Council of Canadians
Response to
Union Gas Limited Interrogatory # 1
(Mr. Hughes)

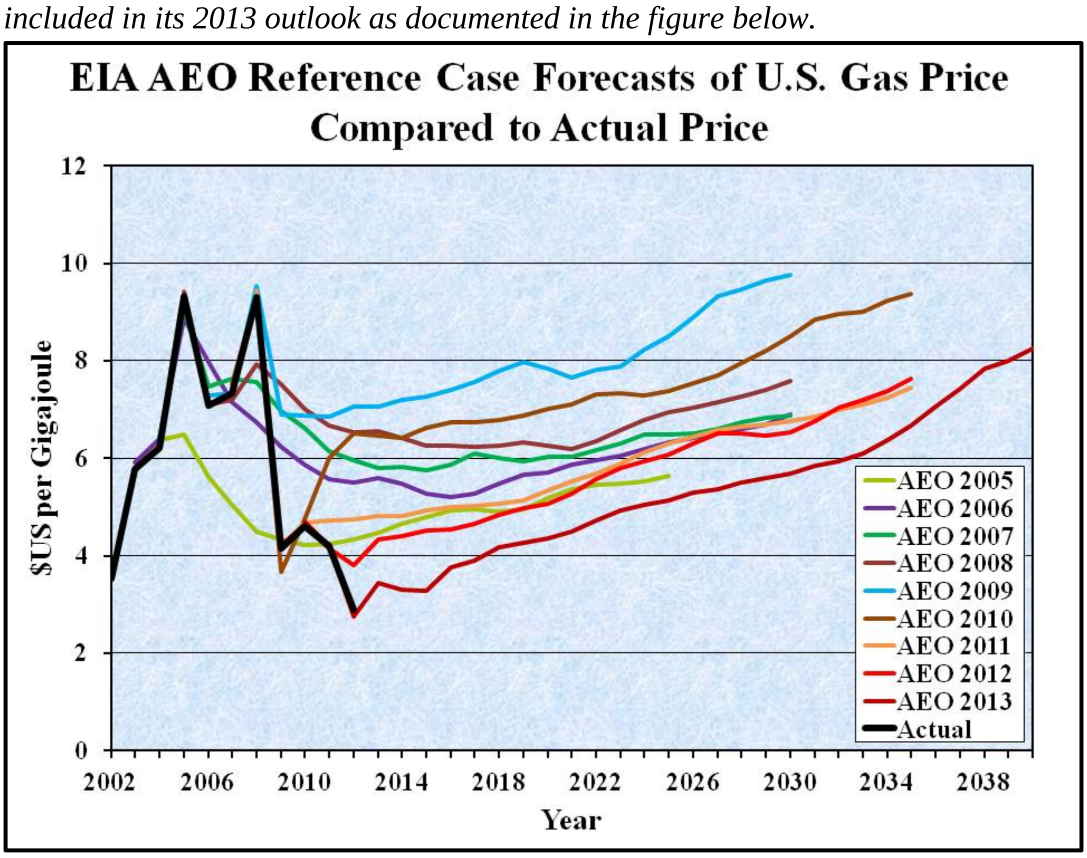
7. *Reference:* Exhibit L.EGD.COC.3, page 12 (Conclusion)

Request:

a) What is your price forecast for Marcellus shale gas? Has this forecast been filed in any other regulatory proceeding? If so, which? How does the price forecast compare to projected prices for WCSB?

Response:

I have not prepared a price forecast for Marcellus shale gas. However the geological characteristics of shale plays, including the Marcellus, suggest that it is likely to be considerably higher than that of the commonly used reference case forecast of the U.S. Energy Information Administration (see table of Henry Hub prices from the U.S. Energy Information Administration's Annual Energy Outlook 2013 filed as part of my response to the Enbridge Interrogatories). In fact, the EIA itself has in the past forecast much higher prices than are included in its 2013 outlook as documented in the figure below.



> *For reasons related to the declining productivity of shale gas plays, I also expect a return to the volatility in natural gas prices seen in the last decade as the drilling treadmill required to maintain shale production accelerates. The reference price forecast at Henry Hub of the National Energy Board in its latest "Canada's Energy Futures: Energy Supply and Demand Projections to 2035" http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2011/nrgsppldmndprjctn2035-eng.pdf is also lower than the prices I anticipate for the reasons already noted.*

8. *Reference:* Exhibit L.EGD.COC.3

Request:

a) Are the potential impacts described in the referenced evidence related to the US shale plays an issue for the WCSB shale? What is the potential impact to WCSB supplies going forward?

Response:

> *See Response to EGD-COC 2(a), (b) and (c). It is also important that WCSB shale plays are in a much earlier phase of development, and hence any common characteristics are likely to play out at a later date. In my view, increasing WCSB gas production will require considerably higher prices than the NEB forecasts in its reference case in the figure above.*

9. *Reference:* Exhibit L.EGD.COC.3

Preamble: In Union's Application Summary for the Brantford-Kirkwall/Parkway D Compressor Application (EB-2013-0074, Section 1 Page 1 of 7), Union states that "incremental demand for Dawn-Parkway transportation capacity and for transportation capacity downstream of Parkway for eastern markets" is supported by "increased access to the liquid market, diverse natural gas supplies and premium storage facilities at the Dawn Hub". The Dawn Hub has access to multiple supply basins throughout North America, of which the Marcellus/Utica shale is just one.

Request:

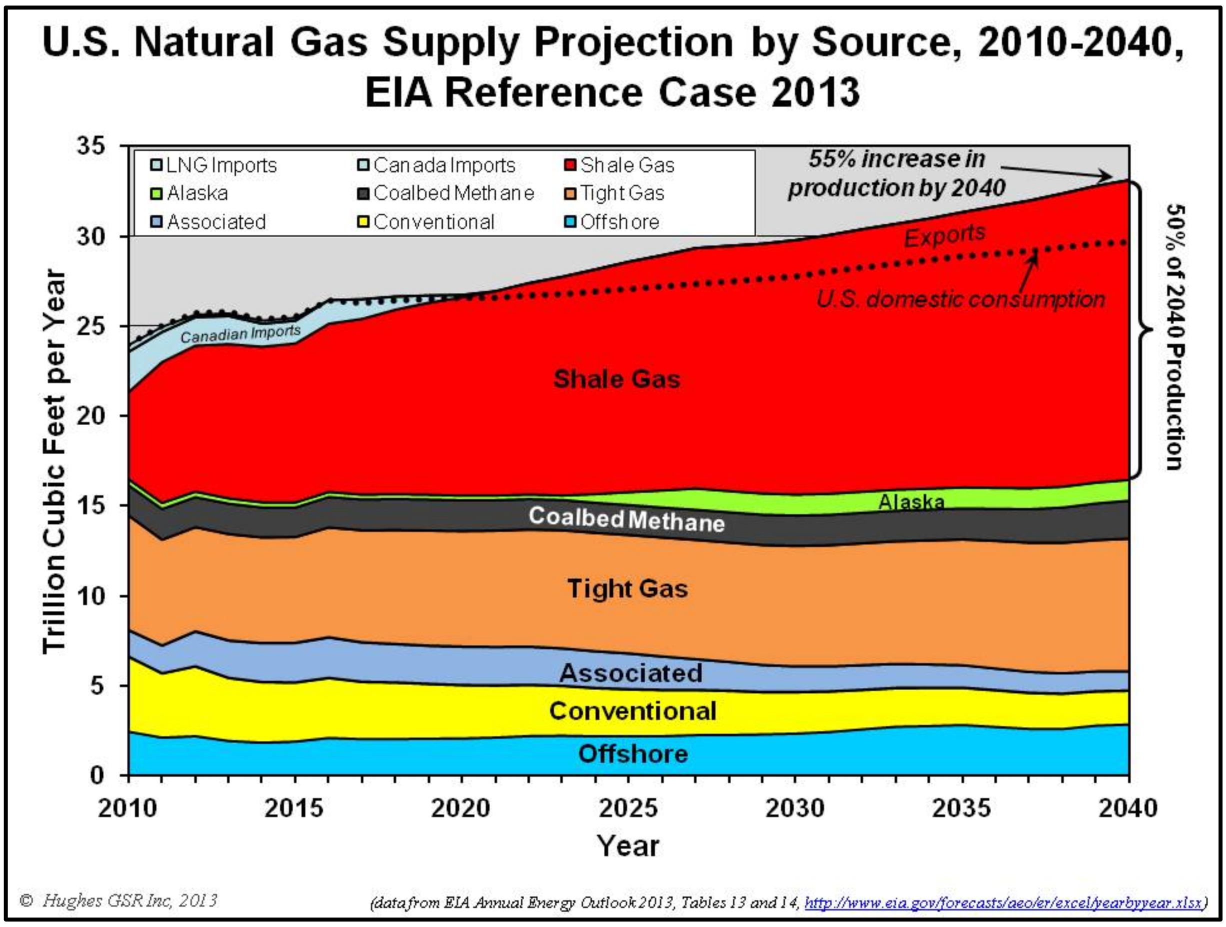
a) Were the long term viability and prices of other supplies coming into Dawn evaluated, or just shale gas? Has it been filed in other regulatory proceedings, if so which?

