EMF 31 Scenario Design (June 27, 2014)

Scenarios for US and Global Models

This study design describes the assumptions for scenarios in the second round of EMF 31. US and North American models are asked to simulate the first four cases. Global models are asked to simulate case #1 (Reference), case #2 (Abundant US Resources), case #5 (High International Demand), case #6 (Oil-Indexed Pricing), and case #7 (Russian Supplies). Modelers are welcome to simulate other cases at their discretion.

Generally, do not override model results for endogenous variables or where you have strong priors. We are testing the model how you use it. Please document any major changes from these assumptions if you decide to override these guidelines.

Case #1: EMF Reference or Baseline

The EMF 31 Reference or Baseline scenario is patterned after the new Annual Energy Outlook 2014 Reference case that is available from the US Energy Information Administration at http://www.eia.gov/oiaf/aeo/tablebrowser/.

Modelers should consider using the AEO 2014 projections for world oil prices, U.S. economic growth and population trends, and current energy and environmental regulatory policies in-place at this time. The one exception will be regulations covering the electric power sector where noted below.

The case should incorporate the following assumptions for the power sector:

1) Calibrate to AEO 2014 power plant costs and fuel supply curves if you do not use your own estimates. Power plant cost assumptions for AEO2014, which are very similar to those for AEO2013, can be accessed at http://www.eia.gov/forecasts/aeo/assumptions/pdf/table8_2_2014er.pdf.

2) Following the AEO reference case, include CAIR and MATS, but not the non-air new EPA regulations (coal combustion residues, CWA Section 316(b)). Models that represent the retrofit/retire decision at a fine level of detail are requested to report gigawatts (GW) of retirements for use by more aggregate models. (If you agree to report detailed retirements, please let us know in advance.)

3) Include the proposed New Source Performance Standards (NSPS) for CO_2, which would have the effect of prohibiting new coal without CCS. These rules are not yet implemented.

Unless you are using your own natural gas supply estimates, please calibrate natural gas supply conditions to the price-production paths in AEO 2014 reference case as specified below in Table 1.

Global models should allow a steady decline in the share of natural gas sales under contracts that are indexed to oil prices in certain Asian economies and completely eliminate their effects by 2025. The Japanese delivered gas price is about $16 per mmbtu, or 87% of the Brent crude oil price ($107/B) in Btu terms. In the EMF reference case, modelers should steadily decrease the role played by oil indexation over time by either: (a) reducing the percentage of Japanese gas sales under oil-indexed pricing, or (b) reducing the gas price as a percent of the oil price under oil-indexed contracts. By 2025, please eliminate any oil-indexed contracts that maintain gas prices higher than market-determined prices. This assumption calls for gas-on-gas competition in all regions. If you are uncertain about the speed of this decline, please apply them uniformly each year. Please adjust other Asian contracts (Korea, India and

China) and those for Russian exports relative to these assumptions for Japan. Modelers are free to use their discretion in making these assumptions, which are offered as guidelines.

