Subject	Lebanon city, New Hampshire				
	Occupied housing units		Owner-occupied housing units		Renter-occupied housing units
	Estimate	Margin of Error	Estimate	Margin of Error	Estimate
Occupied housing units	6,391	+/-281	3,190	+/-346	3,201
UNITS IN STRUCTURE					
1, detached	42.8%	+/-4.1	75.5%	+/-5.9	10.2%
1, attached	4.5%	+/-1.6	3.3%	+/-1.9	5.7%
2 apartments	7.0%	+/-2.6	1.9%	+/-1.2	12.0%
3 or 4 apartments	11.8%	+/-2.8	4.6%	+/-2.6	19.0%
5 to 9 apartments	8.8%	+/-2.5	3.5%	+/-3.0	14.1%
10 or more apartments	22.1%	+/-3.1	6.3%	+/-3.7	37.9%
Mobile home or other type of housing	3.0%	+/-1.5	4.9%	+/-3.0	1.1%
YEAR STRUCTURE BUILT					
2014 or later	0.0%	+/-0.4	0.0%	+/-0.9	0.0%
2010 to 2013	4.2%	+/-1.7	0.8%	+/-0.9	7.6%
2000 to 2009	10.9%	+/-2.6	10.0%	+/-3.0	11.7%
1980 to 1999	24.9%	+/-4.0	25.7%	+/-5.4	24.2%
1960 to 1979	24.9%	+/-3.8	28.1%	+/-5.7	21.8%
1940 to 1959	6.6%	+/-2.7	7.6%	+/-3.5	5.6%
1939 or earlier	28.5%	+/-4.3	27.8%	+/-5.5	29.1%
ROOMS					
1 room	1.0%	+/-0.9	0.0%	+/-0.9	2.0%
2 or 3 rooms	21.4%	+/-3.4	6.3%	+/-3.6	36.4%
4 or 5 rooms	40.4%	+/-4.5	30.0%	+/-6.5	50.8%
6 or 7 rooms	18.4%	+/-3.4	31.3%	+/-6.5	5.6%
8 or more rooms	18.8%	+/-3.8	32.4%	+/-6.1	5.2%
BEDROOMS					
No bedroom	1.3%	+/-0.9	0.0%	+/-0.9	2.6%
1 bedroom	16.9%	+/-3.6	5.6%	+/-3.1	28.1%
2 or 3 bedrooms	68.0%	+/-4.2	70.3%	+/-5.6	65.7%

Subject	Lebanon city, New Hampshire				
	Occupied housing units		Owner-occupied housing units		Renter-occupied housing units
	Estimate	Margin of Error	Estimate	Margin of Error	Estimate
4 or more bedrooms	13.8%	+/-2.9	24.0%	+/-5.2	3.6%
COMPLETE FACILITIES					
With complete plumbing facilities	100.0%	+/-0.4	100.0%	+/-0.9	100.0%
With complete kitchen facilities	99.5%	+/-0.7	99.1%	+/-1.3	100.0%
VEHICLES AVAILABLE					
No vehicle available	7.9%	+/-2.6	2.4%	+/-1.8	13.3%
1 vehicle available	49.3%	+/-3.6	35.4%	+/-6.0	63.3%
2 vehicles available	32.1%	+/-3.3	44.2%	+/-5.4	20.1%
3 or more vehicles available	10.7%	+/-2.7	18.1%	+/-4.6	3.3%
TELEPHONE SERVICE AVAILABLE					
With telephone service	97.4%	+/-1.4	98.5%	+/-1.3	96.3%
HOUSE HEATING FUEL					
Utility gas	4.9%	+/-1.7	4.0%	+/-2.1	5.7%
Bottled, tank, or LP gas	22.3%	+/-3.6	19.1%	+/-5.0	25.5%
Electricity	17.2%	+/-3.3	5.7%	+/-3.6	28.6%
Fuel oil, kerosene, etc.	48.5%	+/-4.6	59.6%	+/-6.8	37.5%
Coal or coke	0.4%	+/-0.6	0.8%	+/-1.1	0.0%
All other fuels	6.5%	+/-2.4	10.4%	+/-3.7	2.7%
No fuel used	0.2%	+/-0.3	0.4%	+/-0.7	0.0%

Data available at: https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=CF

R-6 Chaffee																
CC per month	Number of months	Total CC		Yearly ADTH	50	Yearly therms used	500						Existing Rates as of 2/17			
						Based on 80/20 split						Winter 1st 100 therm rate	$ 0.4544			
$ 28.73	12	$ 344.76										Winter over 100 therm rate	$ 0.3760			
												Summer 1st 20 therm rate	$ 0.4544			
												Summer over 20 therm rate	$ 0.3760			
Month	Actual Therms Used	1st 100 therms winter	over 100 therms winter	1st 20 therms summer	over 20 therms summer	Monthly Total Distribution	LDAC	LDAC Total	COG	COG Total	Gas Bill					
Aug-16	6			$ 2.50	$ -	$ 2.50	$ 0.1014	$ 0.56	$ 0.4200	$ 2.31	$ 34.10					
Sep-16	6			$ 2.50	$ -	$ 2.50	$ 0.1014	$ 0.56	$ 0.4200	$ 2.31	$ 34.10					
Oct-16	25			$ 9.09	$ 1.88	$ 10.97	$ 0.1014	$ 2.54	$ 0.4890	$ 12.23	$ 54.46					
Nov-16	65	$ 29.54	$ -			$ 29.54	$ 0.0553	$ 3.59	$ 0.6439	$ 41.85	$ 103.71					
Dec-16	81	$ 36.58	$ -			$ 36.58	$ 0.0553	$ 4.45	$ 0.6439	$ 51.83	$ 121.59		$ 0.36	$ 1.15		
Jan-17	105	$ 45.44	$ 1.88			$ 47.32	$ 0.0640	$ 6.72	$ 0.7276	$ 76.40	$ 159.17		$ 3.57	$ 11.54		
Feb-17	87	$ 39.53	$ -			$ 39.53	$ 0.0640	$ 5.57	$ 0.6012	$ 52.30	$ 126.14		$ 13.11	$ 1.65		
Mar-16	58	$ 26.36	$ -			$ 26.36	$ 0.1014	$ 5.88	$ 0.2634	$ 15.28	$ 76.24		$ 16.68	$ 13.19		
Apr-16	43	$ 19.31	$ -			$ 19.31	$ 0.1014	$ 4.31	$ 0.4423	$ 18.80	$ 71.15					
May-16	15			$ 6.82	$ -	$ 6.82	$ 0.1014	$ 1.52	$ 0.4117	$ 6.18	$ 43.24					
Jun-16	6			$ 2.50	$ -	$ 2.50	$ 0.1014	$ 0.56	$ 0.4400	$ 2.42	$ 34.21					
Jul-16	6			$ 2.50	$ -	$ 2.50	$ 0.1014	$ 0.56	$ 0.4400	$ 2.42	$ 34.21					
Yearly Distribution Total	500					$ 226.42		$ 36.81		$ 284.33	$ 892.31					
								Rolling 12 month average CGA	$ 0.4953		Equivalent Gallons	NHOEP Price	Yearly Total	Savings vs Current Rates	Savings percent	
Existing Customer Yearly Total	$ 892.31					Customer GPM	$ 571			Oil	362	$ 2.32	$ 839.36	-$52.95	-6%	
										Propane	549	$ 2.97	$ 1,630.08	$ 737.76	45%	
Average Price per therm	$ 1.78															
Oil Equivalent	$ 2.46															

TICKET NUMBER 848
SUBURBAN PROPANE COMPANY
DATE 04/29/16
START COUNT 0.0 GALLONS
END GROSS COUNT 54.0 GALLONS
GROSS DELIVERY 54.0 GALLONS
2 2
SALE NUMBER 760
METER NUMBER 175218
UNIT ID 175218

INVOICE NO	QUANTITY	DESCRIPTION	AMOUNT
2311-737088	54.0 gallons	FUEL OIL @$2.0141/GALLON	$108.76
		STATE UST & CLEANUP FEES $0.01375	0.74
		INVOICE SUBTOTAL	$109.50
		PLEASE PAY THIS AMOUNT	$109.50