Response:

> *The long term viability of shale gas was principally evaluated as it is the sole driver of growth in supply (and hence low prices) according to the reference case forecast of the Energy Information Administration's Annual Energy Outlook 2013 illustrated in the figure below. Shale gas is projected to grow 100 percent from 2012 levels by 2040, and to comprise 50 percent of a greatly expanded supply by 2040. There is essentially no growth in the collective supply from all other*

U.S. gas sources in this forecast making the medium and long term prospects for shale gas critical in understanding the viability of this supply forecast and price projections. Furthermore shale gas, including the Marcellus/Utica from the northeast U.S., was identified as a major developing supply source in the Union application (reference EB-2012-0433, Page 26 of 121, Paragraph 22 – see also Paragraph 23 on Pages 27-28, and subsequent paragraphs).

The evidence provided in my submission has not been filed in other regulatory proceedings.



10. *Reference:* Exhibit L.EGD.COC.3 Page 2: "High well decline rates, ranging from 77%-89% over three years with an average of 84%. This necessitates high levels of drilling and capital expenditure to maintain, let alone increase, production."

Request:

i) For each shale play in North America, please provide the level of drilling and capital expenditures required to maintain gas production in light of the three year decline rates identified in your report

a) Does this estimate fall within the bounds of feasibility in each shale region?

Response:

Please see estimates for the top 14 shale gas plays in the U.S. in the table below (I have not yet published similar estimates for Canada where shale gas plays are in a much earlier stage of development). These estimates were based on the determination of overall field decline rates per year for each play and the number of wells required to make up that production loss assuming the first year production of new wells would be maintained at 2011 rates (ie. no decline in well productivity as drilling moved out of sweet spots). The data used in the table are current to mid-2012 so that in the case of the Marcellus, given increases in production since then, annual capex would now be larger than indicated in the table (currently estimated at 804 wells at a cost of $5 million each for a total yearly capex input of $4.022 billion based on yearend 2012 data).

Whether this falls within the bounds of feasibility depends entirely on economics. In mature dry gas plays, such as the Haynesville, this level of capex is not economic and production is falling. In young plays such as the Marcellus where sweet spots are still being drilled off it is feasible to drill enough wells to both offset declines and increase production. In shale oil plays with associated gas the oil carries the economics and therefore is feasible.

Annual Capex Required to Offset Overall Annual Decline by Shale Play

Field	Rank	Number of Wells Needed Annually to Offset Decline	Approximate Well Cost (million $US)	Annual Well Cost to Offset Decline (million $US)
Haynesville	1	774	9.0	6966
Barnett	2	1507	3.5	5275
Marcellus	3	561	4.5	2525
Fayetteville	4	707	2.8	1980
Eagle Ford	5	945	8.0	7558
Woodford	6	222	8.0	1776
Granite Wash	7	239	6.0	1434
Bakken	8	699	10.0	6990
Niobrara	9	1111	4.0	4444
Antrim	10	~400	0.5	200
Bossier	11	21	9.0	189
Bone Spring	12	206	3.7	762
Austin Chalk	13	127	7.0	889
Permian Delaware Midland	14	122	6.9	842
Total		**7641**		**41829**

© Hughes GSR Inc, 2013 *(well cost data from various sources and is approximate)*

Request:

i) What is the trend in well cost per completion in shale gas wells from 2006 through 2012? a) How will continued technological advancements affect future costs per well completion?

Response:

> *The trend in well cost is generally down over the 2006-2012 period. How much this can be improved in the future is speculation.*

Request:

i) What is the trend in days required to drill an individual shale gas well for the period of 2006 to 2012?

a) What is the impact of fewer days required per well on the cost per well completion?

Response:

> *The trend is for the number of drill days per well to decrease which is part of the reason for the trend in decreasing well costs as previously stated.*

Request

i) Has year over year Marcellus shale gas production increased from 2006 through 2012? a) If yes, did the growth in production require increases in natural gas prices in in the Marcellus region?

Response:

> *The Marcellus has grown in production over the 2006-2012 period. In fact the play didn't exist in 2006, and most of the production growth has occurred since the beginning of 2009. As clearly outlined in the evidence I submitted, the Marcellus is a new play and, as with all shale gas plays, production rises rapidly as sweet spots are defined and better technology is applied. Much of this production growth is due to a drilling boom to meet leasing commitments and competition to find and develop the sweet spots and was irrespective of gas price. As also clearly pointed out in my evidence, the Marcellus is highly unlikely to escape the production trajectory (growth – peak-decline) of more advanced shale gas plays such as the Barnett and Haynesville.*

11. *Reference:* Exhibit L.EGD.COC.3 Page 2: "Four of five shale gas plays comprising 80% of shale gas production in the U.S. are in or near decline."

Request:

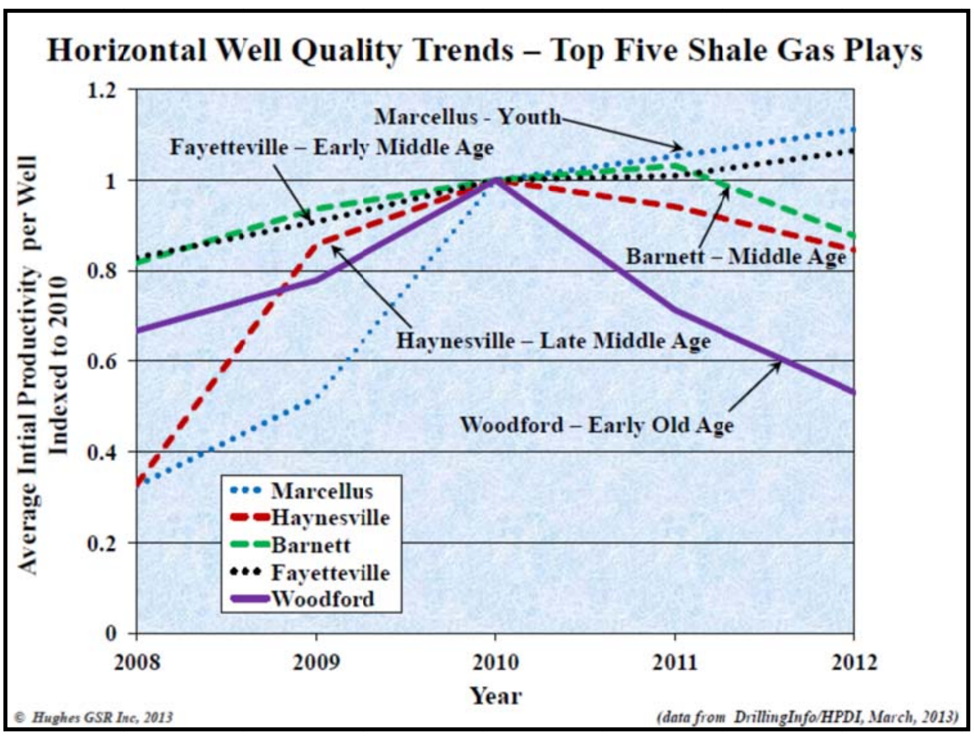
i) Please provide Estimated Ultimate Recovery (EUR) per well for the shale plays described in the above reverence for the years 2006 through 2012.

a) How does technology improvement impact the EUR per well in shale gas development?

