should not use the same gas demand curves because it will have higher impact to the long-term gas demand elasticity. A new set of non-electric gas demand curves needs to be generated for this type of run.

Figure 10-14 Examples of Firm Demand Curves by Electric Load Segment



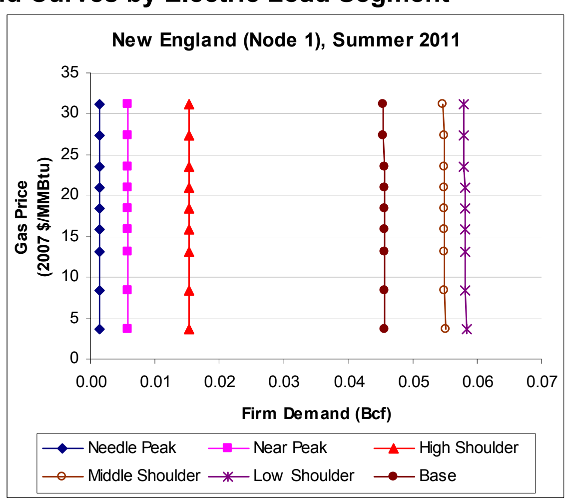
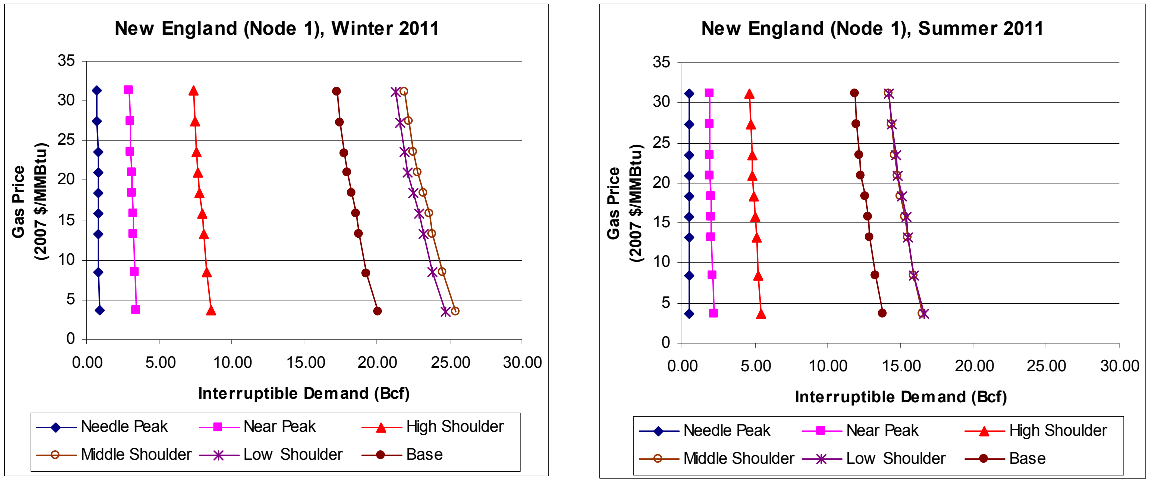


Figure 10-15 Examples of Interruptible Demand Curves by Electric Load Segment



10.7 Pipeline Network

10.7.1 Network Structure

The pipeline network in the IPM natural gas module represents major transmission corridors (not individual pipelines) throughout North America. It contains 343[1] gas pipeline corridors (including bi-directional links) between the 114 nodes (Figure 10-3). Each corridor is characterized by maximum capacity and a "value of service" (discount curve) relationship that determines the market value of capacity as a function of load factor.[2] The node structure is developed to reflect points of change or influence on the pipeline system such as:

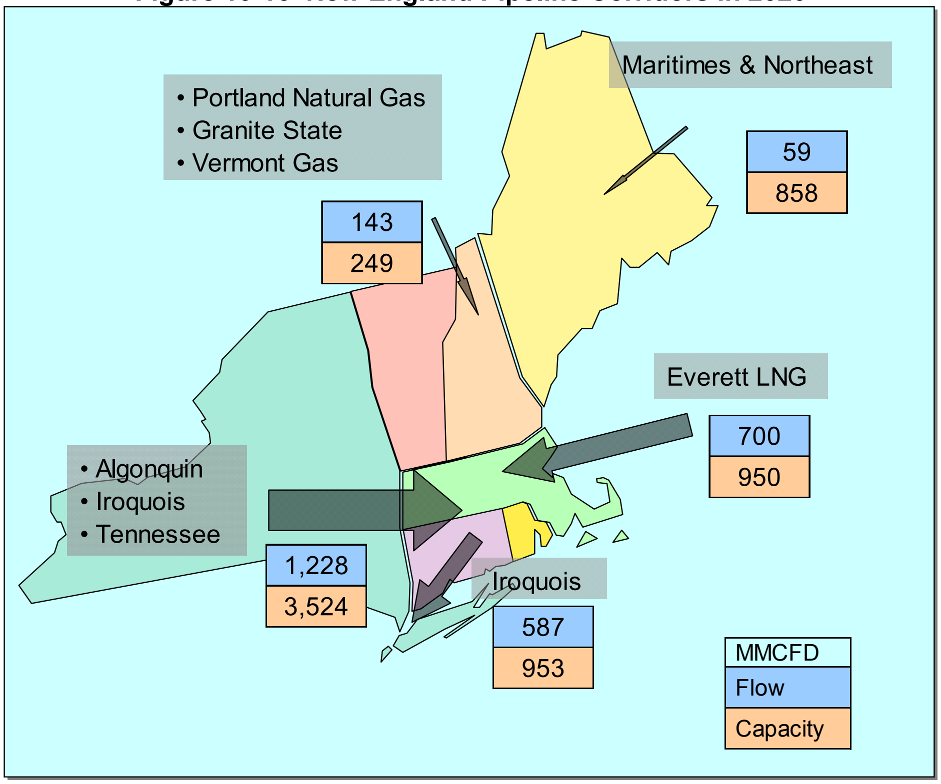
- Major demand and supply centers
- Pipeline Hubs and market centers
- Points of divergence in pipeline corridors

To illustrate the relationship of corridors and pipelines, Figure 10-16 shows the flow and capacity of five pipeline corridors in New England in 2020. Gas flows into New England along three pipeline corridors (indicated in Figure 10-16 by 3 of the 4 arrows that point into the region) representing a total of seven pipeline systems (indicated by name labels in Figure 10-16). New England also receives gas via the Everett LNG terminal (indicated in Figure 10-16 by the 4th arrow that points into the region). Also, some of the gas that flows into New England on the Iroquois system flows through the region and back to downstate New York; this is represented on the map as an export from New England (indicated in Figure 10-16 by the arrow that points away from the region).