Dyed Heating Oil: Not for use in highway or non-road locomotive or marine engines

SUBURBAN PROPANE-2311
PO# ______________
Name: JONATHAN CHAFFEE
ACCT.#: 2311-125329-002 Driver ID
Tank Serial #: 204

*If Safety P&T is noted above see "Fees" on reverse for a description of this Safety & Training Practices Fee

For Inquiries, please call 800-776-7263 or your local office 603-448-4708

RECEIVED BY:

Customer: Please see reverse side for safety information
Item# 1528421 OPR 5208 1108

R-6 Chaffee With Fuel Club Oil

CC per month	Number of months	Total CC		Yearly ADTH	50	Yearly therms used	500						Existing Rates as of 2/17		
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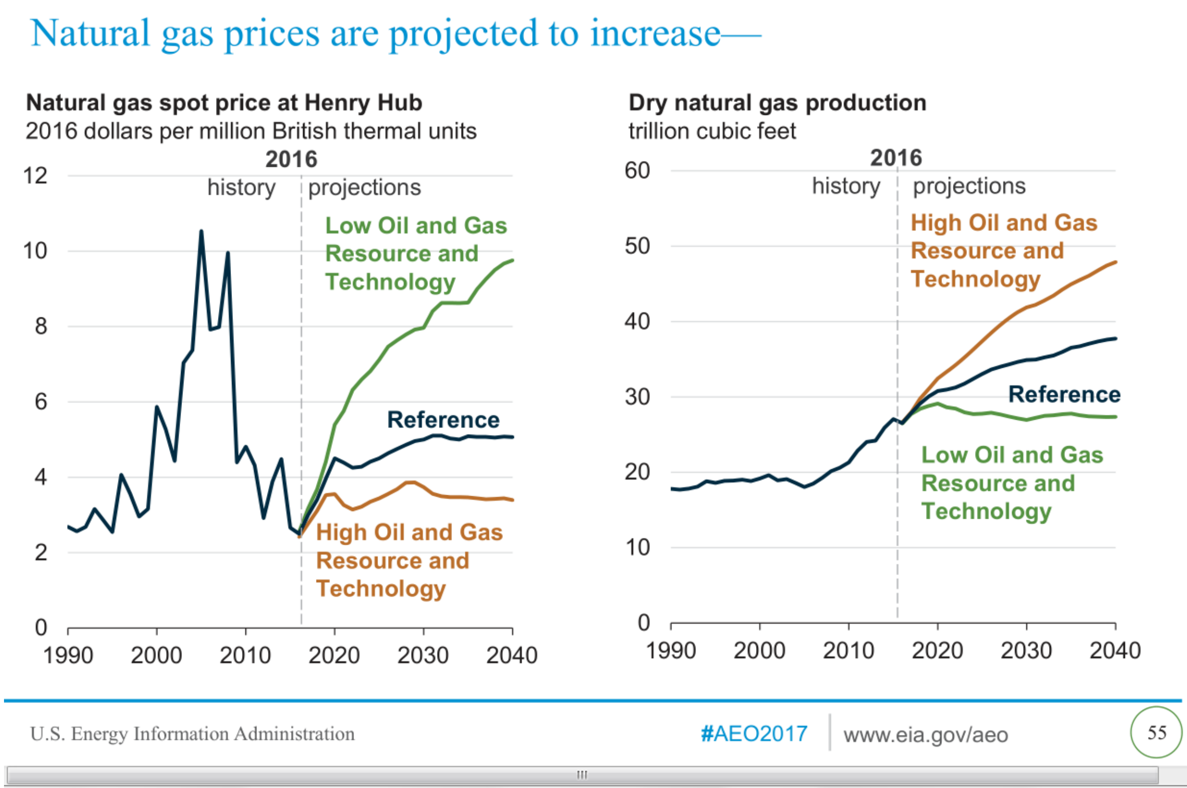


Page 55 of the U.S. Energy Information Administration report titled “Annual Energy Outlook 2017 with projections to 2050 (AE02017)

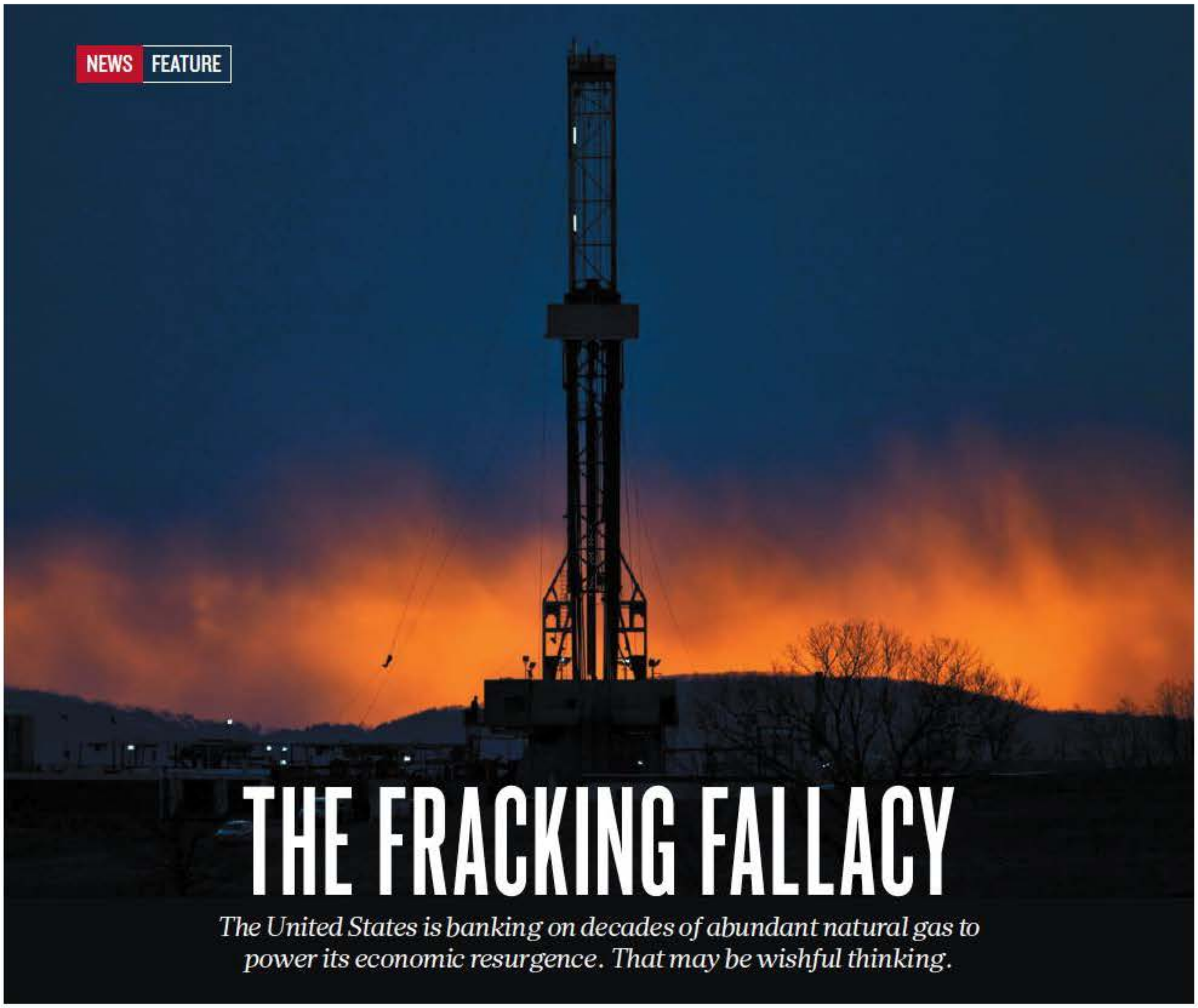
What is the Reference case?

- The ***Reference*** case projection assumes trend improvement in known technologies, along with a view of economic and demographic trends reflecting the current central views of leading economic forecasters and demographers.
- It generally assumes that current laws and regulations affecting the energy sector, including sunset dates for laws that have them, are unchanged throughout the projection period.
- The potential impacts of proposed legislation, regulations, or standards are not reflected in the Reference case.
- EIA addresses the uncertainty inherent in energy projections by developing side cases with different
- assumptions of macroeconomic growth, world oil prices, technological progress, and energy policies.
- Projections in the AEO should be interpreted with a clear understanding of the assumptions that inform them and the limitations inherent in any modeling effort.