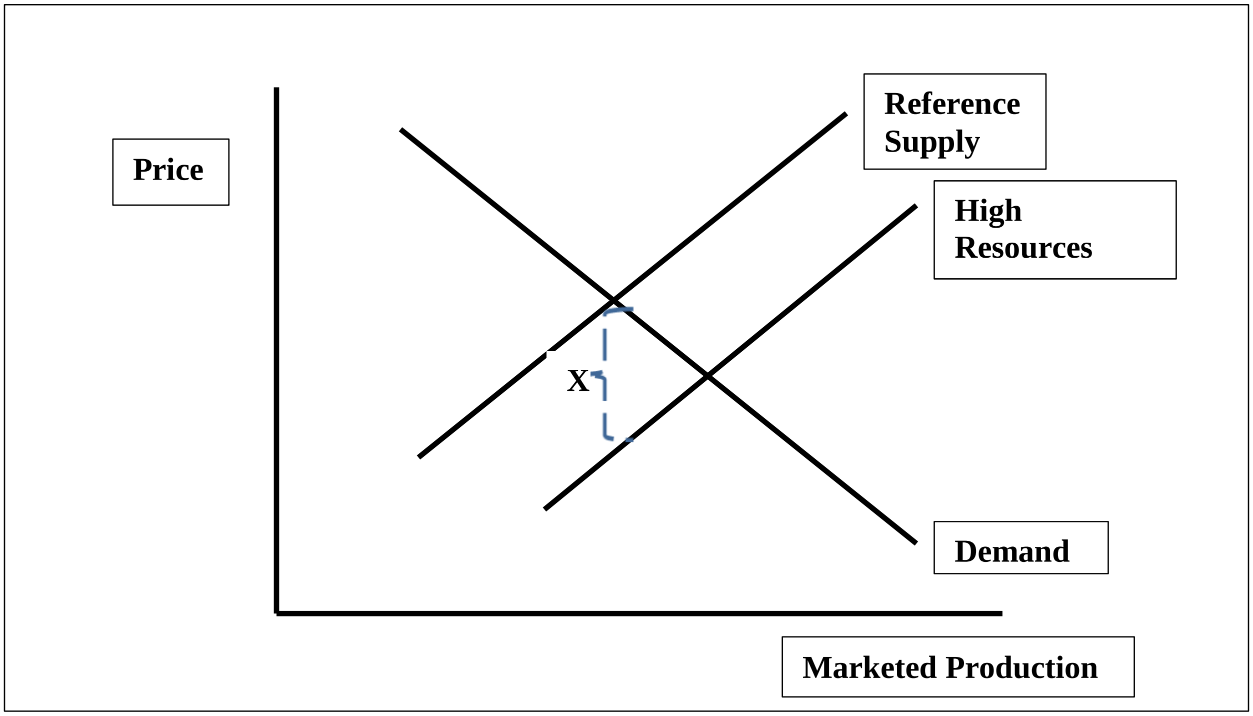
Table 1. AEO2014 Reference Natural Gas Supply Conditions

	Dry Gas Production (trillion cubic feet)	Henry Hub Spot Price (2012 dollars per thousand cubic feet)
2011	22.5	$4.07
2012	24.1	$2.75
2015	24.6	$3.74
2020	29.1	$4.38
2025	31.9	$5.23
2030	34.4	$6.03
2035	36.1	$6.92
2040	37.5	$7.65

Case #2: Abundant Resources

The EMF 31 Abundant Resources scenario reduces the costs of producing the same production levels in the reference case. If you have a spatially detailed natural gas supply model that differentiates shale and other unconventional sources from conventional ones, please follow the assumptions for resources and well spacing in the AEO 2014 High Resource case. Otherwise, please incorporate the Abundant Resource

Figure 1. Incorporating Cost Reduction in High Resource Case



case as a reduction in the inflation-adjusted (real) production costs for producing natural gas as shown in Figure 1. The cost of producing any natural gas production level in each year will be **x percent lower** than in the reference case. The first column of Table 2 shows the percent cost reduction. These cost reductions approximate the effect of high resources on the natural gas wellhead price relative to the reference case in AEO 2014. It is patterned after the deviation between the High Oil/Gas Resources and Reference cases in the new Annual Energy Outlook 2014 released by the US Energy Information Administration, also available at http://www.eia.gov/oiaf/aeo/tablebrowser/.

Table 2. Cost Reductions and Escalations in Scenarios #2 and #3

	Cost Reduction(%)	Cost Escalation(%)
2015	-9%	7%
2020	-10%	8%
2025	-12%	9%
2030	-30%	9%
2035	-33%	9%
2040	-40%	10%

Do not shift the supply curves for domestic oil in this EMF scenario. Modelers are invited to report a modeler choice case that allows shifts in both domestic oil and natural gas production curves. Allow more abundant natural gas resources to dampen world oil prices only if your model traces this effect endogenously.

For global models, please keep international supply and demand conditions (price-quantity curves) outside the United States unchanged.