[1] Excluding LNG import Terminal nodes and their pipeline connections.

[2] See footnote #3 above for a definition of "load factor."

Figure 10-16 New England Pipeline Corridors in 2020



10.7.2 Pipeline Transportation Costs

In the IPM natural gas module, the natural gas moves over the pipeline network at variable cost. The variable cost as a function pipeline throughput (or pipeline discount curve) is used to determine transportation basis[3] (i.e., the market value of capacity) for each period in the forecast for each pipeline link. The 4-point pipeline discount curves in the IPM natural gas module are simplified forms of the more robust continuous discount curves from the GMM pipeline module. The GMM pipeline discount curves have been derived in the course of extensive work to calibrate the model to actual history. The curves have been fit to basis differentials observed from actual gas prices and to annual load factors from pipeline electronic bulletin boards via Lippman Consulting, Inc.

The GMM continuous discount curves are converted to 4-point linear curves for the IPM natural gas module capturing deflection points in the GMM discount curves. Figure 10-17 depicts the base year 2011 discount curve for the pipeline corridor connecting nodes (61) North Louisiana Hub and (18) Tennessee/Kentucky. Cost growth factors shown in Figure 10-18 are applied to the pipeline discount curves to reflect cost increase over time. The cost is assumed to grow at an average rate of 0.5 percent per year.

[3] See footnote #1 above for a definition of “basis.”

Figure 10-17 Example Pipeline Discount Curve

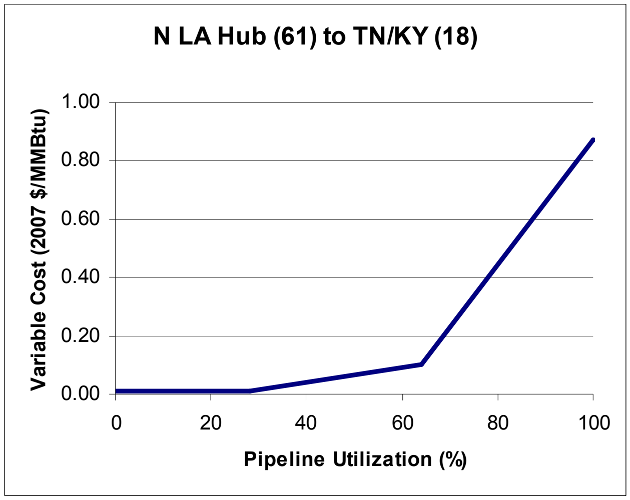
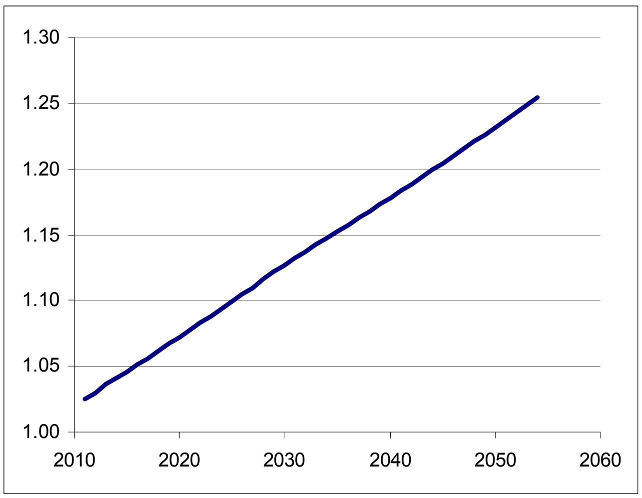


Figure 10-18 Pipeline Cost Growth Factor



10.7.3 Pipeline Capacity Expansion Logic

Base year pipeline capacity, derived from GMM, includes existing capacities and planned capacities that are expected to be operational from the beginning of 2011. The IPM natural gas module has the capability to endogenously expand the pipeline capacity. The decision of whether to expand pipeline capacity is controlled by two constraints, which stipulate minimum and maximum capacity additions and by the levelized capital cost of expanding pipeline capacity in the specific corridor and year. The minimum capacity addition constraint forces the model to add capacity in a specified corridor and year. The maximum capacity constraint is the upper bound on capacity additions in a specified corridor and year. For most pipeline corridors there is no minimum or maximum capacity requirement, and so they are assigned a value of zero as their minimum capacity addition requirement and infinity[4] as their maximum capacity addition requirement. Where this occurs, the pipeline expansion is only controlled by the pipeline capital cost.

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[4]In the model this is achieved by assigning a large number, e.g., 100 Bcfd, for every year where there is no constraint on maximum capacity.

The model is allowed to add capacity to a pipeline corridor within the minimum and maximum capacity addition constraints if the cost of the pipeline expansion contributes to the optimal solution, i.e., minimizes the overall costs to the power sector, including the capital cost for pipeline capacity expansion, less their revenues. The model takes into account all possible options/projects including capacity additions for pipeline corridors in any year that do not violate the constraints and selects the combination of options/projects that provide the minimum objective function. In this way, pipeline corridor expansion projects will compete with each other and even with other projects such as LNG regasification capacity expansions, storage expansions, etc.

