August 07, 2012

MEMORANDUM FOR:	JOHN CONTI ASSISTANT ADMINISTRATOR FOR ENERGY ANALYSIS ANGELINA LAROSE TEAM LEADER NATURAL GAS MARKETS TEAM JOHN STAUB TEAM LEADER EXPLORATION AND PRODUCTION TEAM
FROM:	EXPLORATION AND PRODUCTION and NATURAL GAS MARKETS TEAMS
SUBJECT:	First AEO2013 Oil and Gas Working Group Meeting Summary (presented on 07-31-2012)

Attendees:

Anas Alhajji (NGPTRS)	via WEBEX
Sara Banaszak (ExxonMobil)	via WEBEX
Stephen Beck (PFC Energy)	via WEBEX
Sandeep Bhakhri (EOG Resources)	via WEBEX
Kara Callahan (OnLocation, Inc.)	via WEBEX
Evelyn Dale	via WEBEX
Aloulou Fawzi (EIA)	via WEBEX
Michelle Foss (Univ of Texas, Houston)	via WEBEX
Tim Grant	via WEBEX
Gurcan Gulen (Univ of Texas, Austin)	via WEBEX
Bob Hugman (ICFI)	via WEBEX
Eric Kuhle	via WEBEX
Beth Lau (CAPP)	via WEBEX
Carol Lenox (EPA)	via WEBEX
David Schmalzer (cox.net)	via WEBEX
Charlie Sheppard (EOG Resources)	via WEBEX
Peter Balash (NETL)	via WEBEX
Joseph Dipietro (NETL)	via WEBEX
Ken Kern (NETL)	via WEBEX
Gavin Pickenpaugh (NETL)	via WEBEX
Charles Zelek (NETL)	via WEBEX
Justine Barden (EIA)	
Joe Benneche (EIA)	

Geoffrey Brand (API)
Philip Budzik (EIA)
David Daniels (EIA)
Cory Gill (Goldwyn Global Strategies)
Ehsan Khan (FE)
Angelina LaRose (EIA)
Taylor Malone (adv-res)
Phyllis Martin (Self)
Moses McCall (EIA Intern)
Chetha Phang (EIA)
John Pyrdol (FE)
Jeff Quigley (EVA)
David Shin (API)
John Staub (EIA)
Peri Ulrey (NGSA)
Dana Van Wagener (EIA)
Jose Villar (EIA)

Presenters: Phil Budzik, Dana Van Wagener, Joe Benneche

Presentation: The presentation provided an overview of the primary assumption changes under consideration for *AEO2013* in the Oil and Gas Supply Module (OGSM) and the Natural Gas Transmission and Distribution Module (NGTDM). For offshore oil and gas supply modeling the following was presented: the schedule for new leasing in currently restricted areas, key assumptions on deepwater projects already discovered, and technically recoverable resources by region. For enhanced oil recovery (EOR) modeling the following assumptions were presented: the level of recoverable EOR resources by recovery method and price, CO_2 availability by source type, and the location of current and potential CO_2 EOR projects. The majority of the discussion was on the setting of and values to be used for the estimated ultimate recovery levels for continuous plays. For the NGTDM the discussion topics included: the move from basing the model on wellhead prices to spot prices, the new set of assumptions for pricing natural gas for vehicles, and the modeling and assumptions related to endogenously representing LNG exports of domestically produced natural gas. We mentioned that we are on a much reduced schedule this year and did not propose additional runs or Issues and Focus articles, but still asked for suggestions. Most of the non-clarifying questions and comments follow, with a summary of our responses:

Questions and answers regarding the OGSM:

1) What are you projecting different this year for oil production in Alaska, particularly offshore?
<u>EIA response</u>: There is no change from AEO2012 because there has been no new information regarding the oil and gas resource potential of offshore Alaska. However, if Shell were to discover a large oil field under the gas at the Berger prospect, then EIA

would re-evaluate the prospects for finding larger offshore Alaska oil fields than are currently represented in the model.

2) For tight oil and shale gas well decline rates, are you spot checking with producers or looking at actual data?
EIA response: EIA analyzes actual production data on a well-by-well basis. However, wells with less than 6 data points are eliminated from the analysis because the shape of the decline curve over the long-term cannot be specified with any certainty with only a few data points.

3) How are you dealing with lags in reporting of production data?
EIA response: For shale gas production we use Lippman Consulting's analysis to estimate dry shale gas production for key plays in the United States and for the total U.S. For all other oil and natural gas production at the well level we rely on data gathered by HPDI Inc and state governments. State governments vary in the timeliness of the data that they provide to the public. Because there is nothing EIA can do regarding the State reporting delays, all EIA can do is ensure that it is using the latest data that has been made available to the public by the States.