Response:

Several of these five shale plays did not exist in 2006. The initial productivity (IP) of a well is an indication of how much gas that well will produce over its lifetime (estimated ultimate recovery or EUR).

As pointed out in my evidence, the average IP increases early in the life of a shale play as sweet spots are defined and better technology is applied. See Figure 8 – Exhibit L.EGD. COC 3 reproduced below. In the early phases of development average IP (as a proxy for EUR) increases rapidly. In three of these plays average IP peaked in 2010 or 2011 and has declined since. This proves that better technology is having no effect and sweet spots are becoming saturated with wells so that average well quality is declining due to the fact that lower quality reservoir rock is being drilled.



Request:

b) How has technology improvement affected the completions per well?

Response:

Technology improvement includes longer horizontal laterals, more frack stages per well, more wells per pad etc. The point is that this improvement is having no effect on average well quality *in mature fields, and in fact average well quality is declining meaning that even more wells will have to be drilled to offset intrinsic field declines, regardless of technology improvements.*

Request:

c) How has technology improvement affected the drilling and completion cost per well?

Response:

See Response to UGL_COC 10ii

Request:

ii) In the four shale plays that are at or near decline, please provide well completion totals for each year 2006 through 2012.

Response:

The four plays referred to in this question are the Barnett, Fayetteville, Haynesville and Woodford. The number of operating wells added per year for the 2006 to 2012 period for these plays is included in the following table.

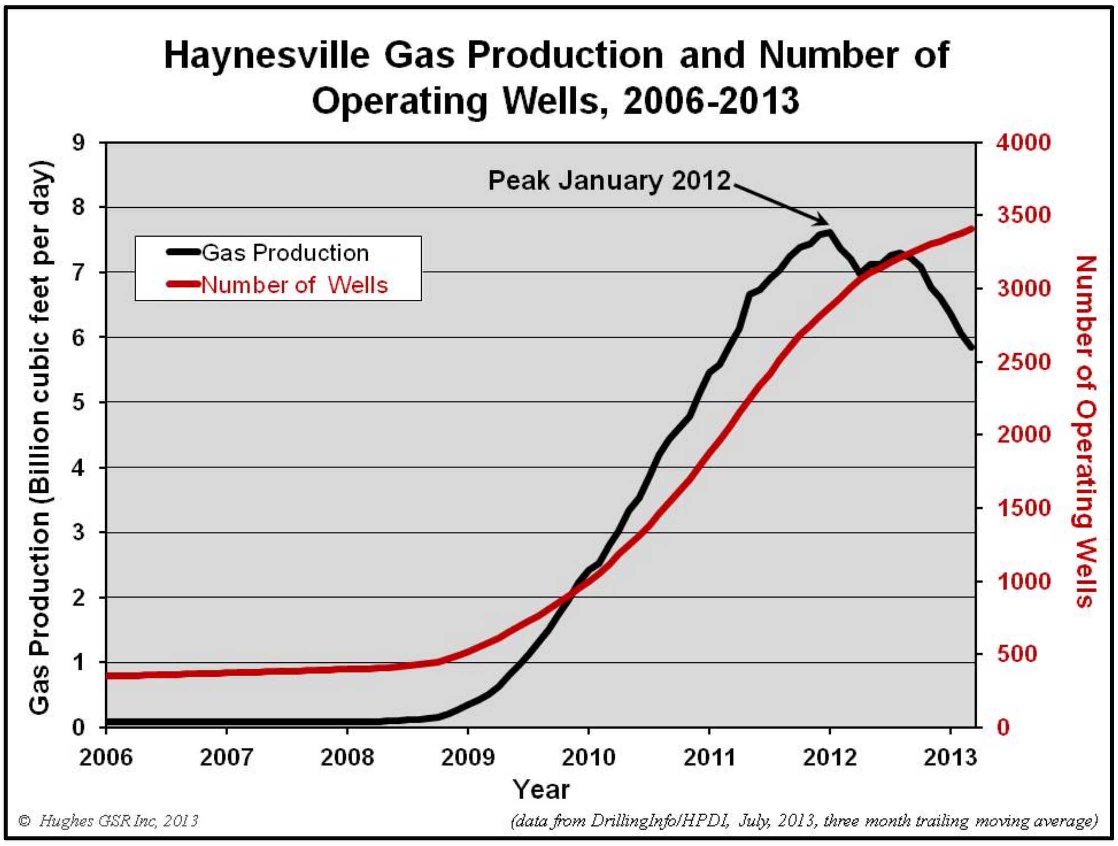
Wells added per year by Play				
	Barnett	Fayetteville	Haynesville	Woodford
2006	1404	101	17	102
2007	2249	370	26	263
2008	2763	640	94	424
2009	1066	795	462	329
2010	1528	848	830	321
2011	1392	787	1028	320
2012	704	591	514	421

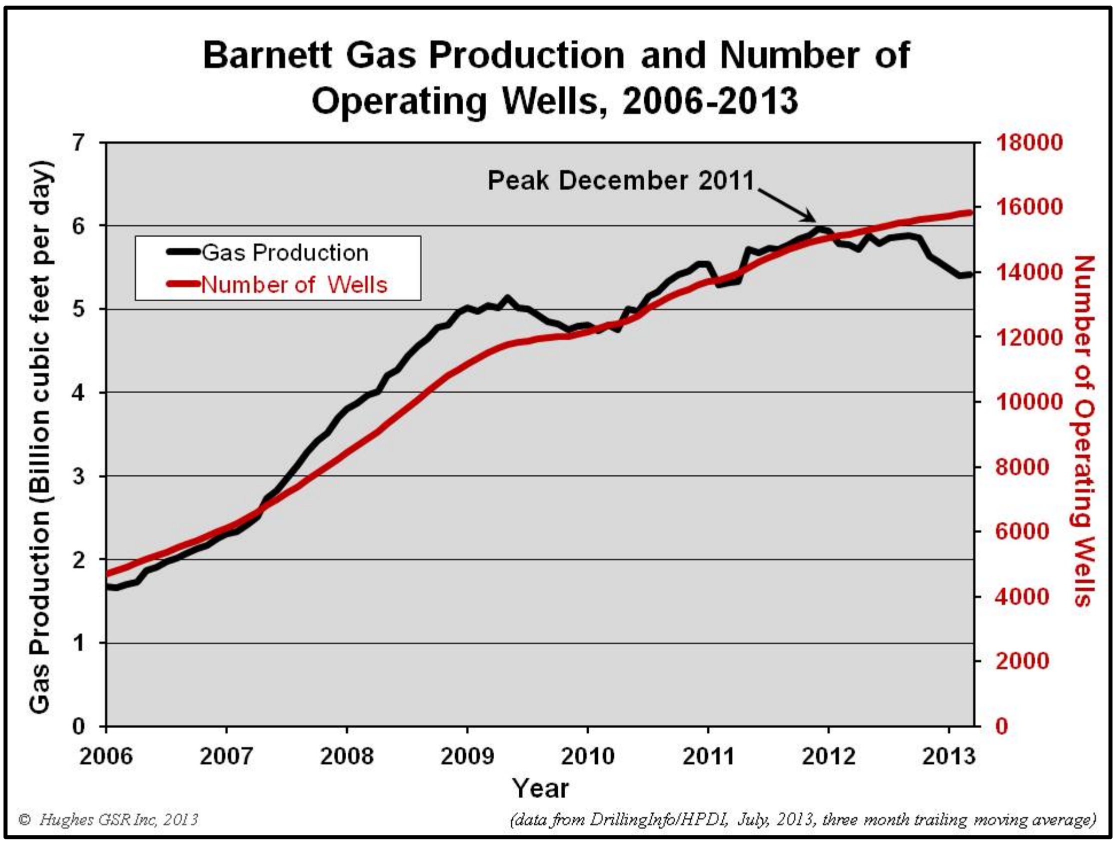
Request:

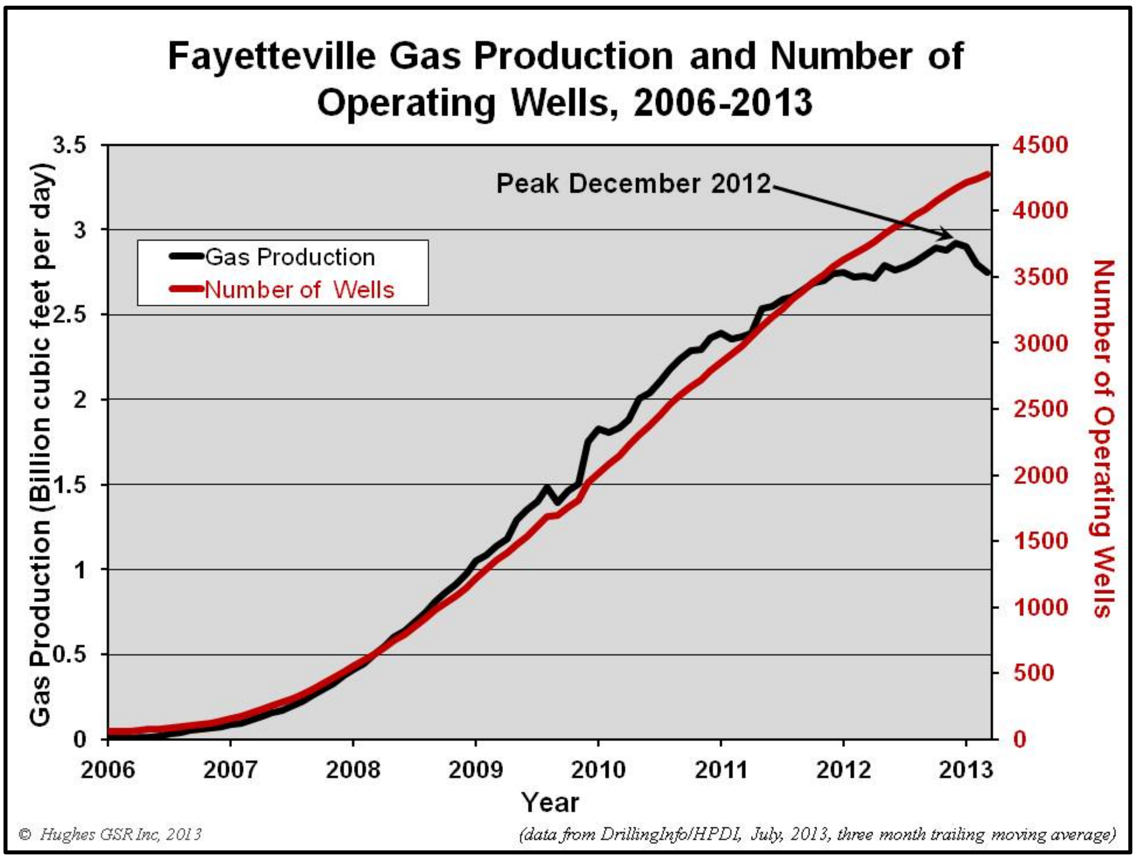
a) How did lower gas prices in 2010, 2011 and the extremely low gas prices in 2012 impact the level of production in the shale plays?

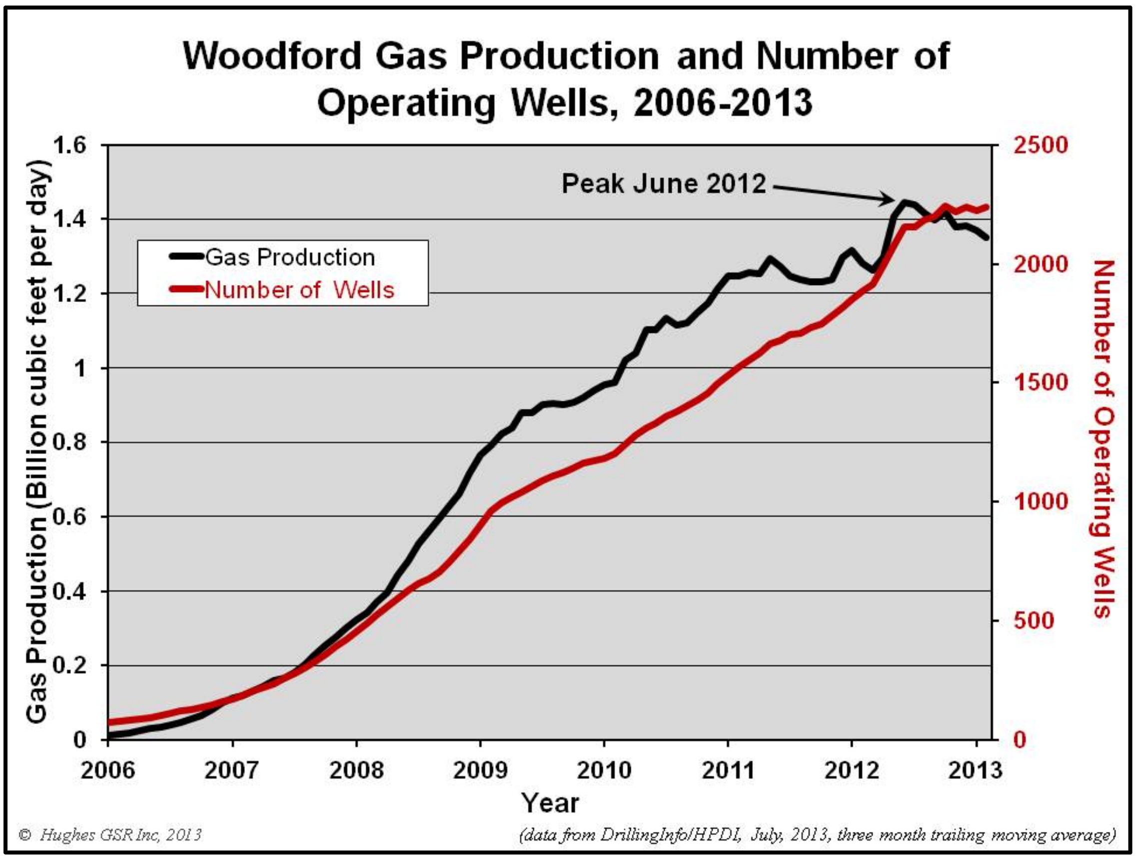
Response:

The following charts illustrate the relationship of the number of wells operating and the level of production for each of these four plays based on data from January 2006 through February-March 2013. Gas prices appear to have had little effect as in all cases the well count grew *rapidly in the 2010 to 2012 period and in all cases production peaked in the 2011 to 2012 period. All four plays appear to be past peak production. It is conceivable that considerably higher gas prices could allow enough wells to be drilled to stop production declines and even grow production but this would be a relatively short term phenomenon as these plays, even though only a few years old, are extensively drilled and, as noted above, well quality is declining as drilling moves into lower quality parts of the reservoirs – meaning that progressively larger numbers of wells will be required to offset field declines going forward.*




Barnett Gas Production and Number of Operating Wells, 2006-2013
Peak December 2011
Gas Production
Number of Wells
Gas Production (Billion cubic feet per day)
Number of Operating Wells
0
1
2
3
4
5
6
7
0
2000
4000
6000
8000
10000
12000
14000
16000
18000
2006
2007
2008
2009
2010
2011
2012
2013
Year
© Hughes GSR Inc, 2013
(data from DrillingInfo/HPDI, July, 2013, three month trailing moving average)


Fayetteville Gas Production and Number of Operating Wells, 2006-2013
Peak December 2012
Gas Production
Number of Wells
Gas Production (Billion cubic feet per day)
Number of Operating Wells
Year
3.5
3
2.5
2
1.5
1
0.5
0
4500
4000
3500
3000
2500
2000
1500
1000
500
0
2006
2007
2008
2009
2010
2011
2012
2013
© Hughes GSR Inc, 2013
(data from DrillingInfo/HPDI, July, 2013, three month trailing moving average)



Request:

a) If so, what portion of the decline was attributed to changes in gas prices?