Case #3: Cost Escalation

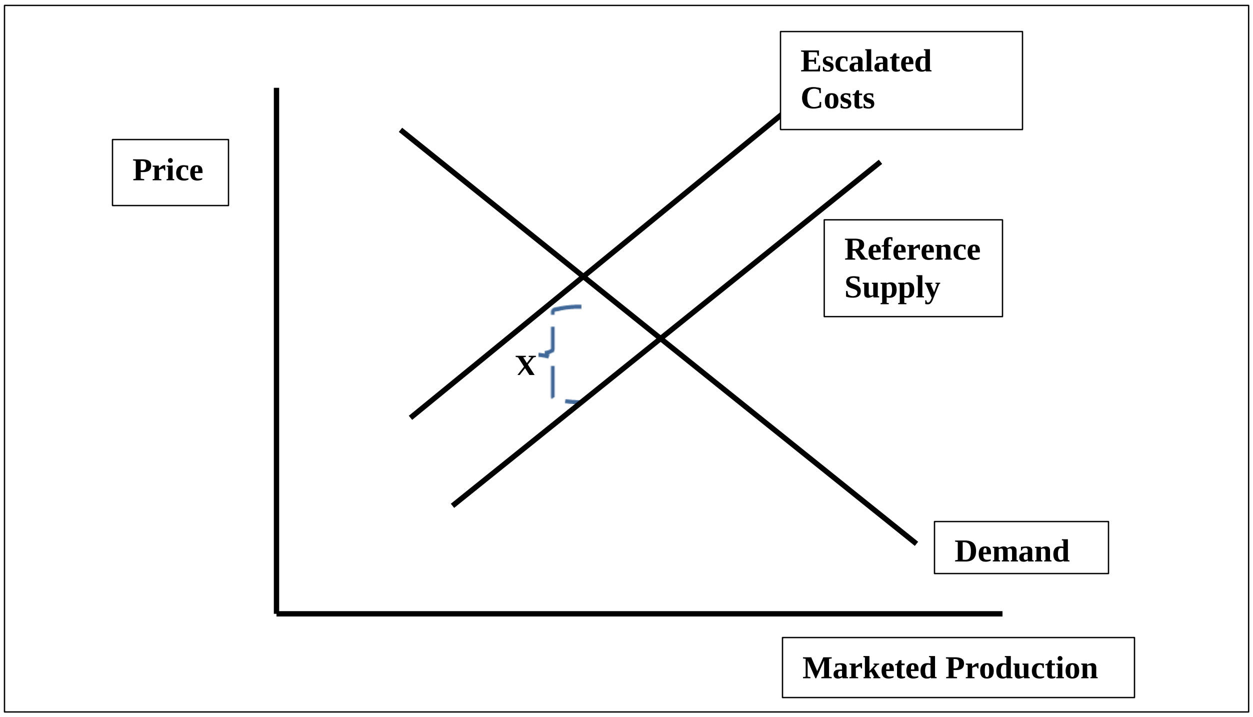
The EMF 31 Cost Escalation scenario will attempt to project conditions when federal, state and local governments impose additional production costs to meet a range of different social benefits that may be excluded from private transactions. These perceived benefits may include ensuring water availability, maintaining water quality, reducing emissions from methane and other pollutants, mitigating heavy truck congestion, providing social services, and controlling infringement on local zoning ordinances. The available evidence suggests that these costs will vary dramatically by region as some problems are much more prevalent in some regions than in others.

This scenario will be represented in highly aggregated terms but in a way that will reveal the approximate order of magnitude of how these considerations might influence future natural gas development. Some crude benchmark estimates suggest that these additional costs, in the aggregate, might amount to range between 25 to 80 cents per thousand cubic feet. Their effect per unit of production will be greater for wells with low productivity than for wells with high productivity.

Please incorporate the Escalated Cost case due to more stringent environmental, water and local community costs as an increase in natural gas production costs as shown in Figure 2. The cost of producing any natural gas production level in each year will be **x percent** higher than in the reference case. The second column of Table 2 shows the percent escalation in the inflation-adjusted costs. These cost escalations begin by increasing production costs by 25 cents per thousand cubic feet above the AEO reference path in 2015 and eventually increase costs by about 80 cents per thousand cubic feet above the AEO reference path in 2040. Please note that these additional expenses are compliance costs and may exceed or fall short of social damages associated with environmental or social externalities; this case is not normative.

Do not shift the supply curves for domestic oil in this EMF scenario. Allow more costly natural gas resources to raise world oil prices only if your model traces this effect endogenously.