For EPA Base Case v.4.10, pipeline corridors connecting North Alaska (node 89) and Mackenzie Delta (node 86) to North British Columbia (node 72) have the minimum and maximum capacity addition constraints. Based on diagnostic run analysis discussed in Section 3, the Mackenzie Delta pipeline project is not made available throughout the projection. Both capacity addition constraints for Mackenzie delta are set to zero. Based on the same analysis, the Alaska pipeline corridors (connecting nodes 89, 88, 87, and 72) are set to come online from 2035. The minimum capacity constraint is set to zero throughout the projection. The maximum capacity constraint is initially set to zero to restrict pipeline builds and then set to infinity from 2035.

Expansions in other pipeline corridors are not restricted. The model is allowed to build capacity to any pipeline corridors at any time as long as it contributes to minimization of the objective function. There is no reason for restricting the upper bound for capacity expansion since the IPM/Gas model was designed to be used as a long-term policy tool rather than a pipeline analysis tool. Having no restriction to the minimum capacity expansion, however, is a limitation of the model as it may lead to unrealistic capacity expansions especially for large pipeline projects such as Alaska and Mackenzie Delta. Without restricting the starting dates and the capacities, the model may build unrealistically low incremental capacities throughout the projection. This was the reason for conducting the diagnostic run for Alaska and Mackenzie Delta projects. Theoretically, it is possible to add capability in the model to make decisions on minimum incremental pipeline capacity expansions. However, it requires adding a lot more constraints to the LP which may result in prohibitively large model. The workaround for ensuring reasonable capacity expansion results is to perform diagnostic runs such as that for Alaska and Mackenzie Delta.

The base year 2011 levelized pipeline capital cost (in real 2007 dollars per MMBtu/Day of pipeline capacity addition) is specified for each of the 343 pipeline links. The cost growth factors shown in Figure 10-18 are applied to derive the cost increase over time. The average levelized capital cost for pipeline capacity expansion for 2011 is $154 per MMBtu/Day. The expected levelized capital cost for North Alaska pipeline for 2035 is $305 per MMBtu/Day.

10.8 Gas Storage

The IPM natural gas module has 108 underground storage facilities that are linked to 48 nodes. The underground storage is grouped into three categories based on storage "Days Service."[5]

- "20-Day" high deliverability storage – 35 storage facilities
- "80-Day" depleted/aquifer reservoirs – 38 storage facilities
- "Over 80 Days" depleted/aquifer reservoirs – 35 storage facilities

The model also includes existing and potential LNG peak shaving storage facilities. The existing facilities are linked to 24 nodes with allocations based on historical capacity data. There are 48 other nodes that are linked to LNG peakshaving storage. These facilities do not currently have capacity but are included in the storage database for the purpose of future expansion. The map of storage facility locations is shown in Figure 10-6 and the list of storage facility nodes is shown in Table 10-8.

[5] See footnote #5 above for a definition of "Days Service."

In Table 10-8 an X in columns 2 (“20-Day”), 3 (“80-Day”), or 4 (“Over 80-Days”) represents an underground storage facility. There are 108 such X’s which correspond to the 108 underground storage facilities noted in the previous paragraph. These 108 X’s appear in 48 rows, which represent the linked nodes noted in the previous paragraph. The identities of these nodes are found in column 1 (“Node”). Similarly, 24 X’s in columns 5 (“Existing”) represent the 24 existing LNG peakshaving facilities and 48 X’s in column 6 (“Potential”) represent the 48 prospective LNG storage facilities.

Table 10-8 List of Storage Nodes

Node	Underground Storage Facility			LNG Peakshaving Facility	
	20-Day	80-Day	Over 80 Days	Existing	Potential
(1) New England				X	
(3) Quebec	X		X		X
(4) New York City				X	
(5) Niagara	X	X	X		X
(6) Leidy	X	X	X		X
(8) Georgia				X	
(10) South Florida					X
(11) East Ohio	X	X	X		X
(12) Maumee/Defiance					X
(13) Lebanon					X
(14) Indiana		X	X	X	
(15) South Illinois	X	X	X		X
(16) North Illinois	X	X	X	X	
(17) Southeast Michigan	X	X			X
(18) Tennessee/Kentucky	X	X	X	X	
(19) MD/DC/Northern VA				X	
(20) Wisconsin				X	
(21) Northern Missouri					X
(22) Minnesota		X		X	
(23) Crystal Falls					X
(24) Ventura		X	X	X	
(26) Nebraska			X	X	
(28) Kansas	X	X	X		X
(29) East Colorado	X	X	X		X
(30) Opal	X	X			X
(31) Cheyenne	X	X	X		
(32) San Juan Basin			X		
(33) EPNG/TW					X
(34) North Wyoming			X		
(35) South Nevada					X
(36) SOCAL Area	X	X			X
(38) PGE Area	X	X			X
(41) Montana/North Dakota		X	X		X
(45) Pacific Northwest	X	X		X	