What are the side cases?

- In the ***High Oil and Gas Resource and Technology*** case, lower costs and higher resource availability than in the Reference case allow for higher production at lower prices. In the **Low Oil and Gas Resource and Technology** case, more pessimistic assumptions about resources and costs are applied.
- The effects of economic assumptions on energy consumption are addressed in the High and Low Economic Growth cases, which assume compound annual growth rates for U.S. gross domestic product of 2.6% and 1.6%, respectively, from 2016-40, compared with 2.2% annual growth in the Reference case.

Source: U.S. Energy Information Administration #AEO2017 pages 4 and 5.



NEWS FEATURE

THE FRACKING FALLACY

The United States is banking on decades of abundant natural gas to power its economic resurgence. That may be wishful thinking.

BY MASON INMAN

When US President Barack Obama talks about the future, he foresees a thriving US economy fuelled to a large degree by vast amounts of natural gas pouring from domestic wells. "We have a supply of natural gas that can last America nearly 100 years," he declared in his 2012 State of the Union address.

Obama's statement reflects an optimism that has permeated the United States. It is all thanks to fracking — or hydraulic fracturing — which has made it possible to coax natural gas at a relatively low price out of the fine-grained rock known as shale. Around the country, terms such as 'shale revolution' and 'energy abundance' echo through corporate boardrooms.

Companies are betting big on forecasts of cheap, plentiful natural gas. Over the next 20 years, US industry and electricity producers are expected to invest hundreds of billions of dollars in new plants that rely on natural gas. And billions more dollars are pouring into the construction of export facilities that will enable the United States to ship liquefied natural gas to Europe, Asia and South America.

All of those investments are based on the expectation that US gas production will climb for decades, in line with the official forecasts by the US Energy Information Administration (EIA). As agency director Adam Sieminski put it last year: "For natural gas, the EIA has no doubt at all that production can continue to grow all the way out to 2040."

But a careful examination of the assumptions behind such bullish forecasts suggests that they may be overly optimistic, in part because the government's predictions rely on coarse-grained studies of major shale formations, or plays. Now, researchers are analysing those formations in much greater detail and are issuing more-conservative forecasts. They calculate that such formations have relatively small 'sweet spots' where it will be profitable to extract gas.

The results are "bad news", says Tad Patzek, head of the University of Texas at Austin's department of petroleum and geosystems engineering, and a member of the team that is conducting the in-depth analyses. With companies trying to extract shale gas as fast as possible and export significant quantities, he argues, "we're setting ourselves up for a major fiasco".

That could have repercussions well beyond the United States. If US natural-gas production falls, plans to export large amounts overseas could fizzle. And nations hoping to tap their own shale formations may reconsider. "If it begins to look as if it's going to end in tears in the United States, that would certainly have an impact on the enthusiasm in different parts of the world," says economist Paul Stevens of Chatham House, a London-based think tank.

The idea that natural gas will be abundant

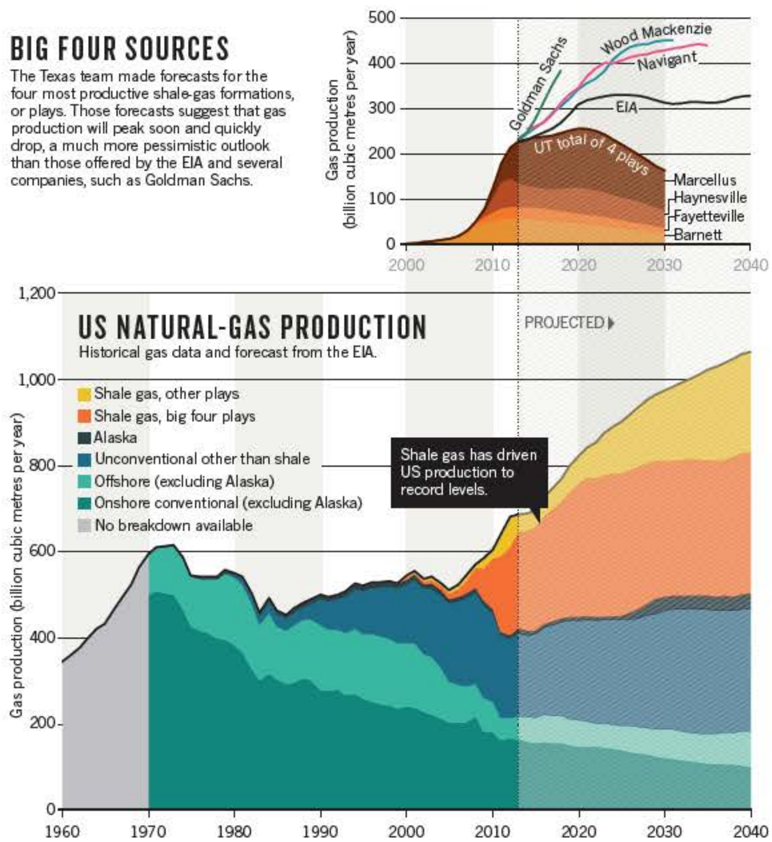
A rig drills for natural gas using hydraulic-fracturing methods in a Pennsylvania shale formation.

JIM LO SCALZO/EPA/ALAMY

ATTACHMENT Jonathan Chaffee DG 16-852
Direct Testimony of Jonathan Chaffee, July 17, 2017

BATTLE OF THE FORECASTS

Production of natural gas in the United States is climbing rapidly, and the US Energy Information Administration (EIA) predicts long-term growth. But studies by the University of Texas (UT) challenge that forecast.



SOURCE: EIA/UNIV. TEXAS/GOLDMAN SACHS/WOOD MACKENZIE/NAVIGANT

is a sharp turnaround from more pessimistic outlooks that prevailed until about five years ago. Throughout the 1990s, US natural-gas production had been stuck on a plateau. With gas supplying one-quarter of US energy, there were widespread worries that supplies would shrink and the nation would become dependent on imports. The EIA, which collects energy data and provides a long-term outlook for US energy, projected as recently as 2008 that US natural-gas production would remain fairly flat for the following couple of decades.

Then the shale boom caught everyone by surprise. It relied on fracking technology that had been around for decades — but when gas prices were low, the technology was considered too costly to use on shale. In the 2000s, however, prices rose high enough to prompt more companies to frack shale formations. Combined with new techniques for drilling long horizontal wells, this pushed US natural-gas production to an all-time high, allowing the nation to regain a title it had previously held for decades: the world's top natural-gas producer.

RICH ROCKS

Much of the credit for that goes to the Marcellus shale formation, which stretches across West Virginia, Pennsylvania and New York. Beneath thickly forested rolling hills, companies have sunk more than 8,000 wells over several years, and are adding about 100 more every month. Each well extends down for about 2 kilometres before veering sideways and snaking for more than a kilometre through the shale. The Marcellus now supplies 385 million cubic metres of gas per day, more than enough to supply half of the gas currently burned in US power plants.

A substantial portion of the rest of the US gas supply comes from three other shale plays — the Barnett in Texas, the Fayetteville in Arkansas and the Haynesville, which straddles the Louisiana–Texas border. Together, these 'big four' plays boast more than 30,000 wells and are responsible for two-thirds of current US shale-gas production.

The EIA — like nearly all other forecasters — did not see the boom coming, and has consistently underestimated how much gas would come from shale. But as the boom unfolded, the agency substantially raised its long-term expectations for shale gas. In its *Annual Energy Outlook 2014*, the 'reference case' scenario — based on the expectation that natural-gas prices will gradually rise, but remain relatively low — shows US production growing until 2040, driven by large increases in shale gas.

The EIA has not published its projections for individual shale-gas plays, but has released them to *Nature*. In the latest reference-case forecast, production from the big four plays would continue rising quickly until 2020, then plateau for at least 20 years. Other shale-gas plays would keep the boom going until 2040 (see 'Battle of the forecasts').