4) How are lease condensates and Associated Dissolved (AD) natural gas accounted for?
EIA response: Lease condensates are included with crude oil. AD gas (i.e. gas from oil wells) is included in the natural gas production. Likewise, liquids from wells classified as natural gas wells are put in the "natural gas plant liquids" category.

5) Are you distinguishing kerogen?
EIA response: Yes, "oil shale" that is produced from kerogen is treated separately in the model from "shale oil" which EIA refers to as "tight oil" because of the frequent confusion in names. We do not foresee any large-scale production of oil shale from kerogen during the AEO time horizon because of the short payback period and high rates of return on tight oil wells, relative to the large investments, long time delays, and low rates of return associated with oil shale production from kerogen.

6) Do your EURs make a distinction between horizontal and vertical wells, how do you reflect what has been occurring? The different types shouldn't be mixed. What is the mix of well types (vertical/horizontal/directional)?
EIA response: EIA analyses the vertical and horizontal well production data separately. In modeling future year drilling activity, EIA assumes that the type of wells drilling in future will reflect the current mix of horizontal and vertical wells being drilled today.

7) Are you including proved shale gas in these numbers?
EIA response: Not in this presentation. The EIA proved oil and gas reserves report will be coming out soon. The EIA models will be updated to reflect the latest EIA oil and gas reserve volumes.

8) A lot of other people are showing a much higher TRR, how does your view differ, what is the justification?

EIA response: EIA's TRR estimates are based on existing well production profiles. TRR estimates give a context for the relative magnitude of the resource base, but there is a lot of uncertainty regarding these estimates. EIA's TRR estimates will change as new well production data becomes available. In the AEO2012, EIA ran sensitivity cases to explore the impact of different resource sizes on future oil and gas production, consumption, and prices. EIA's modeling efforts are primarily focused on the economics of producing oil and gas, which doesn't focus on TRR per se, but rather on well production curves and well drilling and completion costs. EIA's ultimate responsibility in the Annual Energy Outlook is to project the equilibrium of production, consumption, and prices. To do that, EIA models the competition between individual wells across all of the resource types and petroleum basins on a discounted cash flow basis.

9) If USGS does an assessment do you use it?
EIA response: When the USGS makes their continuous resource assessment data available, EIA uses as much of it as possible, including: the areal extent of the formation, well spacing, percent of the total area that has potential, etc. The primary obstacle has been that the USGS has not published much of its detailed assessment data.

10) What well spacing do you use and how is it derived?
EIA response: Well spacing is specific to each formation and depends on information obtained directly from producer reports and presentations and from the USGS oil and gas resource assessments, when this data is available.

11) Have you incorporated the new information that has come out recently regarding the Bakken formation being potentially more gas prone?
EIA response: The large continuous formations are divided into subregions. The wells within each subregion are assigned an average oil-gas ratio, based on the average oil-gas ratio determined for the existing wells producing within that region.

12) What made the Niobrara area TRR increase from last year's AEO? Are you seeing lower EURs but higher TRRs in the Bakken and Niobrara?
EIA response: For the continuous formations, TRR estimates are primarily a function of the formation's areal, well spacing, and well EUR. The change in the Niobrara's TRR was largely due to expanding the areal extent of the Niobrara, which is found in many of the Rocky Mountain petroleum basins.

13) Do the Deep Bossier play well decline curves fall off rapidly?
EIA response: In the OGSM model, the Deep Bossier tight gas and the adjacent Haynesville gas shale play are treated as a single formation. Wells in both formations exhibit a rapid decline in gas production rates after high initial production rates. So an average well decline profile is used for the combined formations, which has a high initial production rate followed by a rapid decline.

14) How are you incorporating the variations over time regarding well drilling and completion costs?
EIA response: Historically, changes in well drilling and completion costs have followed the changes in oil and gas prices. The OGSM model reflects this historical relationship, wherein the model's well drilling and completion costs are both a function of oil and gas price levels and the well design (e.g., vertical depth, length of the horizontal lateral, and the number of fracturing stages).

15) Are average EURs really representative?
EIA response: Average well EURs are representative of the existing wells within the each formation's subregion. During the AEO2013 cycle, EIA will be examining the EUR variation within each continuous formation to better refine the number and areal extent of the subregions within each formation, so that regional variation in well EUR is better represented in OGSM.

16) Does using the total population of wells cause EURs to be artificially low (including dry holes)?
EIA response: Generally, using the total population of wells to derive EURs provides the best representation of what producers are likely to witness when drilling new wells. Dry-holes, however, are not explicitly represented within the model because they do not result in a production decline curve, and consequently, are not used in generating an average well production decline curve that is the basis for determining an average EUR.