Figure 2. Incorporating Cost Escalation in High Resource Case



Case #4: Technology Performance Standard

The purpose of this case is to evaluate how changes in the regulation of the power sector's carbon dioxide emissions will impact natural gas markets. This case is patterned after the recent EPA Clean Power Plan, although not all rules have been completely specified and considerable latitude exists in how each individual state will implement the plan within its borders. Modelers are requested to simulate a technology performance standard (TPS) for the electric power sector. The tradable emissions rate Performance Standard sets a fleet average CO_2 emissions rate standard (tons/MWh) across all existing and new fossil generators and allows trading of credits to achieve the standard. A generator earns (owes) a credit on each MWh of generation for each ton/MWh that its emissions rate is below (above) the standard. A TPS was selected for this case because of its relevance to ongoing EPA deliberations on an upcoming performance standard for existing plants, and because it will highlight coal-gas tradeoffs under a power sector carbon policy.

The TPS can be thought in three equivalent ways:

- a credit trading system in which generators are allocated credits based on the standard emissions rate and must hold enough credits to cover their actual emissions rate;
- a cap-and-trade policy that allocates emissions allowances to all generators on the basis of current period electricity production;
- a simultaneous tax on CO2 emissions at the current credit trading price and subsidy based on the standard emissions rate.

Details of policy implementation are as follows:

- The policy covers all new and existing powerplants beginning in the year 2020.
- The emissions rate target would have to be met on average across all of these plants, not by each individual unit.
- The national target CO-2 emissions rate for these plants should be set equal to 1076 pounds CO-2 per megawatt-hour for each year between 2020 and 2029.
- The national target CO-2 emissions rate for these plants should be capped at 1001 pounds CO-2 per megawatt-hour in 2030 (30 percent below the average emissions rate for carbon-generating plants in 2005).
- After 2030, the case assumes that new policies will be implemented such that the national target CO-2 emissions rate for these plants should decrease by 1% per year to reach a level of 819 pounds per megawatt-hour by 2050.
- Banking of credits for use in future periods is allowed by this policy.

Case #5: High International Demand

This case will expand international natural gas demand outside of the United States by the percentages shown in Table 2. These demand increments should be added to reference consumption levels at the reference price levels, i.e., they are shifts in the foreign demand curve. Demand levels after the model has achieved market equilibrium will most likely be lower than shown in the table as prices are likely to rise. Modelers can select how they want to distribute this global demand expansion by country or world region. Modelers should use these standardized demand shifts, although we intend to develop an interesting narrative that will describe what this scenario represents. For example, this scenario could represent a combination of these developments:

- Some nuclear plants in Japan and South Korea are displaced by combined-cycle natural gas plants.
- Some coal plants in China and India are displaced by combined-cycle natural gas plants.
- China and other Asian economies adopt more compressed natural gas vehicles than expected in the EMF reference or baseline case.

Table 2. % Deviation for High International Demand

	2015	2020	2025	2030	2035	2040
Demand Shock	2%	6%	8%	10%	12%	14%

Case #6: Oil-Indexed Pricing

This case evaluates the competitiveness of US natural gas exports when Japan and other relevant regions reduce their share of oil-indexed contracts less rapidly than in the reference case. Please reduce the contract decline process by a factor of two, such that all oil-indexed contracts are eliminated by 2035 rather than by 2025 in the reference case. Modelers are invited to submit other modeler choice scenarios applying different assumptions. Please document any key assumptions if you submit these additional alternative cases. All other assumptions should remain the same as in the reference case.

Case #7: Russian Supplies

This case evaluates the opportunities for U.S. natural gas exports when some Russian natural gas supplies are more costly or constrained by limited investment. Modelers are asked to represent the following conditions:

(1) resources in the Yamal Peninsula and Kara Sea become more costly, effectively rendering it unattractive to foreign capital and removing it from the mix of Russian supplies that could economically reach the market, and
(2) the available capacity of pipleines through Ukraine is phased out to reflect a preference of European consumers to seek alternative routes, including other commercial avenues for Russian gas to reach Europe.

This scenario may require further standardization once modelers begin to simulate these conditions. Please contact EMF staff if you would like further advice on incorporating these assumptions.

Measured Costs

Please indicate whether you can report the costs (benefits) of an alternative case (policy or supply conditions) relative to the reference case. Please describe how costs are computed and what they represent. For example, a model may estimate costs in one of several ways:

- the social welfare costs attributable to changes in consumer and producer surpluses;
- the loss in aggregate economic consumption of all goods and services;
- the additional costs associated with the power sector's generation costs;
- changes in consumer energy expenditures;
- changes in gross domestic product; or
- an alternative metric that is not included in the above list.