Petroleum-industry analysts create their own shale-gas forecasts, which generally fall in the neighbourhood of the EIA assessment. "EIA's outlook is pretty close to the consensus," says economist Guy Caruso of the Center for Strategic and International Studies in Washington DC, who is a former director of the agency. However, these consultancies rarely release the details behind their forecasts. That makes it difficult to assess and discuss their assumptions and methods, argues Ruud Weijermars, a geoscientist at Texas A&M University in College Station. Industry and consultancy studies are "entirely different from the peer-reviewed domain", he says.

To provide rigorous and transparent forecasts of shale-gas production, a team of a dozen geoscientists, petroleum engineers and economists at the University of Texas at Austin has spent more than three years on a systematic set of studies of the major shale plays. The research was funded by a US$1.5-million grant from the Alfred P. Sloan Foundation in New York City, and has been appearing gradually in academic journals[1–5] and conference presentations. That work is the "most authoritative" in this area so far, says Weijermars.

If natural-gas prices were to follow the scenario that the EIA used in its 2014 annual report, the Texas team forecasts that production from the big four plays would peak in 2020, and decline from then on. By 2030, these plays would be producing only about half as much as in the EIA's reference case. Even the agency's most conservative scenarios seem to be higher than the Texas team's forecasts. "Obviously they do not agree very well with the EIA results," says Patzek.

The main difference between the Texas and EIA forecasts may come down to how fine-grained each assessment is. The EIA breaks up each shale play by county, calculating an average well productivity for that area. But counties often cover more than 1,000 square kilometres, large enough to hold thousands of horizontal fracked wells. The Texas team, by contrast, splits each play into blocks of one square mile

(2.6 square kilometres) — a resolution at least 20 times finer than the EIA's.

Resolution matters because each play has sweet spots that yield a lot of gas, and large areas where wells are less productive. Companies try to target the sweet spots first, so wells drilled in the future may be less productive than current ones. The EIA's model so far has assumed that future wells will be at least as productive as past wells in the same county. But this approach, Patzek argues, "leads to results that are way too optimistic".

The high resolution of the Texas studies allows their model to distinguish the sweet spots from the marginal areas. As a result, says study co-leader Scott Tinker, a geoscientist at the University of Texas at Austin, "we've been able to say, better than in the past, what a future well would look like".

The Texas and EIA studies also differ in how they estimate the total number of wells that could be economically drilled in each play. The EIA does not explicitly state that number, but its analysis seems to require more wells than the Texas assessment, which excludes areas where drilling would be difficult, such as under lakes or major cities. These features of the model were chosen to "mimic reality", Tinker says, and were based on team members' long experience in the petroleum industry.

ALTERNATIVE FUTURES

The lower forecasts from Texas mesh with a few independent studies that use simpler methods. Studies by Weijermars[6], as well as Mark Kaiser[7] of Louisiana State University in Baton Rouge and retired Geological Survey of Canada geologist David Hughes[8], suggest that increasing production, as in the EIA's forecasts, would require a significant and sustained increase in drilling over the next 25 years, which may not be profitable.

Some industry insiders are impressed by the Texas assessment. Richard Nehring, an oil and gas analyst at Nehring Associates in Colorado Springs, Colorado, which operates a widely used database of oil and gas fields, says the team's approach is "how unconventional resource assessments should be done".

Patzek says that the EIA's method amounts to "educated guesswork". But he and others are reluctant to come down too hard. The EIA is doing "the best with the resources they have and the timelines they have", says Patzek. Its 2014 budget — which covers data collection and forecasting for all types of energy — totalled just $117 million, about the cost of drilling a dozen wells in the Haynesville shale. The EIA is "good value for the money", says Caruso. "I always felt we were underfunded. The EIA was being asked to do more and more, with less and less."

Patzek acknowledges that forecasts of shale plays "are very, very difficult and uncertain", in part because the technologies and approaches to drilling are rapidly evolving. In newer plays, companies are still working out the best spots to drill. And it is still unclear how tightly wells can be packed before they significantly interfere with each other.

Representatives of the EIA defend the agency's assessments and argue that they should not be compared with the Texas studies

"WE'RE SETTING OURSELVES UP FOR A MAJOR FIASCO."

because they use different assumptions and include many scenarios. "Both modelling efforts are valuable, and in many respects feed each other," says John Staub, leader of the EIA's team on oil and gas exploration and production analysis. "In fact, EIA has incorporated insights from the University of Texas team," he says.

Yet in a working paper[9] published online on 14 October, two EIA analysts acknowledge problems with the agency's methods so far. They argue that it would be better to draw upon high-resolution geological maps, and they point to those generated by the Texas team as an example of how such models could improve forecasts by delineating sweet spots. The paper carries a disclaimer that the authors' views are not necessarily those of the EIA — but the agency does plan to use a new approach along these lines when it assesses the Marcellus play for its 2015 annual report. (When *Nature* asked the authors of that paper for an on-the-record interview, they referred questions to Staub.)

BOOM OR BUST

Members of the Texas team are still debating the implications of their own study. Tinker is relatively sanguine, arguing that the team's estimates are "conservative", so actual production could turn out to be higher. The big four shale-gas plays, he says, will yield "a pretty robust contribution of natural gas to the country for the next few decades. It's bought quite a bit of time."

Patzek argues that actual production could come out lower than the team's forecasts. He talks about it hitting a peak in the next decade or so — and after that, "there's going to be a pretty fast decline on the other side", he says. "That's when there's going to be a rude awakening for the United States." He expects that gas prices will rise steeply, and that the nation may end up building more gas-powered industrial plants and vehicles than it will be able to afford to run. "The bottom line is, no matter what happens and how it unfolds," he says, "it cannot be good for the US economy."

If forecasting is difficult for the United States, which can draw on data for tens of thousands of shale-gas wells, the uncertainty is much larger in countries with fewer wells. The EIA has commissioned estimates of world shale potential from Advanced Resources International (ARI), a consultancy in Washington DC, which concluded in 2013 that shale formations worldwide are likely to hold a total of 220 trillion cubic metres of recoverable natural gas[10]. At current consumption rates — with natural gas supplying one-quarter of global energy — that would provide a 65-year supply. However, the ARI report does not state a range of uncertainty on its estimates, nor how much gas might be economical to extract.

Such figures are "extremely dubious", argues Stevens. "It's sort of people wetting fingers and waving them in the air." He cites ARI's assessments of Poland, which is estimated to have the largest shale-gas resources in Europe. Between 2011 and 2013, the ARI reduced its estimate for Poland's most promising areas by one-third, saying that some test wells had yielded less than anticipated. Meanwhile, the Polish Geological Institute did its own study[11], calculating that the same regions held less than one-tenth of the gas in ARI's initial estimate.

If gas supplies in the United States dry up faster than expected — or environmental opposition grows stronger — countries such as Poland will be less likely to have their own shale booms, say experts.

For the moment, however, optimism about shale gas reigns — especially in the United States. And that is what worries some energy experts. "There is a huge amount of uncertainty," says Nehring. "The problem is, people say, 'Just give me a number'. Single numbers, even if they're wrong, are a lot more comforting." ■

Mason Inman *is a freelance writer in Oakland, California.*

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Why Cheap Natural Gas Is History