Node	Underground Storage Facility			LNG Peakshaving Facility	
	20-Day	80-Day	Over 80 Days	Existing	Potential
(46) NPC/PGT Hub				X	
(47) North Nevada				X	
(48) Idaho				X	
(54) North Alabama	X	X	X	X	
(56) North Mississippi	X	X			X
(58) Eastern Louisiana Hub	X		X		X
(60) Henry Hub	X	X	X		X
(61) North Louisiana Hub		X	X		X
(63) Southwest Texas	X	X	X		
(64) Dallas/Ft Worth	X	X	X		X
(65) E. TX (Katy)	X	X	X		X
(66) S. TX					X
(68) NW TX					X
(72) North British Columbia					X
(73) South British Columbia			X		X
(74) Caroline	X	X	X		X
(76) Saskatchewan	X	X	X		X
(77) Manitoba					X
(78) Dawn	X	X	X		X
(79) Philadelphia				X	
(80) West Virginia	X	X	X		X
(81) Eastern Canada Demand					X
(83) Wind River Basin			X		
(92) Southwest VA	X		X	X	
(93) Southeast VA				X	
(94) North Carolina				X	
(95) South Carolina				X	
(96) North Florida					X
(97) Arizona	X	X			X
(98) Southwest Michigan	X	X	X		X
(99) Northern Michigan	X	X	X		X
(103) SDG&E Demand				X	
(104) Eastern New York					X
(105) New Jersey				X	
(106) Toronto					X
(107) Carthage	X	X			X
(108) Southwest Oklahoma			X		X
(109) Northeast Oklahoma		X	X		X
(110) Southeastern Oklahoma	X	X			X
(111) Northern Arkansas	X	X		X	
(112) Southeast Missouri	X				X
(113) Uinta/Piceance		X	X		X

Node	Underground Storage Facility			LNG Peakshaving Facility	
	20-Day	80-Day	Over 80 Days	Existing	Potential
(114) South MS/AL	X	X			X

10.8.1 Storage Capacity and Injection/Withdrawal Constraints

Working gas capacity is initially allocated in the GMM to individual nodes based on historical data. Since the base year in EPA Base Case using IPM v.4.10 gas module is 2011, a projection of natural gas storage capacity at the end of 2010 is needed as a starting point. The expected working gas capacity as of EOY 2010 by location and storage type is obtained from the GMM as are injection and withdrawals rates. These serve as inputs to the IPM gas module, which uses them to endogenously derive gas storage withdrawals, injections, storage expansions, and associated costs. To give a sense of the EOY 2010 GMM storage input assumption in the IPM gas module, Table 10-9 shows the total working gas capacity and the average daily injection and withdrawal rates as percentage of working gas capacity for the four types of storage. Note that these are aggregated values (i.e., totals and averages); the actual GMM EOY 2010 inputs to the IPM gas module vary by location and storage type.

Table 10-9 Storage Capacity and Injection/Withdrawal Rates (EOY 2010)

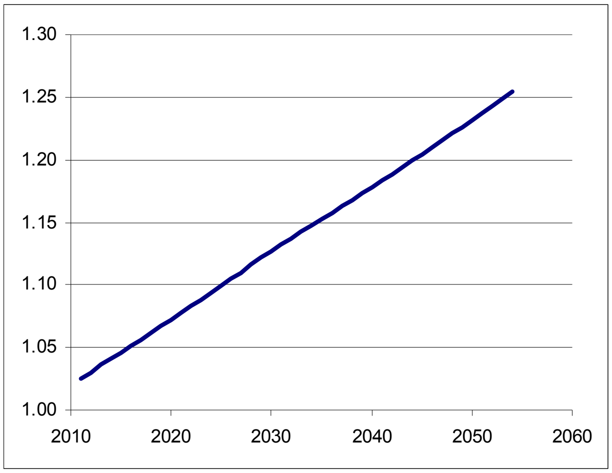
	Working Gas Capacity (Bcf)	Average Daily Injection Rate (Percent of WG Capacity)	Average Daily Withdrawal Rate (Percent of WG Capacity)
Underground Storage			
20 Day	458	6.7	9.3
80 Day	3,353	1.3	2.2
Over 80 Days	944	0.5	0.9
Total	4,755		
LNG Peakshaving Storage	84	0.5	12.5

10.8.2 Variable Cost and Fuel Use

In the IPM natural gas module, the natural gas is injected to storage or withdrawn from storage at variable cost. The base year 2011 variable cost or commodity[6] charge for underground storage facilities is assumed to be 1.54 cents/MMBtu and is the same for all underground storage nodes and types. The variable cost for LNG peakshaving facility is much higher at 36 cents/MMBtu as it includes variable costs for gas liquefaction (in gas injection process) and LNG regasification (in gas withdrawal process). The variable cost is assumed to be the same for all LNG peakshaving nodes. A storage cost growth factor shown in Figure 10-19 is applied to the injection/withdrawal cost to reflect cost increase over time. The cost is assumed to grow at an average rate of 0.5 percent per year.

[6] Storage commodity (variable) charge is generally a charge per unit of gas injected and/or withdrawn from storage as per the rights and obligations pertaining to a gas storage lease. Analogous to commodity charges for gas pipeline service

Figure 10-19 Storage Cost Growth Factor

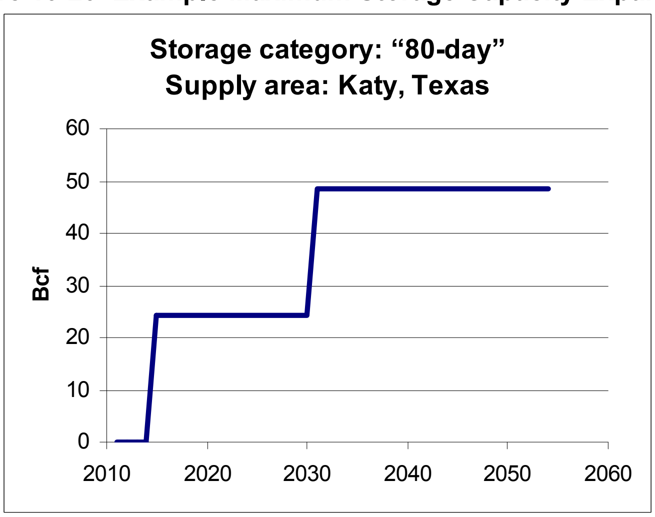


Fuel use for injection and withdrawal for underground storage is 1% of the gas throughput. The withdrawal fuel use for the LNG peakshaving storage is also 1% but the injection fuel use is much higher at 11% of the injection gas as it includes fuel use for gas liquefaction.