17) It would be helpful to see a supply curve showing how much resource would be available at what cost.
EIA response: Supply curves are a static representation of what is a very dynamic situation. Drilling and completion costs change not only due changes in technology and management practices, but also reflect a specific oil and gas price level. Another conundrum associated with such curves is the co-production of oil, gas, and NGL, and the assignment of drilling and completion costs to each product. This is a critical issue because oil, gas, and NGL are frequently co-produced by a well. Although a supply curve might be interesting, it could also be misleading due to the numerous assumptions that are required to generate such a curve.

18) With such low EURs, could it reflect the many nonperformers and should it? Some of these seem to be too low to be economic.
EIA response: Within continuous formations, neighboring well production rates can vary by as much as a factor of three. Studies of Barnett gas wells indicate that at gas prices of around $7/MMBtu as many as 20% of the wells might have been unprofitable. Even so, the unprofitable wells will be produced so long as their revenues exceed operating costs; consequently, few such wells are plugged and abandoned early. Producers drill new wells based on an expected average EUR knowing that if they drill a large enough number of wells over time they will realize recovery rates that are consistent with the average EUR.

19) Does drilling to hold leases lead to too many dry holes or nonperforming wells and push down EURs? Do producers abandon marginal acreage and return back to sweet spots? How would that be captured?
EIA response: Drilling to hold leases should not significantly affect the average well EUR. If a producer drills leasehold acreage that proves to be unproductive and unprofitable, the producer has no financial incentive to drill many wells in that acreage. In contrast, producers have a large financial incentive to drill the greatest number of wells where they expect to realize the highest production rates and profits. Consequently, it would be expected that only a small proportion of the total wells drilled in a formation would be deliberately drilled in unproductive and unprofitable acreage and this small proportion would have a correspondingly small impact on the average EUR.

20) Good idea to be more explicit about assumptions that are erring on the conservative side. What is the benefit of being conservative?
EIA response: EIA's methodology of determining average well EURs is based on existing well production performance. As such, this methodology neither under estimates nor over estimates a formation's productive potential, based on what is known today. Although these estimates might be viewed in the future as being conservative due to future improvements in technology and management practices, it would be inappropriate to assume a more optimistic approach to estimating well EURs and formation TRRs that might not be realized in the future.

21) In a future workshop, the group would like to see how model makes the linkage to profitability. How does the model pull in prices and costs? At what point do technically recoverable resources become economic?
EIA response: The EIA energy models are fully documented and that documentation is available on the EIA website for those parties who are interested in better understanding the interrelationship between oil and gas resources, their production costs, and the development of new productive capacity.

22) Where do side case topics come from? Congress? Suggest something on relationships between natural gas and NGL volumes across plays, as well as infrastructure issues (gas and NGL).
EIA response: Generally, the EIA performs side cases on those attributes of the model that have the greatest uncertainty (e.g., continuous oil and gas resources) or the greatest potential impact. Some side cases are performed with respect to proposed changes in Federal law, policy, and regulation that have not been enacted.

Questions and answers regarding the NGTDM:

1) Is EIA modeling the situational relationships of natural gas vehicles and natural gas stations? For example, is EIA modeling designated natural gas transportation corridors, such as the Texas Clean Energy Triangle?
EIA response: Neither fueling infrastructure nor "transportation corridors" are explicitly modeled in NGTDM. In NGTDM, costs associated with fueling infrastructure are

included in the retail markup of the natural gas vehicle fuel price. EIA bases this markup off the capacity, utilization, capital costs and operating costs for an “average” station.

2) Although EIA’s equation for estimating the market price of natural gas in Europe and Japan seems to be “on the right track” and “a good idea”, the most critical factor in that equation seems to be the flexible LNG. For your estimated natural gas market price for Europe and Asia, where are you getting the flexible LNG data?
   EIA response: EIA is reviewing publicly available information regarding LNG contract ending dates, as well as analyzing industry reports on the levels of flexible LNG historically/currently traded. EIA will consider these factors and use analyst judgment.

3) Particularly in the European market, seasonality plays an important role in market prices. For your estimated natural gas market price for Europe and Asia, are you looking at those markets on monthly or annual basis?
   EIA response: In the statistical analysis that helped define the equation, EIA used monthly data. However, in the NGTDM model, the equation will be run based on annual data.

4) For the assumed LNG transportation rates, are you factoring in the cost of the Suez Canal toll for your rates from the Northeast United States to Japan?
   EIA response: EIA’s estimated LNG transportation costs take into consideration the Suez Canal toll, as well as the added travel costs if a tanker did not pass through the Canal.

5) Have we considered adjusting are Mexican exports, which could grow substantially?
   EIA response: EIA was not planning on making any significant changes to our basic modeling approach and assumptions for Mexican exports for AEO2013, but we’ll take a closer look.