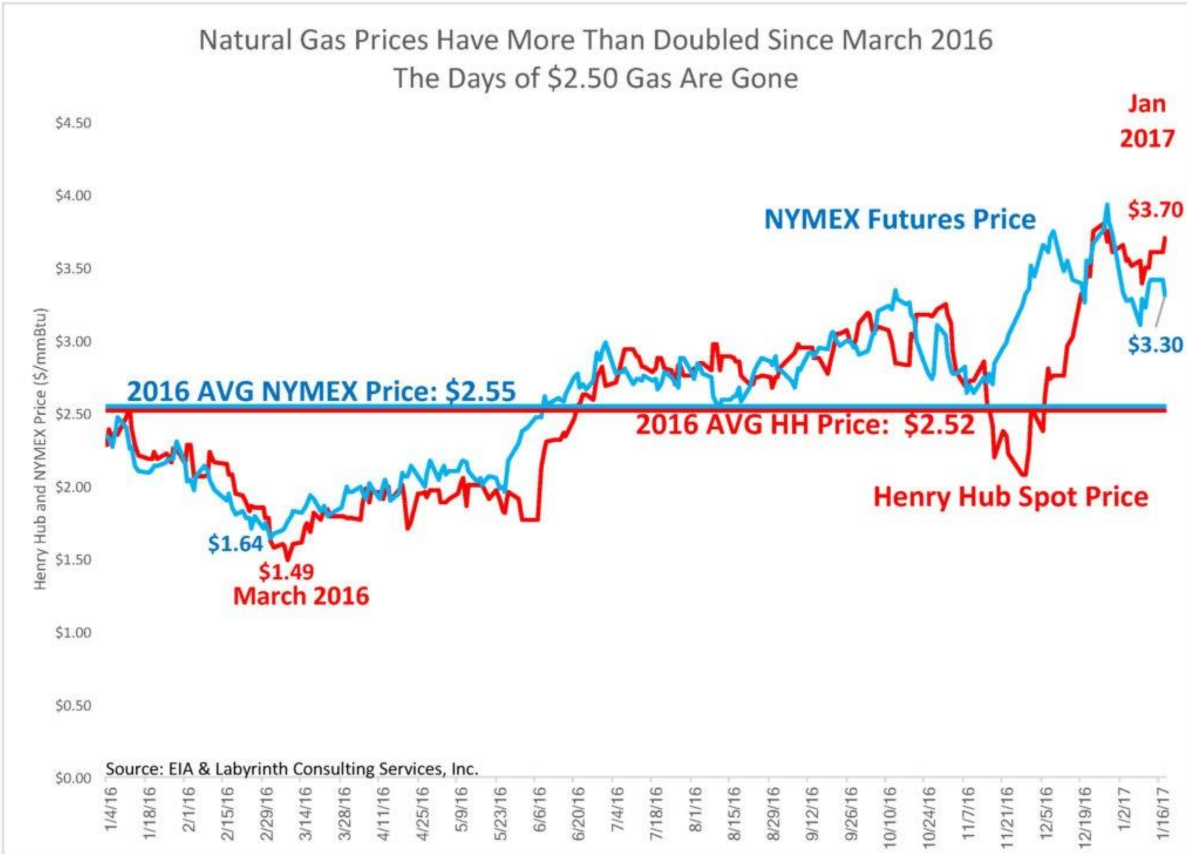
By Arthur Berman - Jan 23, 2017, 6:00 PM CST

Natural gas prices averaged a little more than $2.50 per mmBtu (million British Thermal Units) in 2016. Those days are over. Prices will average at least $3.50 to $4.00 in 2017.

Prices have more than doubled since March 2016 but gas is still under-valued. Supply is tight because demand and exports have grown and shale gas production has declined.

In April of last year, I wrote that natural gas prices should double and they did. Henry Hub spot prices increased 2 1/2 times from $1.49 to $3.70 per mmBtu and NYMEX futures prices doubled from $1.64 to $3.30 per (Figure 1).

http://oilprice.com/images/tinymce/Berman2301A.jpg



(Click to enlarge)

Figure 1. Natural Gas Prices Have More Than Doubled Since March 2016: The Days of $2.50 Gas Are Gone. Source: EIA and Labyrinth Consulting Services, Inc.

Nevertheless, gas prices are still too low. Storage was at record high levels throughout 2016 reaching 4.1 Bcf (billion cubic feet) and 84% of working capacity in mid-December. Storage has fallen 1.1 Bcf in the last month to 61% of capacity. That is below the 5-year average (pink, dashed line in Figure 2).

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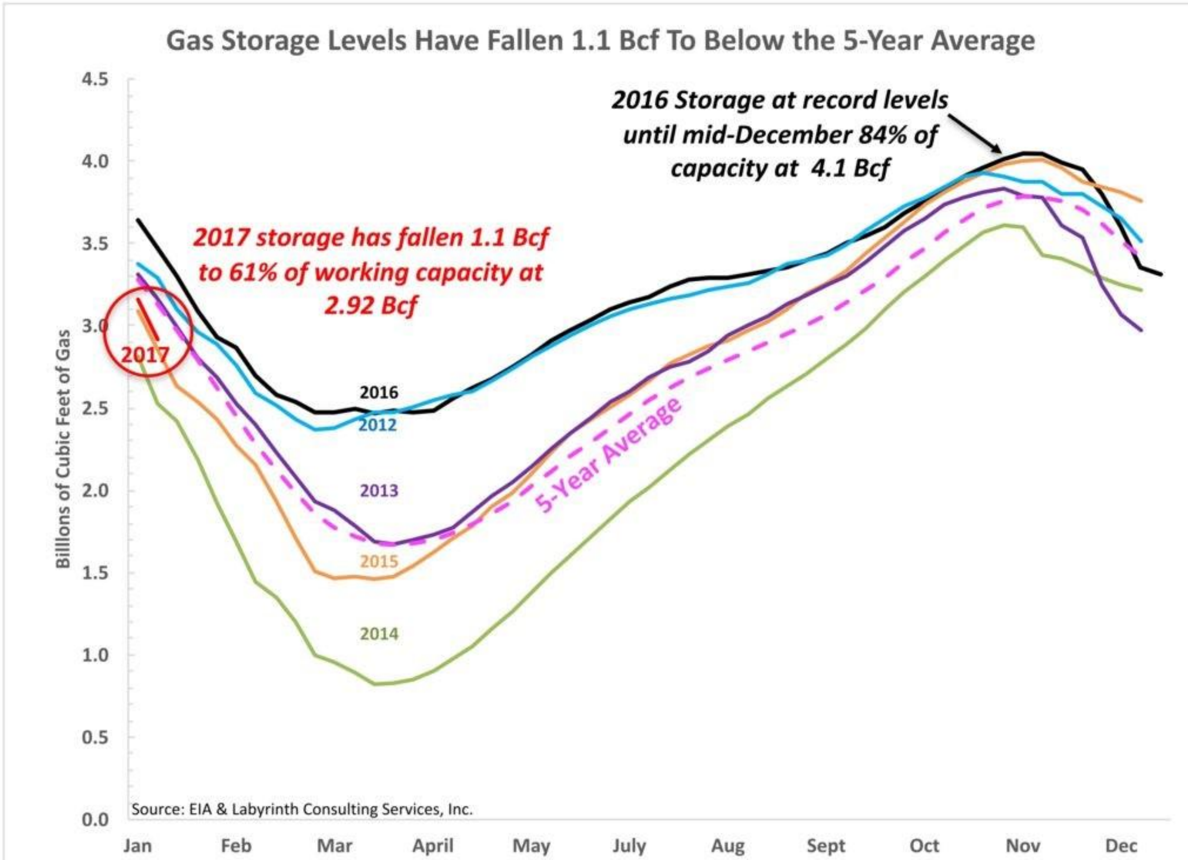

(Click to enlarge)

Figure 2. Gas Storage Levels Have Fallen 1.1 Bcf To Below the 5-Year Average. Source: EIA and Labyrinth Consulting Services, Inc.

Comparative inventory (C.I.) trends are the best indicators of gas price. These compare current storage to a moving average of levels for the same date over that last 5 years and correlate negatively with spot prices (Figure 3). C.I. fell 120% from May to December 2016 and gas prices doubled.