Output Variables:

Modelers are requested to submit results by November 7 in order that EMF staff can review results for any inconsistencies prior to the December meeting. Please report results from each scenario covering the 2015-2050 period in a worksheet provided my EMF. The list below includes <u>one additional variable</u> (highlighted in yellow) in addition to those variables requested in the first round. Please report any variables that you can from the following list:

Sector	Variable	Units	Additional Notes	2012(EIA)
Consumption	Liquids	Quad BTU	See Table AEO, A2. Includes Liquefied Petroleum Gases and Other, E85,Motor Gasoline, Jet Fuel, Kerosene, Distillate Fuel Oil, Residual Fuel Oil, Petrochemical Feedstocks, and Other Petroleum.	35.87
Consumption	Natural Gas	Quad BTU	Includes Pipeline Fuel and Lease and Plant Fuel.	26.20
Consumption	Coal	Quad BTU		17.34
Consumption	Nuclear	Quad BTU		8.05
Consumption	Renew ables	Quad BTU	Includes hydroelectric, geothermal, w ood and w ood w aste, biogenic municipal w aste, other biomass, w ind, photovoltaic, and solar thermal sources.	6.65
Consumption	Total Primary	Quad BTU	Also includes Biofuels Heat and Coproducts, Renew able Energy, Liquid Hydrogen, Non-biogenic Municipal Waste, and Electricity Imports	95.02
Industrial	Liquids	Quad BTU	See Table AEO, A2. Includes Liquefied Petroleum Gases and Other, Motor Gasoline, Distillate Fuel Oil, Residual Fuel Oil, Petrochemical Feedstocks, and Other Petroleum.	8.06
Industrial	Natural Gas	Quad BTU	Excludes Pipeline Fuel and Lease and Plant Fuel.	7.29
Industrial	Coal	Quad BTU		1.48
Industrial	Renew ables	Quad BTU		1.48
Industrial	Electricity	Quad BTU		3.35
Industrial	Total Delivered	Quad BTU		23.63
Electricity	Natural Gas	Quad BTU		9.46
Electricity	Coal	Quad BTU		15.82
Electricity	Nuclear	Quad BTU		8.05
Electricity	Renew ables	Quad BTU		4.59
Electricity	Total	Quad BTU		38.53
Electricity	Total Sales	BKw H	Retail Sales to Ultimate Customers	3,694.65
Residential	Natural Gas	Tcf	Divide Quad BTU by 1.022	4.17
Commercial	Natural Gas	Tcf	Divide Quad BTU by 1.022	2.90
Industry	Natural Gas	Tcf	Divide Quad BTU by 1.022. Excludes Pipeline Fuel and Lease and Plant Fuel.	7.14
Electric	Natural Gas	Tcf	Divide Quad BTU by 1.022	9.25
Transportation	Natural Gas	Tcf	Divide Quad BTU by 1.022. Gas used in motor vehicles, trains, and ships.	0.04
Total Consumptio	Natural Gas	Tcf	Divide Quad BTU by 1.022. Includes Pipeline Fuel and Lease and Plant Fuel.	25.64
Production	Natural Gas	Tcf	Marketed production (w et) minus extraction losses.	24.06
LNG Net Exports	Natural Gas	Tcf	Exports minus Imports	(0.15)
Mexico Net Expo	Natural Gas	Tcf	Exports minus Imports	0.62
Canada Net Expc	Natural Gas	Tcf	Exports minus Imports	-1.99
Total Net Exports	Natural Gas	Tcf	Exports minus Imports	-1.51
Price	Henry Hub	2012$/mmbtu	Excludes any carbon fees	2.75
Price	Brent Oil	2012$/barrel	Excludes any carbon fees	111.65
Price	Coal Minemouth	2012$/ton	Excludes any carbon fees	39.94
Price	Electricity	2012 cents/kw h	All sectors; excl. carbon fees	9.84
Economy	Real GDP	Billion 2005$		13,593.20
Economy	Economic Cost	Billion 2005$	Costs w /r to Reference	0.00
Economy	Carbon Dioxide Emissions	Million Metric Tons	Total Energy-Related (all sectors)	5,289.86
Electricity	Sulfur Dioxide Emissions	Million Short Tons	Electricity only	3.34
Electricity	Nitrogen Oxide Emissions	Million Short Tons	Electricity only	1.68