10.8.3 Storage Capacity Expansion Logic

The endogenous modeling decision of whether to expand working gas storage capacity is controlled by two constraints, which stipulate minimum and maximum capacity additions for each storage facility and year, and by the levelized capital cost of the storage expansion. The two constraints are specified as input data for each storage facility and year. The minimum constraint forces the model to add working gas capacity to the specified facility and year and the maximum constraint is the cap for the expansion. Figure 10-20 shows projected maximum storage expansion constraints for the “80-day” category storage facility in supply area Katy, Texas.

Figure 10-20 Example Maximum Storage Capacity Expansion



The model is allowed to add working gas capacity to a storage facility within the two constraints if the cost of storage expansion contributes to the optimal solution, i.e., minimizes the overall costs to the power sector, including the capital cost for working gas capacity expansion less their revenues. The model takes into account all possible options/projects including working gas capacity additions for storage facilities in any year that do not violate the constraints and selects the combination of options/projects that provide the minimum objective function value. In this way, storage capacity expansion projects will compete with each other and even with other projects such as LNG regasification capacity expansions, pipeline expansions, etc.

The base year 2011 levelized storage capital cost (in real 2007 dollars per MMBtu of storage capacity addition) is specified for each of the 180 storage facilities. Table 10-10 lists the average base year 2011 levelized storage capital cost for the four types of storage facility. Amongst the underground storage facilities the higher capital costs represent more storage cycles[7] that could be achieved in a year. On average, the capital costs for the "80-Day" and "20-Day" storage facilities are assumed to be 20 percent and 50 percent, respectively, higher than that of the "Over 80 Days" storage facility. The levelized capital cost for LNG peakshaving storage is much higher due to higher capital cost for the liquefaction unit. The cost growth factors shown in Figure 10-19 are applied to the capital cost to derive the cost increase over time. The capital cost is assumed to grow at an average rate of 0.5 percent per year.

Table 10-10 Base Year 2011 Average Levelized Storage Capital Cost

Storage Type	Average Levelized Storage Capital Cost (2007$/MMBtu)
Underground Storage	
20-Day	1.09
80-Day	0.86
Over 80 Days	0.72
LNG Peakshaving Storage	5.13

10.9 Fuel Prices

10.9.1 Crude Oil and Natural Gas Liquids Prices

Since a fraction of the hydrocarbons produced in the natural gas exploration and development process are crude oil and NGLs (see columns 2 and 3 in Table 10-5), revenues from crude oil and NGL production play a key role in determining the extent of exploration and development for natural gas. To take into account these revenues, crude oil and NGL price projections are provided as inputs to the IPM natural gas module and factored into the calculation of costs in the IPM objective function.

The crude oil and NGL price projections used in the IPM natural gas module are shown in Figure 10-21. These price projections were adapted from AEO 2009. No attempt was made to project prices beyond 2030 other than to assume that prices remain at their 2030 levels. The projected prices shown in Figure 10-21 are expressed in units of 2007$ per MMBtu. Using a crude oil Btu content of 5.8 MMBtu/Bbl, the projected crude oil prices in Figure 10-21 can be translated into the more familiar units of dollars per barrel (Bbl), in which case, prices in this figure are equivalent to $62/Bbl in 2011, $97/Bbl in 2015, $114/Bbl in 2020, and constant at $124/Bbl from 2030 (in real 2007 dollars) onward.

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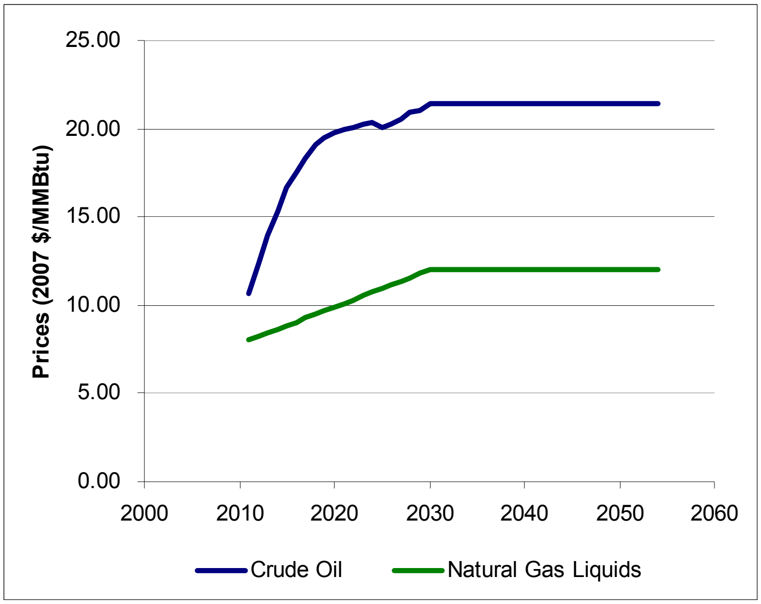
[7] One storage cycle is the theoretical time required to completely inject and withdraw the working gas quantity for any given underground gas storage facility or the turnover time for the working gas capacity rating of the facility. The cycle rate of any storage facility is usually expressed in cycles per year and is the number of times the working gas volumes can theoretically be turned over each storage year. The cycle rating for Porous Storage varies from 1 to 6 per year while that for Salt Cavern Storage are as high as 12 per year.

Figure 10-21 Crude Oil and NGL Prices



10.9.2 Natural Gas Prices

Node-level natural gas prices are outputs of the model and are obtained from the optimal solution of the combined IPM electric power sector and natural gas linear programming (LP) model. From a technical modeling standpoint, the node gas prices are what are called "shadow prices" or "dual variable values" associated with the node mass balance constraints at the optimal LP solution.