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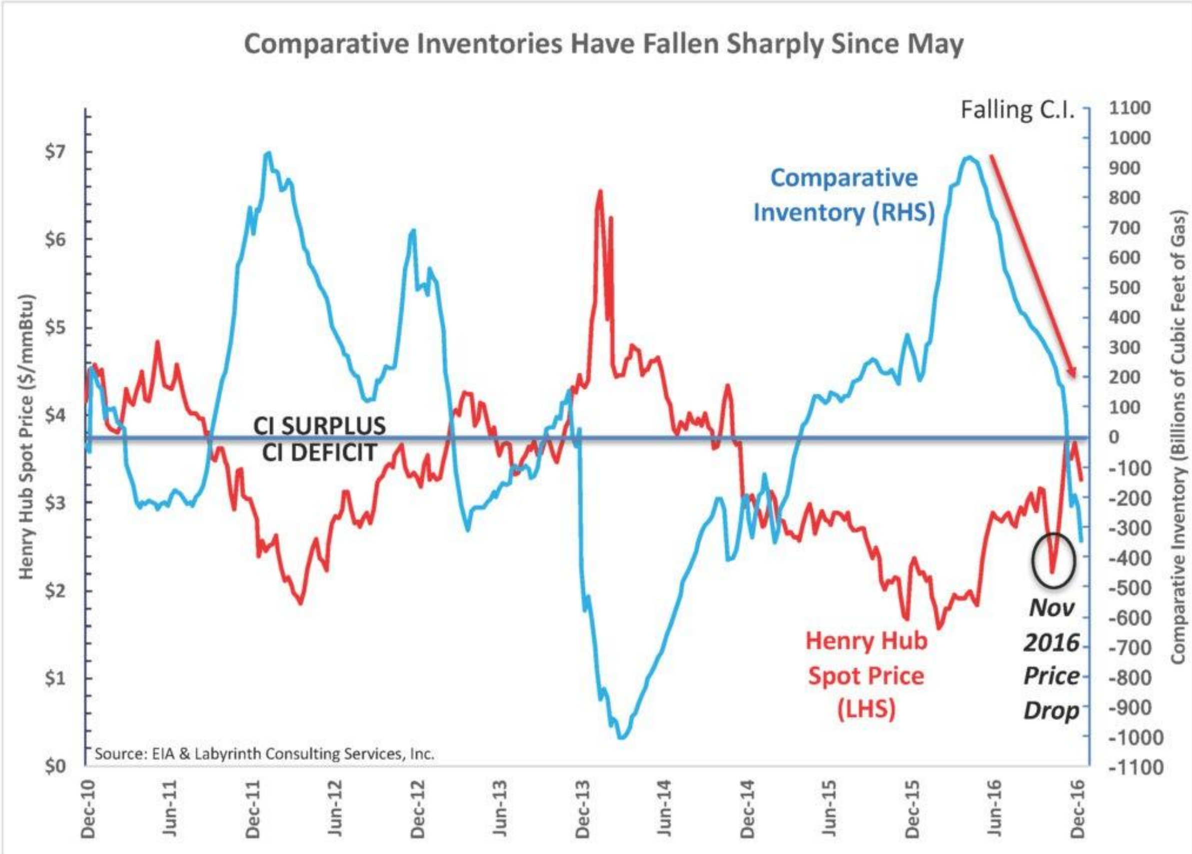

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Figure 3. Comparative Inventories Have Fallen Sharply Since May. Source: EIA and Labyrinth Consulting Services, Inc.

There are occasional short-lived excursions from the correlation. These typically occur when the market believes there is sufficient supply for the winter heating season in September or October. The market over-shoots with lower prices that are later corrected upward.

The November 2016 price drop shown in Figure 3 is an example of this phenomenon that occurred outside of the normal September-October pattern. A similar price drop began in January 2017.

R-6 Chaffee With Fuel Club Oil and 50% Increase in COG															
CC per month	Number of months	Total CC		Yearly ADTH	50	Yearly therms used	500						Existing Rates as of 2/17		
					s	Based on 80/20 split						Winter 1st 100 therm rate	$ 0.4544		
$ 28.73	12	$ 344.76										Winter over 100 therm rate	$ 0.3760		
												Summer 1st 20 therm rate	$ 0.4544		
												Summer over 20 therm rate	$ 0.3760		
Month	Actual Therms Used	1st 100 therms winter	over 100 therms winter	1st 20 therms summer	over 20 therms summer	Monthly Total Distribution	LDAC	LDAC Total	COG	COG Total	Gas Bill				
Aug-16	6			$ 2.50	$ -	$ 2.50	$ 0.1014	$ 0.56	$ 0.4200	$ 3.47	$ 35.25				
Sep-16	6			$ 2.50	$ -	$ 2.50	$ 0.1014	$ 0.56	$ 0.4200	$ 3.47	$ 35.25				
Oct-16	25			$ 9.09	$ 1.88	$ 10.97	$ 0.1014	$ 2.54	$ 0.4890	$ 18.34	$ 60.57				
Nov-16	65	$ 29.54	$ -			$ 29.54	$ 0.0553	$ 3.59	$ 0.6439	$ 62.78	$ 124.64				
Dec-16	81	$ 36.58	$ -			$ 36.58	$ 0.0553	$ 4.45	$ 0.6439	$ 77.75	$ 147.51		$ 0.36	$ 1.15	
Jan-17	105	$ 45.44	$ 1.88			$ 47.32	$ 0.0640	$ 6.72	$ 0.7276	$ 114.60	$ 197.37		$ 3.57	$ 11.54	
Feb-17	87	$ 39.53	$ -			$ 39.53	$ 0.0640	$ 5.57	$ 0.6012	$ 78.46	$ 152.29		$ 13.11	$ 1.65	
Mar-16	58	$ 26.36	$ -			$ 26.36	$ 0.1014	$ 5.88	$ 0.2634	$ 22.92	$ 83.88		$ 16.68	$ 13.19	
Apr-16	43	$ 19.31	$ -			$ 19.31	$ 0.1014	$ 4.31	$ 0.4423	$ 28.20	$ 80.55				
May-16	15			$ 6.82	$ -	$ 6.82	$ 0.1014	$ 1.52	$ 0.4117	$ 9.26	$ 46.33				
Jun-16	6			$ 2.50	$ -	$ 2.50	$ 0.1014	$ 0.56	$ 0.4400	$ 3.63	$ 35.42				
Jul-16	6			$ 2.50	$ -	$ 2.50	$ 0.1014	$ 0.56	$ 0.4400	$ 3.63	$ 35.42				
Yearly Distribution Total	500					$ 226.42		$ 36.81		$ 426.49	$ 1,034.48				
								Rolling 12 month average CGA	$ 0.4953		Equivalent Gallons	NHOEP Price	Yearly Total	Savings vs Current Rates	Savings percent
Existing Customer Yearly Total	$ 1,034.48					Customer GPM	$ 571			Oil	362	$ 2.01	$ 727.21	-$307.27	-42%
										Propane	549	$ 2.97	$ 1,630.08	$ 595.60	37%
Average Price per therm	$ 2.07														
Oil Equivalent	$ 2.86														

Average R-6 Customer

CC per month	Number of months	Total CC		Yearly ADTH	72	Yearly therms used	720						Existing Rates as of 2/17			
						Based on 80/20 split						Winter 1st 100 therm rate	$ 0.4544			
$ 28.73	12	$ 344.76										Winter over 100 therm rate	$ 0.3760			
												Summer 1st 20 therm rate	$ 0.4544			
												Summer over 20 therm rate	$ 0.3760			
Month	Actual Therms Used	1st 100 therms winter	over 100 therms winter	1st 20 therms summer	over 20 therms summer	Monthly Total Distribution	LDAC	LDAC Total	COG	COG Total	Gas Bill					
Aug-16	8			$ 3.60	$ -	$ 3.60	$ 0.1014	$ 0.80	$ 0.4200	$ 3.33	$ 36.46					
Sep-16	8			$ 3.60	$ -	$ 3.60	$ 0.1014	$ 0.80	$ 0.4200	$ 3.33	$ 36.46					
Oct-16	36			$ 9.09	$ 6.02	$ 15.10	$ 0.1014	$ 3.65	$ 0.4890	$ 17.60	$ 65.09					
Nov-16	94	$ 42.53	$ -			$ 42.53	$ 0.0553	$ 5.18	$ 0.6439	$ 60.27	$ 136.71					
Dec-16	116	$ 45.44	$ 5.99			$ 51.43	$ 0.0553	$ 6.41	$ 0.6439	$ 74.64	$ 161.21		$ 0.25	$ 1.15		
Jan-17	151	$ 45.44	$ 19.25			$ 64.69	$ 0.0640	$ 9.68	$ 0.7276	$ 110.01	$ 213.11		$ 2.48	$ 11.54		
Feb-17	125	$ 45.44	$ 9.51			$ 54.95	$ 0.0640	$ 8.02	$ 0.6012	$ 75.32	$ 167.01		$ 13.11	$ 1.65		
Mar-16	84	$ 37.95	$ -			$ 37.95	$ 0.1014	$ 8.47	$ 0.2634	$ 22.00	$ 97.15		$ 15.59	$ 13.19		
Apr-16	61	$ 27.81	$ -			$ 27.81	$ 0.1014	$ 6.21	$ 0.4423	$ 27.07	$ 89.81					
May-16	22			$ 9.09	$ 0.60	$ 9.69	$ 0.1014	$ 2.19	$ 0.4117	$ 8.89	$ 49.50					
Jun-16	8			$ 3.60	$ -	$ 3.60	$ 0.1014	$ 0.80	$ 0.4400	$ 3.48	$ 36.62					
Jul-16	8			$ 3.60	$ -	$ 3.60	$ 0.1014	$ 0.80	$ 0.4400	$ 3.48	$ 36.62					
Yearly Distribution Total	720					$ 318.54		$ 53.01		$ 409.43	$ 1,125.74					
								Rolling 12 month average CGA	$ 0.4953		Equivalent Gallons	NHOEP Price	Yearly Total	Savings vs Current Rates	Savings percent	
Existing Customer Yearly Total	$ 1,125.74					Customer GPM	$ 663			Oil	521	$ 2.32	$ 1,208.68	$82.94	7%	
										Propane	790	$ 2.97	$ 2,347.31	$ 1,221.57	52%	
Average Price per therm	$ 1.56															
Oil Equivalent	$ 2.16															