Response:

> *That would be speculation but likely some of the drilling that was not mandatory to meet lease commitments would have been suppressed due to low prices, although as pointed out earlier drilling was strong through the 2010-2012 period. The question is how high would gas prices have to go in order to justify the drilling of enough wells to stop production decline and begin to grow production again.*

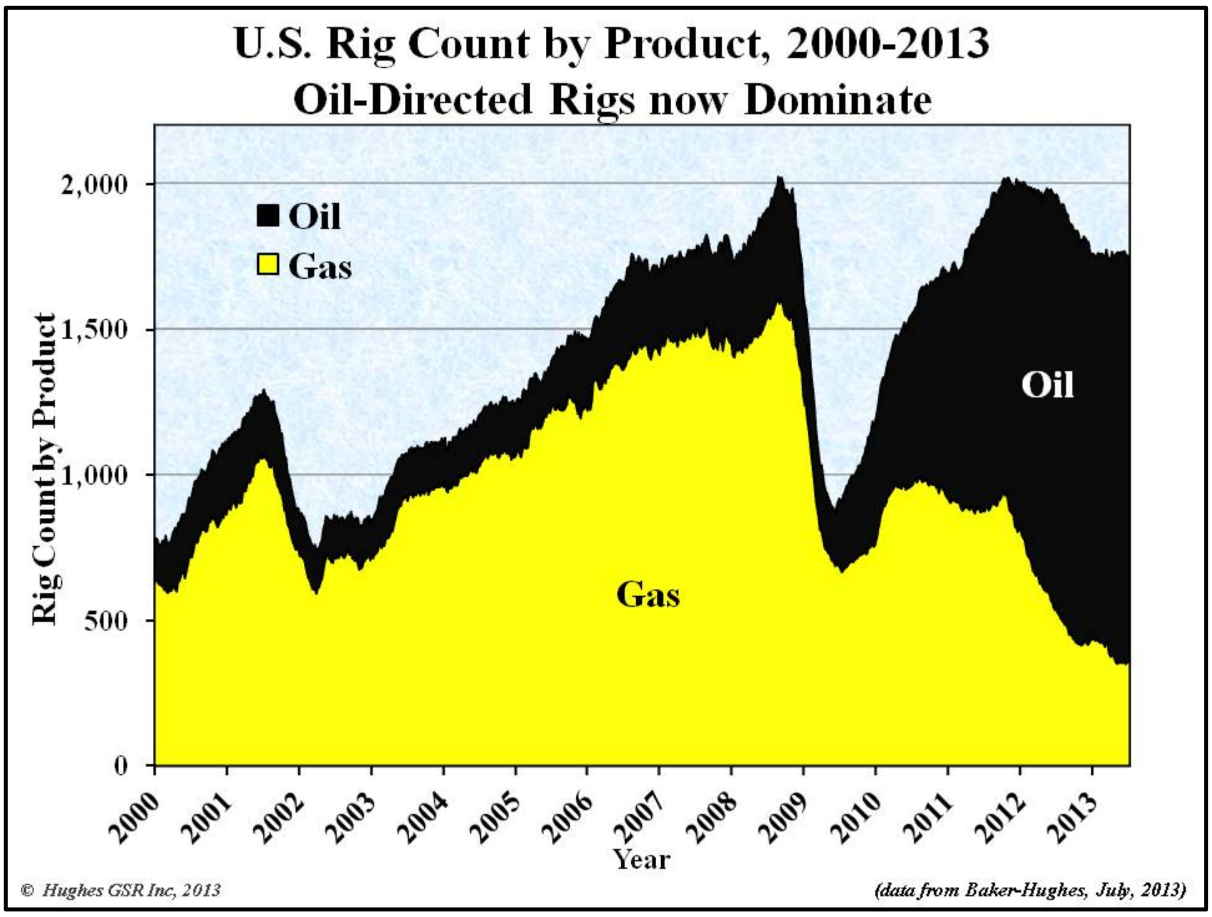
Request:

c) With the rebound in gas prices that has occurred in the first half of 2013, what will be the impact on well completion totals?

Response:

> *I do not expect the impact to be significant. One guide is provided by the most recent drilling rig counts which are provided in the chart below (current through the week of July 12, 2013). Gas*

rig counts are at an 18 year low The point being that even the rebound in gas prices has been insufficient to increase drilling and gas prices will have to be considerably higher for enough drilling to occur in these shale gas plays to maintain let alone grow production.



12. *Reference:* Exhibit L.EGD.COC.3 Page 4: "These sweet spots typically comprise 5 to 10 percent of a play's total area and are drilled first."

Request:

i) Please provide the basis for the statement.

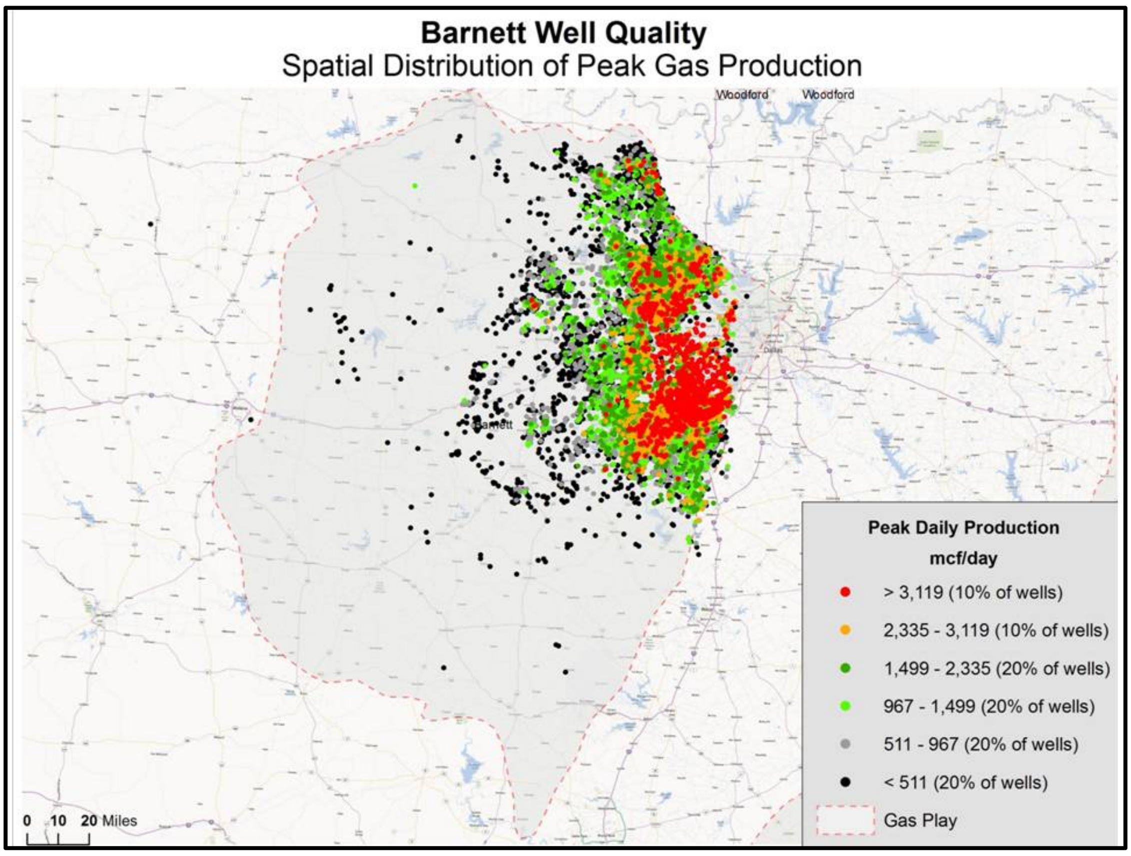
a) Please provide any and all published studies specific to shale development used to support the statement.