10.10 Outputs and Proxy Natural Gas Supply Curves

10.10.1 Outputs from the New IPM Natural Gas Module

Previous EPA IPM base cases reported natural gas consumption (in TBtu), Henry Hub and delivered natural gas prices (in $/MMBtu). In addition to these reports, the new natural gas module in EPA Base Case v.4.10 is capable of reporting natural gas supply (in Tcf), disposition (in Tcf), prices (in $/MMBtu), production (in Tcf) by supply region, end-of-year reserves and annual reserve additions (in Tcf), imports and exports (in Tcf), consumption by end-use sector and census division (in Tcf), prices by census division (in $/MMBtu), and inter-regional pipeline flows and LNG imports (in Bcf).

10.10.2 Proxy Natural Gas Supply Curves

In previous EPA IPM base cases a set of gas supply curves was generated outside of IPM (most recently by ICF's NANGAS (North American Natural Gas Analysis System) model) and then used in IPM as part of the base case input assumptions. (For a description of this approach see Appendix 8-2.9 "Technical Background Paper on the Development of Natural Gas Supply Curves for EPA Base Case 2004, v.2.1.9" in *Standalone Documentation for EPA Base Case 2004 (V.2.1.9) Using the Integrated Planning Model* EPA 430-R-05-011, September 2005. It is available for viewing and downloading at www.epa.gov/airmarkets/progsregs/epa-ipm/docs/bc8appendix.pdf.) The incorporation of the new fully integrated natural gas module into IPM eliminates the use of explicit gas supply curves, replacing them with more dynamic and responsive representation of an integrated natural gas supply chain and the U.S. power sector. However, it is recognized that it would be useful to have a set of proxy natural gas supply curves from the new integrated approach that could be compared to the natural gas supply curves used in previous EPA Base Cases. The proxy curves would only represent a one-time snapshot of supply/price relations resulting from the new integrated approach, but at least it would provide a point of comparison with the natural gas supply curves used in previous EPA IPM base cases.

Table 10-11 contains the proxy supply curves for the electric power sector for 2015 and 2020. (These are years that would be directly comparable with supply curves from previous base cases.) The curves were generated based on GMM supply elasticities and gas demand and price solutions from the IPM/Gas model. The supply elasticity is calculated from GMM for each of the IPM run years. The gas supply curve, for each IPM run year, is constructed by applying the supply elasticity around the price/quantity solution of gas consumption in the power sector from the IPM/Gas model (highlighted rows in

Table 10-11) varying the price from $3/MMBtu to $15/MMBtu (in real 2007 dollar). The supply elasticity, in the same run year, is assumed to be constant within the price range.

The proxy supply curves below specify annual price and volume relationships at the Henry Hub. For each listed step the price applies for all increments of supply greater than the value shown in the preceding step up to and including the supply level indicated in the current step.

Table 10-11 Proxy Natural Gas Supply Curves for EPA Base Case v.4.10

2015		2020	
Gas Price (2007$/MMBtu)	Gas Supply to Electric Sector (TBtu)	Gas Price (2007$/MMBtu)	Gas Supply to Electric Sector (TBtu)
3.00	4,385	3.00	5,688
3.11	4,469	3.08	5,762
3.23	4,552	3.16	5,836
3.34	4,633	3.23	5,909
3.45	4,713	3.31	5,981
3.56	4,792	3.39	6,052
3.68	4,870	3.47	6,123
3.79	4,946	3.55	6,192
3.90	5,022	3.63	6,261
4.02	5,096	3.70	6,329
4.13	5,169	3.78	6,397
4.24	5,242	3.86	6,464
4.36	5,313	3.94	6,530
4.47	5,384	4.02	6,595
4.58	5,453	4.09	6,660
4.69	5,522	4.17	6,724
4.81	5,590	4.25	6,788
5.08	5,741	4.53	7,000
5.34	5,887	4.82	7,205
5.61	6,030	5.10	7,405
5.88	6,171	5.38	7,601
6.15	6,308	5.66	7,791
6.42	6,442	5.95	7,977
6.69	6,574	6.23	8,159
6.95	6,703	6.51	8,337
7.22	6,831	6.80	8,511
7.49	6,956	7.08	8,682
7.76	7,078	7.36	8,850
8.03	7,199	7.64	9,014
8.29	7,318	7.93	9,176

2015	
Gas Price (2007$/MMBtu)	**Gas Supply to Electric Sector (TBtu)**
8.56	7,435
8.83	7,551
9.10	7,665
9.37	7,777
9.64	7,888
9.90	7,997
10.17	8,105
10.44	8,212
10.71	8,317
10.98	8,421
11.25	8,524
11.51	8,626
11.78	8,726
12.05	8,826
12.32	8,924
12.59	9,022
12.85	9,118
13.12	9,214
13.39	9,308
13.66	9,402
13.93	9,495
14.20	9,587
14.46	9,678
14.73	9,768
15.00	9,859

2020	
Gas Price (2007$/MMBtu)	**Gas Supply to Electric Sector (TBtu)**
8.21	9,335
8.49	9,492
8.78	9,646
9.06	9,798
9.34	9,947
9.63	10,094
9.91	10,240
10.19	10,383
10.47	10,524
10.76	10,664
11.04	10,802
11.32	10,938
11.61	11,073
11.89	11,206
12.17	11,337
12.45	11,467
12.74	11,596
13.02	11,723
13.30	11,849
13.59	11,973
13.87	12,097
14.15	12,219
14.43	12,340
14.72	12,460
15.00	12,581

Glossary of Terms Used in this Section
For ease of reference Table 10-12 assembles in one table terms that have been defined in footnotes throughout this chapter.

Table 10-12 Glossary of Natural Gas Terms Used in Documentation

Term	Definition
Arps-Roberts equation	“Arps-Roberts equation” refers to the statistical model of petroleum discovery developed by J. J. Arps, and T. G. Roberts, T. G., in the 1950’s.
Associated gas	Associated gas refers to natural gas that is produced in association with crude oil production, whereas non-associated gas is natural gas that is not in contact with significant quantities of crude oil in the reservoir.
Basis	In natural gas discussions “basis” refers to differences in the price of natural gas in two different geographical locations. In the marketplace “basis” typically means the difference between the NYMEX futures price at the Henry Hub and the cash price at other market points. In the modeling context “basis” means the difference in natural gas prices between any two nodes at the same instance in time.