Very High Use R-6 Customer

CC per month	Number of months	Total CC		Yearly ADTH	211	Yearly therms used	2110						Existing Rates as of 2/17		
						Based on 80/20 split						Winter 1st 100 therm rate	$ 0.4544		
$ 28.73	12	$ 344.76										Winter over 100 therm rate	$ 0.3760		
												Summer 1st 20 therm rate	$ 0.4544		
												Summer over 20 therm rate	$ 0.3760		
Month	Actual Therms Used	1st 100 therms winter	over 100 therms winter	1st 20 therms summer	over 20 therms summer	Monthly Total Distribution	LDAC	LDAC Total	COG	COG Total	Gas Bill				
Aug-16	23			$ 9.09	$ 1.21	$ 10.29	$ 0.1014	$ 2.35	$ 0.4200	$ 9.75	$ 51.13				
Sep-16	23			$ 9.09	$ 1.21	$ 10.29	$ 0.1014	$ 2.35	$ 0.4200	$ 9.75	$ 51.13				
Oct-16	106			$ 9.09	$ 32.15	$ 41.24	$ 0.1014	$ 10.70	$ 0.4890	$ 51.59	$ 132.25				
Nov-16	274	$ 45.44	$ 65.54			$ 110.98	$ 0.0553	$ 15.17	$ 0.6439	$ 176.62	$ 331.50				
Dec-16	340	$ 45.44	$ 90.13			$ 135.57	$ 0.0553	$ 18.79	$ 0.6439	$ 218.74	$ 401.83		$ 0.08	$ 1.15	
Jan-17	443	$ 45.44	$ 129.01			$ 174.45	$ 0.0640	$ 28.36	$ 0.7276	$ 322.40	$ 553.93		$ 0.85	$ 11.54	
Feb-17	367	$ 45.44	$ 100.44			$ 145.88	$ 0.0640	$ 23.50	$ 0.6012	$ 220.72	$ 418.84		$ 13.11	$ 1.65	
Mar-16	245	$ 45.44	$ 54.43			$ 99.87	$ 0.1014	$ 24.82	$ 0.2634	$ 64.47	$ 217.89		$ 13.96	$ 13.19	
Apr-16	179	$ 45.44	$ 29.84			$ 75.28	$ 0.1014	$ 18.19	$ 0.4423	$ 79.33	$ 201.52				
May-16	63			$ 9.09	$ 16.28	$ 25.37	$ 0.1014	$ 6.42	$ 0.4117	$ 26.06	$ 86.58				
Jun-16	23			$ 9.09	$ 1.21	$ 10.29	$ 0.1014	$ 2.35	$ 0.4400	$ 10.21	$ 51.59				
Jul-16	23			$ 9.09	$ 1.21	$ 10.29	$ 0.1014	$ 2.35	$ 0.4400	$ 10.21	$ 51.59				
Yearly Distribution Total	2110					$ 849.81		$ 155.35		$ 1,199.85	$ 2,549.77				
								Rolling 12 month average CGA	$ 0.4953		Equivalent Gallons	NHOEP Price	Yearly Total	Savings vs Current Rates	Savings percent
Existing Customer Yearly Total	$ 2,549.77					Customer GPM	$ 1,195			Oil	1527	$ 2.32	$ 3,542.11	$992.35	28%
										Propane	2316	$ 2.97	$ 6,878.92	$ 4,329.16	63%
Average Price per therm	$ 1.21														
Oil Equivalent	$ 1.67														

Table 8.7 | GWP and GTP with and without inclusion of climate–carbon feedbacks (cc fb) in response to emissions of the indicated non-CO_2 gases (climate-carbon feedbacks in response to the reference gas CO_2 are always included).

	Lifetime (years)		GWP_{20}	GWP_{100}	GTP_{20}	GTP_{100}
CH_4[b]	12.4[a]	No cc fb	84	28	67	4
		With cc fb	86	34	70	11
HFC-134a	13.4	No cc fb	3710	1300	3050	201
		With cc fb	3790	1550	3170	530
CFC-11	45.0	No cc fb	6900	4660	6890	2340
		With cc fb	7020	5350	7080	3490
N_2O	121.0[a]	No cc fb	264	265	277	234
		With cc fb	268	298	284	297
CF_4	50,000.0	No cc fb	4880	6630	5270	8040
		With cc fb	4950	7350	5400	9560

Notes:

Uncertainties related to the climate–carbon feedback are large, comparable in magnitude to the strength of the feedback for a single gas.

[a] Perturbation lifetime is used in the calculation of metrics.

[b] These values do not include CO_2 from methane oxidation. Values for fossil methane are higher by 1 and 2 for the 20 and 100 year metrics, respectively (Table 8.A.1).

Citation that methane has a global warming potential, over the 20 year time frame, including climate-carbon feedbacks, is 86 times that of CO2, in Table 8.7 on page 714 of Chapter 8 titled Anthropogenic and Natural Radiative Forcing in

Myhre, G., D. Shindell, F.-M. Bréon, W. Collins, J. Fuglestvedt, J. Huang, D. Koch, J.-F. Lamarque, D. Lee, B. Mendoza, T. Nakajima, A. Robock, G. Stephens, T. Takemura and H. Zhang, 2013: Anthropogenic and Natural Radiative Forcing. In: *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

Online at https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf

Energy Science & Engineering

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PERSPECTIVE

A bridge to nowhere: methane emissions and the greenhouse gas footprint of natural gas

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Keywords
Greenhouse gas footprint, methane emissions, natural gas, shale gas

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Abstract

In April 2011, we published the first peer-reviewed analysis of the greenhouse gas footprint (GHG) of shale gas, concluding that the climate impact of shale gas may be worse than that of other fossil fuels such as coal and oil because of methane emissions. We noted the poor quality of publicly available data to support our analysis and called for further research. Our paper spurred a large increase in research and analysis, including several new studies that have better measured methane emissions from natural gas systems. Here, I review this new research in the context of our 2011 paper and the fifth assessment from the Intergovernmental Panel on Climate Change released in 2013. The best data available now indicate that our estimates of methane emission from both shale gas and conventional natural gas were relatively robust. Using these new, best available data and a 20-year time period for comparing the warming potential of methane to carbon dioxide, the conclusion stands that both shale gas and conventional natural gas have a larger GHG than do coal or oil, for any possible use of natural gas and particularly for the primary uses of residential and commercial heating. The 20-year time period is appropriate because of the urgent need to reduce methane emissions over the coming 15–35 years.

Introduction

Natural gas is often promoted as a bridge fuel that will allow society to continue to use fossil energy over the coming decades while emitting fewer greenhouse gases than from using other fossil fuels such as coal and oil. While it is true that less carbon dioxide is emitted per unit energy released when burning natural gas compared to coal or oil, natural gas is composed largely of methane, which itself is an extremely potent greenhouse gas. Methane is far more effective at trapping heat in the atmosphere than is carbon dioxide, and so even small rates of methane emission can have a large influence on the greenhouse gas footprints (GHGs) of natural gas use.