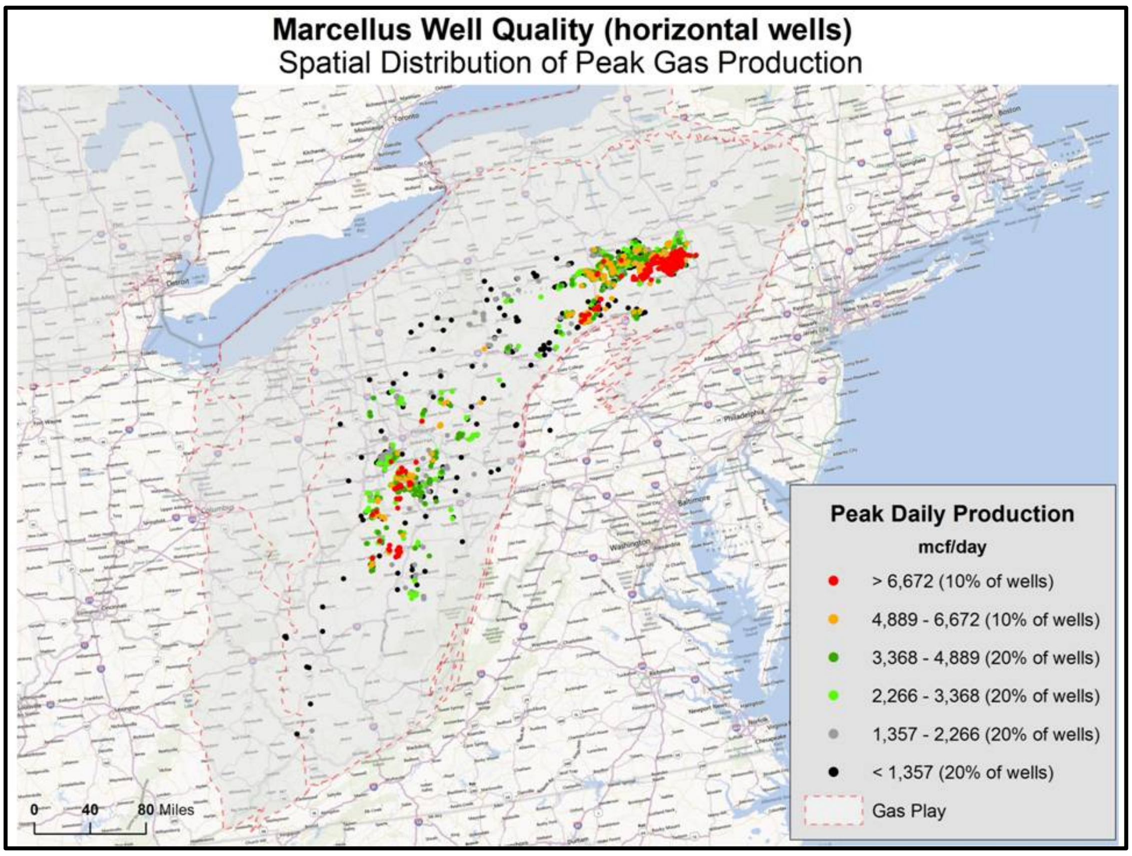
Response:

GIS maps of shale plays outlining the highest 20 percent of wells by productivity for the Haynesville, Barnett and Marcellus shale gas plays are published in http://www.postcarbon.org/reports/DBD-report-FINAL.pdf . The Energy Information

Administration has published data files delineating the extent of shale plays (in shape file format) at http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/shalegasplay.zip . These files have been integrated with drilling data current through yearend 2012 in the following maps. Well productivity is color coded on these maps which clearly illustrates that sweet spots (ie.

highest productivity wells) comprise 5-10 percent of the total play area or less. The Barnett shale (the oldest shale gas play) and the Marcellus shale are illustrated below (the EIA play area is in light gray bounded by a dashed red line on these maps).





Request:

b) To what extent is the statement based upon analysis of non-shale resource development.

Response:

This statement is based only on an analysis of shale resource development.

Request:

ii) To what extent has drilling required to hold acreage affected activity in the in the Marcellus and other shale resource areas?

a) Have wells been drilled in the Marcellus to hold acreage?

Response:

This is not uncommon practice, and is likely to have taken place in the Marcellus.

Request:

b) How many wells have been drilled in the Marcellus to hold acreage?

Response:

This is confidential business information the companies involved have no obligation to disclose.

Request:

a) What is the source of that information?

Response:

See response to UGL-COC IR 12(b)

Request:

d) Have wells been drilled to delineate the formation held by a production company?

Response:

This is not uncommon practice. Such wells are typically vertical, not horizontal. My assessment of declining well productivity only included horizontal wells.

Request:

e) How many wells have been drilled to delineate the formation held by a production company?

Response:

See Response to UGL-COC IR 12(b)

Request:

f) What is the source of that information?

Response:

See Response to UGL-COC IR 12(e)

Request:

iii) What have you assumed about the distribution of the decline in EUR per well as a function of distance from the "sweet spots"?

Response:

I have made no such assumptions. The empirical data of well productivity posted on the maps in the figures above provide a clear indication of the extent of sweet spots. As noted earlier the IP of a well is an indicator of the EUR, with the highest IPs likely to yield the highest EURs. I *provided an estimate of average EUR by county for the Marcellus in the evidence I filed (see Figure 5).*

Request:

iv) Please describe the average potential EUR per well for the Marcellus formation as a whole.

a) What is the source of the estimate?

Response:

The average EUR assumed for the Marcellus shale by the U.S. Energy Information Administration in its Annual Energy Outlook 2012 is 1.56 billion cubic feet (see page 58, Table 1 - http://www.eia.gov/forecasts/archive/aeo12/index.cfm). The U.S. Geological Survey also published EUR estimates in 2012 of 1.158 bcf for the Interior Marcellus and estimates of .129 and .208 bcf for the Western Margin and Foldbelt Marcellus, respectively http://pubs.usgs.gov/of/2012/1118/OF12-1118.pdf . So based on these estimates the average for the Marcellus as a whole would range from roughly 1 to 1.56 bcf. These estimates are lower than my calculations for the sweet spots in the Marcellus included in my evidence (see Figure 5).

Request:

v. Assuming that the current density in the Marcellus region as a whole has been 2 wells drilled per pad, what are the implications of the potential to expanded to 8 to 10 wells per pad and expanding the number of completions per well on the cost per well completion? Please explain thoroughly.

Response:

The number of wells drilled per pad is irrelevant in terms of how much of the resource can be recovered and the rate of recovery of the resource. This is a function of the spacing of well bores in the subsurface, not on the surface. Certainly drilling more wells per pad will result in fewer pads to cover the resource and likely a reduction in per well costs due to limiting the number of pads and the infrastructure required to service each pad.

13. *Reference:* Exhibit L.EGD.COC.3 Page 6: “The extent to which these sweet spots can continue to produce cheap natural gas depends on the number of available drilling locations, which are running out.”

Request:

i) Please provide the statistical basis of the assertion that the number of available drilling locations are running out.