Term	Definition
Decline curve	A decline curve is a plot of the rate of gas production against time. Since the production rate decline is associated with pressure decreases from oil and gas production, the curve tends to smoothly decline from a high early production rate to lower later production rate. Exponential, harmonic, and hyperbolic equations are typically used to represent the decline curve.
Depleted reservoir storage	A gas or oil reservoir that is converted for gas storage operations. Its economically recoverable reserves have usually been nearly or completely produced prior to the conversion.
Dry gas	Natural gas is a combustible mixture of hydrocarbon gases. Although consisting primarily of methane, the composition of natural gas can vary widely to include propane, butane, ethane, and pentane. Natural gas is referred to as 'dry' when it is almost pure methane, having had most of the other commonly associated hydrocarbons removed. When other hydrocarbons are present, the natural gas is called 'wet'.
Ethane rejection	Ethane rejection occurs when the ethane component in the natural gas stream is not recovered in a gas processing plant but left in the marketable natural gas stream. Ethane rejection is deployed when the value of ethane is worth more in the gas stream than as an a separate commodity or as a component of natural gas liquids (NGL), which collectively refers to ethane, propane, normal butane, isobutane, and pentanes in processed and purified finished form. Information that characterizes ethane rejection by region can play a role in determining the production level and cost of natural gas by region.
Firm and interruptible demand	“Firm” refers to natural gas demand that is not subject to interruptions from the supplier, whereas “interruptible” refers to natural gas demand that is subject to curtailment or cessation by the supplier.
High deliverability storage	High deliverability storage is depleted reservoir storage facility or Salt Cavern storage whose design allows a relatively quick turnover of the working gas capacity.
Lease and plant use	Natural gas for “lease and plant use” refers to the gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and as fuel in gas processing plants.
Liquefied Natural Gas (LNG)	LNG is natural gas converted to liquid form by cooling it down to about -260° F. Known as liquefaction, the cooling process is performed in an “LNG train” (the liquefaction and purification facilities in LNG plants), which reduces the gas to 1/600th of its original volume. The volume reduction resulting from liquefaction makes it cost effective to transport the LNG over long distances, typically by specially designed, double-hulled ships known as LNG carriers. Once the carriers reach their import terminal destination, the LNG is transferred in liquid form to specially designed storage tanks. When needed for customers, the LNG is warmed back to a gaseous state in a regasification facility and transported to its final destination by pipelines.
LNG peakshaving facility	LNG peakshaving facilities supplement deliveries of natural gas during times of peak periods. LNG peak shaving facilities have a regasification unit attached, but may or may not have a liquefaction unit. Facilities without a liquefaction unit depend upon tank trucks to bring LNG from nearby sources.

Term	Definition
Load factor	In the natural gas context “load factor” refers to the percentage of the pipeline capacity that is utilized at a given time.
Natural gas liquid (NGL)	Those hydrocarbons in natural gas that are separated from the gas as liquids in gas processing or cycling plants. Generally such liquids consist of propane and heavier hydrocarbons and are commonly referred to as lease condensate, natural gasoline, and liquefied petroleum gases.
Play	A “play” refers to a set of known or postulated natural gas (or oil) accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type.
Pool	A “pool” is a subsurface accumulation of oil and other hydrocarbons. Pools are not necessarily big caverns. They can be small oil-filled pores. A “field” is an accumulation of hydrocarbons in the subsurface of sufficient size to be of economic interest. A field can consist of one or more pools.
Proven (or proved)	The term “proven” refers to the estimation of the quantities of natural gas resources 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. Among the factors considered are drilling results, production, and historical trends. Proven reserves are the most certain portion of the resource base.
RACC price	Refiner Acquisition Cost of Crude Oil (RACC) is a term commonly use in discussing crude oil. It is the cost of crude oil to the refiner, including transportation and fees. The composite cost is the weighted average of domestic and imported crude oil costs.
Raw gas	Raw gas production refers to the volumes of natural gas extracted from underground sources, whereas net gas production refers to the volume of purified, marketable natural gas leaving the natural gas processing plant.
Reserves-to-production (R/P) ratio	Reserves-to-production ratio is the remaining amount of reserves, expressed in years, to be produced with a current annual production rate.
Resource and reserves	When referring to natural gas a distinction is made between “resources” and “reserves.” “Resources” are concentrations of natural gas that are or may become of potential economic interest. “Reserves” are that part of the natural gas resource that has been fully evaluated and determined to be commercially viable to produce.
Resource appreciation	Resource appreciation represents growth in ultimate resource estimates attributed to success in extracting resource from known plays such as natural gas from shales, coal seams, offshore deepwater, and gas hydrates that are not included in the resource base estimates.
Storage "Days Service"	Storage “Days Service” refers to the number of days required to completely withdraw the maximum working gas inventory associated with an underground storage facility.
Storage commodity charge	Storage commodity (variable) charge is generally a charge per unit of gas injected and/or withdrawn from storage as per the rights and obligations pertaining to a gas storage lease. Analogous to commodity charges for gas pipeline service