Response:

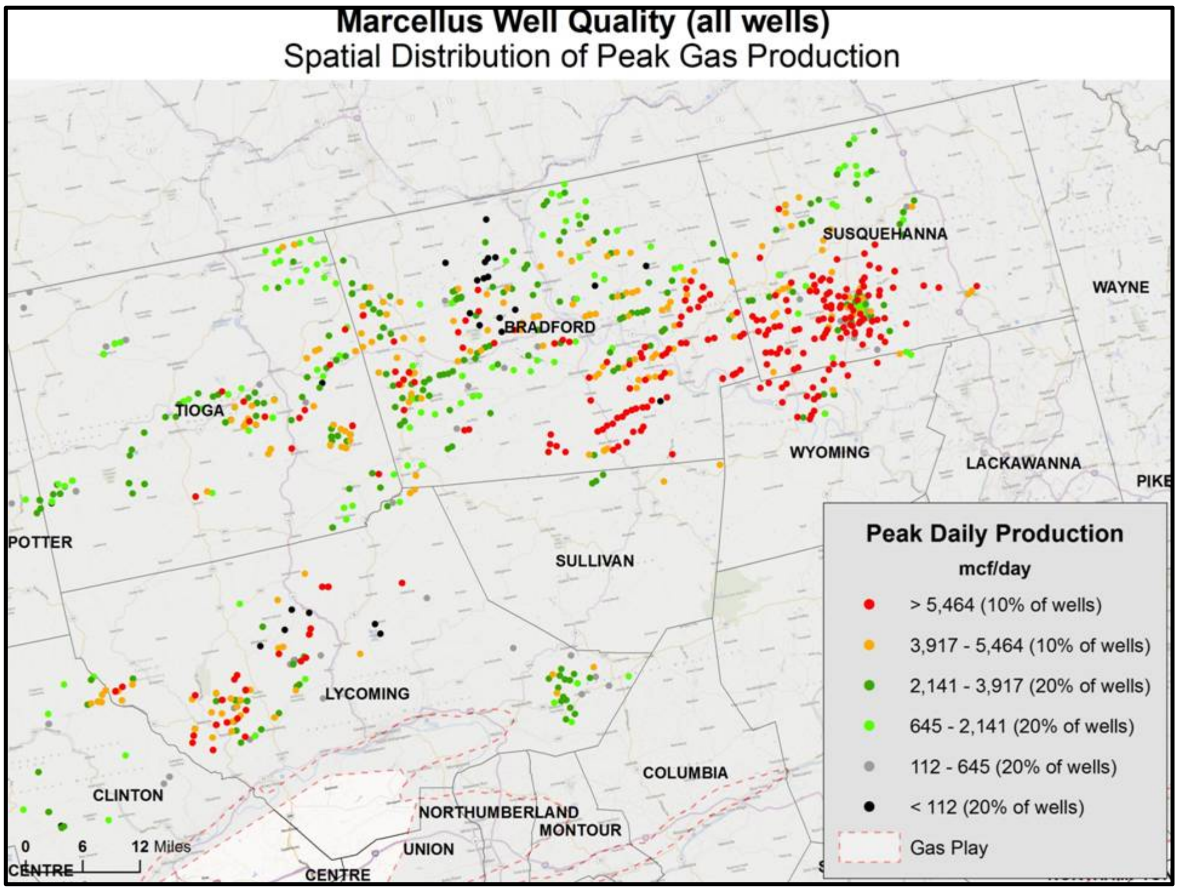
The statistical basis is provided in Figure 8 [Exhibit L.EGD. COC 3] which illustrates that average well quality as determined by IP is declining in several of the major shale plays. This indicates that drilling is moving into lower quality parts of the play and away from sweet spots, as available locations in sweet spots are used up.

Request:

a) Please provide the spatial GIS analysis of the Marcellus formation used to support the conclusion.

Response:

As noted in my evidence the Marcellus is a new shale gas play and that locations still exist in sweet spots – the statement in my evidence that available drilling locations in sweet spots are running out applied to other shale plays, not the Marcellus. This is indicated by the rising IPs over time in the figure above and in Figure 8 provided in my evidence, which suggests that locations still exist in sweet spots in the Marcellus and that better technology is still making a difference. A GIS map included below of the sweet spot in northeast Pennsylvania indicates this. The question is how many more locations are left and how long will these last at current drilling rates – as evidenced from other shale plays it is only a matter of time before the best locations are used up.



Request

b) If no spatial GIS analysis was performed, please describe the methodology used.

Response:

> *Well quality was analyzed by county. This allowed a calculation of EURs by county as illustrated in Figure 5 of my evidence. An indication of the saturation of the best locations in the most productive counties is a decline in the highest one month average well productivity in Susquehanna County from 5848 mcf/d in 2010 to 5354 mcf/d in 2012, despite the application of better technology. Bradford County has similarly declined from 3953 mcf/d in 2010 to 3739 in 2012. These are the top two producing counties. Average IPs in other counties are much lower but are rising, hence my overall assessment of the Marcellus as a young play that will keep growing in production for several years, as long as drilling rates remain above field decline rates (current drilling rates are well above those needed to offset the current field decline rate).*

Request:

c) Please provide the any and all work papers supporting the conclusion.

Response:

See Responses to UGL-COC IRs 13(i) (a) and (b)

14. *Reference:* Exhibit L.EGD.COC.3 Page 9: "If addressed by effective government measures, the cost of shale gas production is likely to greatly increase."

[As the following questions are more appropriately addressed to Ms. Sumi, she has provided the following Responses.]

Request:

i. Please provide the production cost analysis (if any), including all work papers, used to support the statement.

Response:

In many cases, the oil and gas industry has made statements that increased regulation will increase costs and decrease shale gas development. The industry, however, does not always provide cost analyses for such statements. However, in 2009 the American Petroleum Institute (API) commissioned a study examining the potential impact on future oil and gas production of proposed policy changes pertaining to hydraulic stimulation or fracturing of oil and gas wells.

They looked at:

"... the effects of regulating hydraulic fracturing on future hydrocarbon production by generating production forecasts for three policy scenarios. The results from these three scenarios are compared with production levels in a reference case, which is based on existing regulations, and with the production levels that would come from existing wells alone ("no drilling"). The results show that the effects of any policy will be substantial in the short-term and will increase in the long-term due to the increasing importance of unconventional plays in natural gas production. These effects will generally be negative, particularly for natural gas,

with the potential for higher prices, more imports and negative economic impacts from reduced domestic drilling." [1]

[1] IHS Global Insight. 2009. Measuring the Economic and Energy Impacts of Proposals to Regulate Hydraulic Fracturing. Prepared for the American Petroleum Institute. p. 2.
http://s3.amazonaws.com/propublica/assets/natural_gas/ihs_gi_hydraulic_fracturing_task1.pdf

Request:

a) What regulation other than those that have been promulgated by the U.S. EPA such as the New Source Performance Standards subpart OOOO and Oil and Gas Production NESHAPS are considered “effective government measures”?

Response:

Between 2008 and 2011, five new drilling-related regulations were passed in Pennsylvania to address a range of issues presented by shale gas drilling. They related to water withdrawals, discharge of shale gas wastewater into streams, buffers between drilling and water bodies, well casing and cementing & disclosure of fracturing chemicals, and permit fees for new wells.

While the new rules were more stringent than earlier ones, it is likely to soon determine whether or not they are "effective." In all likelihood, even seemingly strong regulations will continue to evolve as more information on impacts related to shale gas development come to light.

For example, in 2011 the Pennsylvania Department of Environmental Protection (DEP) enacted a rule to improve drilling, casing, cement, testing, monitoring and plugging requirements for oil and gas wells to minimize gas migration and protect water supplies. The requirements were estimated to add between $10,000 and $500,000 to the cost of developing a Marcellus shale well.[2]

There is evidence to suggest that the well casing requirements were not strong enough. Since the rules were promulgated in 2011, there have continued to be high rates of well failures that suggest that Marcellus shale gas wells in Pennsylvania continue to leak despite the stronger rules.[3]

Request:

b) Please provide any and all cost analysis conducted by Mr. Hughes that has been filed in a regulatory proceeding regarding the cost impacts of promulgated Bureau of Land Management (BLM).