Term	Definition
Storage cycle	One storage cycle is the theoretical time required to completely inject and withdraw the working gas quantity for any given underground gas storage facility or the turnover time for the working gas capacity rating of the facility. The cycle rate of any storage facility is usually expressed in cycles per year and is the number of times the working gas volumes can theoretically be turned over each storage year. The cycle rating for Porous Storage varies from 1 to 6 per year while that for Salt Cavern Storage are as high as 12 per year.
Unconventional gas	Unconventional gas refers to natural gas found in geological environments that differ from conventional hydrocarbon traps. It includes: (a) "tight gas," i.e., natural gas found in relatively impermeable (very low porosity and permeability) sandstone and carbonate rocks; (b) "shale gas," i.e., natural gas in the joints, fractures or the matrix of shales, the most prevalent low permeability low porosity sedimentary rock on earth; and (c) "coal bed methane," which refers to methane (the key component of natural gas) found in coal seams, where it was generated during coal formation and contained in the microstructure of coal. Unconventional natural gas is distinguished from conventional gas which is extracted using traditional methods, typically from a well drilled into a geological formation exploiting natural subsurface pressure or artificial lifting to bring the gas and associated hydrocarbons to the wellhead at the surface.
Underground storage	The underground storage of natural gas in a porous and permeable rock formation topped by an impermeable cap rock, the pore space of which was originally filled with water.
Wet gas	A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in porous rock formations at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentane. Typical nonhydrocarbon gases that may be present in reservoir natural gas are water vapor, carbon dioxide, hydrogen sulfide, nitrogen and trace amounts of helium.
Working gas	The term "working gas" refers to natural gas that has been injected into an underground storage facility and stored therein temporarily with the intention of withdrawing it. It is distinguished from "base (or cushion) gas" which refers to the volume of gas that remains permanently in the storage reservoir in order to maintain adequate pressure and deliverability rates throughout the withdrawal season.

Appendix 10-1 EPA Base Case v.4.10 with AEO Gas Resource Assumptions

For purposes of comparison a variant of EPA Base Case v.4.10 was prepared with natural gas resource assumptions that were set to approximate those in the Energy Information Administration's Annual Energy Outlook 2010.

To set up this case, EPA asked ICF International, who had developed the natural gas module for EPA Base Case v.4.10, to determine how best to represent the AEO 2010 resource assumptions in IPM in view of structural differences between the two models. It should be noted that the only change between the original EPA base case and this variant are the natural gas resource assumptions. The base year proved reserves assumptions were not changed.[1] The following is a summary of the findings of ICF's comparison and the approach that was implemented in setting up the AEO 2010 gas resource base case variant.

ICF's analysis of the AEO 2010 natural gas resource assumptions was based on the AEO 2010 assumptions document.[2] ICF found that the gas resource base in AEO 2010 is defined as technically recoverable resources (as of beginning of year 2008) without reference to economic profitability, whereas the gas resource base in IPM is defined as the economically recoverable resource (as of end of year 2010) which represents that portion of the original-gas-in-place that is economic to develop at wellhead prices[3] below $14/MMBtu (in 2007 dollars) given current technologies and industry costs.

ICF made adjustments to convert the AEO technically recoverable gas resources so that it could be used in the IPM Natural Gas Module. Their analysis found that the economically recoverable gas resource as defined in the IPM natural gas module was about 15% to 30% lower than the technically recoverable gas resource without economic consideration as used in AEO 2010. However, since the resource base for conventional, tight gas, and coalbed methane gas in the EPA base case was already 15% to 30% lower than the gas resources in the AEO 2010, ICF did not change the gas resource base for these resource types.

On the other hand, ICF found that the shale gas resource in the EPA base case was much higher than in AEO 2010. To quantify the difference in shale gas resource, ICF first calculated that a 20% reduction was needed in order both to translate the AEO technically recoverable shale gas resource into the equivalent economically recoverable resource used in IPM and to account for resource development between 2008 (base year for the AEO gas resources) and 2011 (base year for the IPM gas resource). Once the two resource bases were expressed so they could be compared, ICF found that the AEO shale gas resource assumption was about 31% of that used in the EPA base case.

To implement this in the alternative base case, the total shale gas resource was set so it would be 31% of the shale gas resource base assumed in EPA Base Case v.4.10. No attempt was made

[1] The base year proved reserves assumptions are described in section 10.3 of this chapter under the header "Use of the HSM resource and reserves data in EPA Base Case using IPM v.4.10 Natural Gas Module."

[2] Energy Information Administration, *Assumptions to the Annual Energy Outlook 2010: Natural Gas Transmission and Distribution Module*, DOE/EIA-0554(2010), April 9, 2010. www.eia.doe.gov/oiaf/aeo/assumption/nat_gas.html

[3] The wellhead price is the price required to cover total wellhead resource costs including capital expenditures, cost of capital, operating costs, royalties, severance taxes and income taxes. Wellhead economics are based upon standard discounted cash flow analysis. Costs include drilling and completion, operating, geological and geophysical (G&G), and lease costs. Completion costs include hydraulic fracturing, and such costs are based upon cost per fracture stage and number of fracture stages. Drilling costs, well lateral length, number of fracture stages, and cost per fracture stage are based on analysis and data from industry.

to adjust shale gas resources by supply region so that the regional shale gas resources in AEO 2010 and EPA's AEO Supply Case would match.

Table 10-1.1 shows the resulting shale gas resource base assumptions for AEO 2010, EPA Base Case v.4.10, and the AEO Supply Case of the EPA base case. The location of the U.S. natural gas supply regions listed in Table 10-1.1 are shown in the map in Figure 10-1.1.

Table 10-1.1 Shale Gas Resource Base in Tcf (does not include proved reserves)

	AEO 2010[a] (as of BOY 2008)	EPA Base Case[b] (as of EOY 2010)	AEO Supply Case[b] (as of EOY 2010)
U.S.	**346.5**	**917.2**	**284.9**
Northeast	73.2	254.4	79.0
Gulf Coast	90.3	431.6	134.1
Midcontinent	51.0	132.9	41.3
Southwest	59.5	60.3	18.7
Rocky Mountain	21.6	37.7	11.7
West Coast	50.9	0.3	0.1
Canada	**NA**	**511.1**	**158.7**

[a] *Technically recoverable resources without reference to economic profitability.*

[b] *Economically recoverable resources under wellhead gas price of $14/MMBtu (2007 dollars).*

Figure 10-1.1 U.S. Supply Region