[2] http://www.pabulletin.com/secure/data/vol41/41-6/239.html
[3] Ingraffea, A. Oct. 2012. "Fluid migration mechanisms due to faulty well design and/or construction: an overview and recent experiences in the Pennsylvania Marcellus Play." http://www.psehealthyenergy.org/data/PSE__Cement_Failure_Causes_and_Rate_Analaysis_Jan_2013_Ingraffea1.pdf

Response:

I assume that Union Gas is referring to the hydraulic fracturing rules being proposed by BLM, which according to the agency "will modernize BLM's management of hydraulic fracturing operations, and help to establish baseline environmental safeguards for these operations across all public and Indian lands. The updated draft proposal maintains the three main components of the initial proposal: requiring operators to disclose the chemicals they use in fracturing activities on public lands; improving assurances of well-bore integrity to verify that fluids used during fracturing operations are not contaminating groundwater; and confirming that oil and gas operators have a water management plan in place for handling fluids that flow back to the surface."

The BLM released its first proposed rules in May 2012. During the comment period that followed, the BLM received more than 177,000 public comments and feedback that helped to inform the updated draft proposal, which was published May 25, 2013. BLM revised its draft proposal earlier this year, and extended the public comment period on the revised rules until August 23, 2013.[4]

The rule has faced intense lobbying and pushback from industry groups who have argued that the regulations will increase their costs.[5] *BLM has estimated that the costs range from $12 million to $20 million per year. BLM explained tha in analyzing the costs and benefits of the rule, "it is important to differentiate between the activities that operators currently conduct and those additional activities that the rule would compel. This change in behavior provides the basis of the cost and benefit estimates."*[6]

Some of the provisions that remain in the revised regulations, or are being examined by BLM, that will increase costs include:

- *The BLM received some comments that certain provisions of the proposed rule were open ended, which would give BLM too much discretion and would result in uncertainty, delays, and increased costs for operators. For example, some comments suggested that the ability of the BLM to request additional information in the Sundry Notice requesting approval for hydraulic fracturing (section 3162.3-3(d)(7)) was open ended. The BLM*

[4] U.S. Bureau of Land Management. June 7, 2013. "BLM Extends Public Comment Period on Proposed Hydraulic Fracturing Rule." News Release. http://www.blm.gov/wo/st/en/info/newsroom/2013/june/nr_06_07_2013.html

[5] Geman, B. and Colman, Z. April 11, 2013. "Fracking rule is imminent," The Hill. http://thehill.com/blogs/e2-wire/e2-wire/293479-overnight-energy-fracking-rule-is-imminent-outgoing-interior-chief-says#ixzz2ZJgsjsok

[6] U.S. Bureau of Land Management. Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands. Proposed Rule. BLM-2013-0002. Docket Information. http://www.regulations.gov/#!documentDetail;D=BLM-2013-0002-0010

- *believes that the provisions in the revised proposed rule are necessary to provide the flexibility essential to regulating operations over a broad range of geologic and environmental conditions. . . The BLM did not revise the rule as a result of these comments.*
- *Some commenters objected to the cost of the requirement for an [mechanical integrity test - MIT] prior to hydraulic fracturing due primarily to the delay and the cost of rig time. . . The BLM believes that performing a successful MIT prior to starting hydraulic fracturing is essential to ensuring the casing and fracture string (if used) are capable of withstanding the pressure used and serves as an early indicator whether the applied pressures can be successfully supported. No revisions to the initial proposed rule were made as a result of this comment.*
- *The BLM received some comments stating that an MIT is not needed on every well and should only be required on wells that are more than 5 years old or if pressure exceeds 80% of casing yield. The BLM believes that the requirements in section 3162.3-3(f)(1) of the revised proposed rule are standard industry practice and are required to ensure the casing is capable of withstanding the pressures applied during hydraulic fracturing operations. No revisions to the revised proposed rule were made as a result of this comment.*
- *The BLM shares commenters' concerns about contributions of pits to air quality problems, and the possibility of failures, leaks, and overflow events. . .In view of comments raising concerns that flowback fluids present hazards to the environment beyond those that can be controlled in lined pits, the BLM is specifically requesting comments on whether the rule should require flowback fluids to be stored only in closed tanks, and not allow them to be stored in lined pits. . .Another alternative would be for the rule to specify that a lined pit must be equipped with a leak detection system, as is required for lined pits for produced water under Onshore Order No. 7. Some commenters advocated for requiring double-lined pits. The BLM asks for comments on the costs and benefits of the foregoing alternatives for storage of flowback fluids.*[7]

Question:

c) Please provide any and all cost analysis conducted by Mr. Hughes that has been filed ina regulatory proceeding regarding the cost impacts of state environmental regulation of shale gas development.

---

[7] Idem

Response:

No such analysis has been filed by either Mr. Hughes or myself.

Request:

d) Please provide citations to any and all testimony where you have examined increases in production costs driven by environmental regulation of shale gas development.

Response:

No such testimony has been given by Mr. Hughes or myself.

15. *Reference:* Exhibit L.EGD.COC.3 Page 10: "U.S. natural gas production has remained flat for the past six months, even as gas prices rose from historic lows."

Request:

i) During the period of the last six months, has Marcellus shale gas production increased?

Response:

Yes.

Request:

ii) During the past six months, has production from traditional gas resource formations (Non-shale and tight formations) in the United States and Canada decreased?

Response:

Production data from the Energy Information Administration and the National Energy Board do not differentiate production by play type so it is not possible from those sources to definitely say whether production from traditional gas formations has declined, remained flat, or increased. As noted in my evidence, the Energy Information Administration was the source of data used in my evidence.

Request

iii) During the past six months, have increases in shale gas production offset the declines in traditional gas resource formations (Non-shale and tight formations) in the United States and Canada?

Response:

As pointed out in Figure 9 of the evidence I submitted U.S. gas production has been flat for the past six months (September 2012 to February 2013). Growth in the Marcellus has offset declines in other major shale gas plays as illustrated in Figure 10 of my evidence resulting in an aggregate plateau in production from these shale gas plays. The monthly gas production data from the U.S. Energy Information Administration is not disaggregated by play type, nor is the monthly gas production data for Canada provided by the National Energy Board, so it is not possible to definitively say one way or another if traditional gas resource formations are declining in production or rising or staying flat. It does appear, however, that shale gas production is at least flat due to growth in production from the Marcellus.

Request:

iv) Does drilling activity increase instantaneously with increases in gas prices or is there a lag in the drilling response? a) Assuming that there is a lag in the drilling response, typically how long is the lag (expressed in months)?

Response:

It is likely that there would be a lag, however, as pointed out in the above chart of rig counts provided in answer to Question 11, the current uptick in price to the $4/MMbtu range has not been sufficient to increase gas rig counts, which are at 18 year lows. This suggests that prices required to stimulate drilling will have to be considerably higher. Without higher gas rig counts U.S. gas production will begin to fall, as the steep well- and field-declines associated with shale gas demand continuous high levels of drilling to maintain production.

Request:

v) How has the production of associated gas that is being developed with natural gas liquids and shale oil affected gas production over the last six months?

Response:

The production of associated gas has helped maintain U.S. gas production. The two most important fields for associated gas, the Bakken and Eagle Ford, contributed .71 bcf/d and 2.72 bcf/d, respectively, as of December 2012. While this is important, it only represents 5.2 percent of December 2012 U.S. production of 65.9 bcf/d. In other fields so-called "wet" gas has helped bolster the economics of shale gas wells, however the price of natural gas liquids has also been reduced recently due to a glut, which has limited this economic effect.