Increasingly in the United States, conventional sources of natural gas are being depleted, and shale gas (natural gas obtained from shale formations using high-volume hydraulic fracturing and precision horizontal drilling) is rapidly growing in importance: shale gas contributed only 3% of United States natural gas production in 2005, rising to 35% by 2012 and predicted to grow to almost 50% by 2035 [1]. The gas held in tight sandstone formations is another form of unconventional gas, also increasingly obtained through high-volume hydraulic fracturing and is growing in importance. In 2012, gas extracted from shale and tight-sands combined made up 60% of total natural gas production, and this is predicted to increase to 70% by 2035 [1]. To date, shale gas has been almost entirely a North American phenomenon, and largely a U.S. one, but many expect shale gas to grow in global importance as well.

In 2009, I and two colleagues at Cornell University, Renee Santoro and Tony Ingraffea, took on as a research challenge the determination of the GHG of unconventional gas, particularly shale gas, including emissions of methane. At that time, there were no papers in the peer-reviewed literature on this topic, and there were methane, unless the emissions of methane lead to tipping points and a fundamental change in the climate system. And that could happen as early as within the next two to three decades.

An increasing body of science is developing rapidly that emphasizes the need to consider methane's influence over the decadal timescale, and the need to reduce methane emissions. Unfortunately, some recent guidance for life cycle assessments specify only the 100-year time frame [47, 48], and the EPA in 2014 still uses the GWP values from the IPCC 1996 assessment and only considers the 100-year time period when assessing methane emissions [49]. In doing so, they underestimate the global warming significance of methane by 1.6-fold compared to more recent values for the 100-year time frame and by four to fivefold compared to the 10- to 20-year time frames [34, 37].

Climate Impacts of Different Natural Gas Uses

In Howarth et al. [8], we compared the greenhouse gas emissions of shale gas and conventional natural gas to those of coal and oil, all normalized to the same amount of heat production (i.e., g C of carbon dioxide equivalents per MJ of energy released in combustion). We also noted that the specific comparisons will depend on how the fuels are used, due to differences in efficiencies of use, and briefly discussed the production of electricity from coal versus shale gas as an example; electric-generating plants on average use heat energy from burning natural gas more efficiently than they do that from coal, and this is important although not usually dominant in comparing the GHGs of these fuels [8, 18–20]. We presented our main conclusions in the context of the heat production (Fig. 1), though, because evaluating the GHGs of the different fossil fuels for all of their major uses was beyond the scope of our original study, and electricity production is not the major use of natural gas. This larger goal of separately evaluating the GHGs of all the major uses of natural gas has not yet been taken on by other research groups either.

In Figure 5 (left-hand panel), I present an updated comparison of the GHGs of natural gas, diesel oil, and coal based on the best available information at this time (April 2014). Values are expressed as g C of carbon dioxide equivalents per MJ of energy released as in our 2011 paper [8] and Figure 1. The methane emissions in Figure 5 are the mean and range of estimates from the recent review by Brandt and colleagues [29] (see Fig. 2), normalized to carbon dioxide equivalents using the 20-year mean GWP value of 86 from the latest IPCC assessment [34]. As noted above, I believe the 20-year GWP is

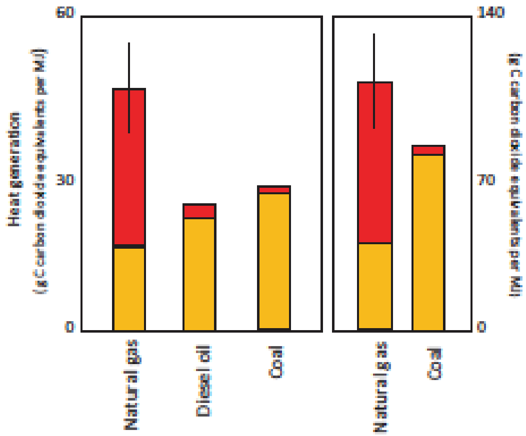
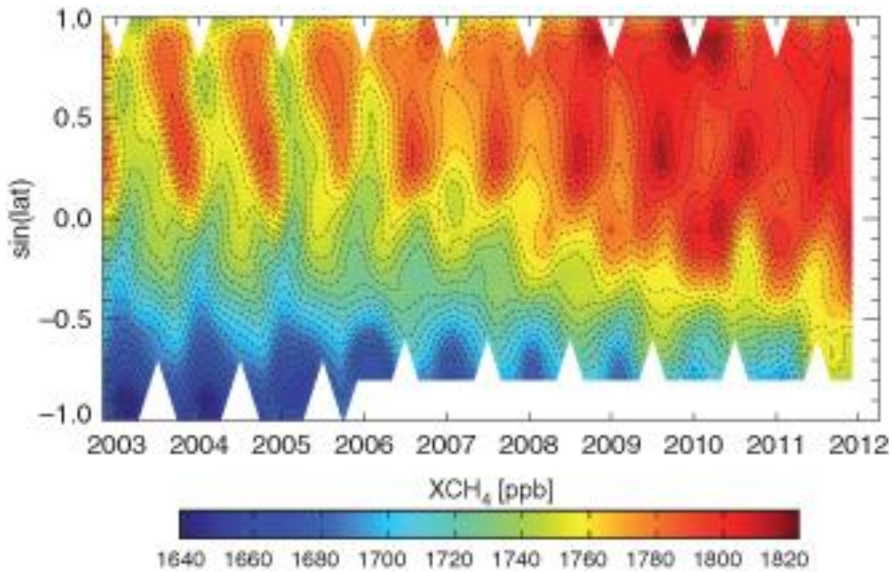


Figure 5. Comparison of the greenhouse gas footprint for using natural gas, diesel oil, and coal for generating primary heat (left) and for using natural gas and coal for generating electricity (right). Direct and indirect carbon dioxide emissions are shown in yellow and are from Howarth et al. [8], while methane emissions shown as g C of carbon dioxide equivalents using the 2013 IPCC 20-year GWP [34] are shown in red. Methane emissions for natural gas are the mean and range for the U.S. national average reported by Brandt and colleagues [29] in their supplemental materials. Methane emissions for diesel oil and for coal are from Howarth et al. [8] For the electricity production, average U.S. efficiencies of 41.8% for gas and 32.8% for coal are assumed [20]. Several studies present data on emissions for electricity production in other units. One can convert from g C of CO_2-equivalents per MJ to g CO_2-equivalents per kWh by multiplying by 13.2. One can convert from g C of CO_2-equivalents per MJ to g C of CO_2-equivalents per kWh by multiplying by 3.6.

an appropriate timescale, given the urgent need to control methane emissions globally. Estimates for coal and diesel oil are from our 2011 paper [8], using data for surface-mined coal since that dominates the U.S. market [20]. The direct and indirect emissions of carbon dioxide are combined and are the same values as in Howarth et al. [8] and Figure 1. Direct carbon dioxide emissions follow the High Heating Value convention [2, 8]. Clearly, using the best available data on rates of methane emission [29], natural gas has a very large GHG per unit of heat generated when considered at this 20-year timescale.

Of the studies listed in Tables 1 and 2 published after our 2011 paper [8], most focused just on the comparison of natural gas and coal to generate electricity, although one also considered the use of natural gas as a long-distance transportation fuel [40]. For context, over the period 2008–2013 in the United States, 31% of natural gas has been used to generate electricity and 0.1% as a transportation fuel [50]. None of the studies listed in Tables 1 and 2, other than Howarth et al. [8], considered the use of natural gas for its primary use: as a source of heat. In the United States over the last 6 years, 32% of natural gas



Global methane concentrations over time as shown by satellite data. Figure 2 in Schneising, O., Burrows, J. P., Dickerson, R. R., Buchwitz, M., Reuter, M. and Bovensmann, H. (2014), Remote sensing of fugitive methane emissions from oil and gas production in North American tight geologic formations. Earth's Future, 2: 548–558. doi: 10.1002/2014EF000265

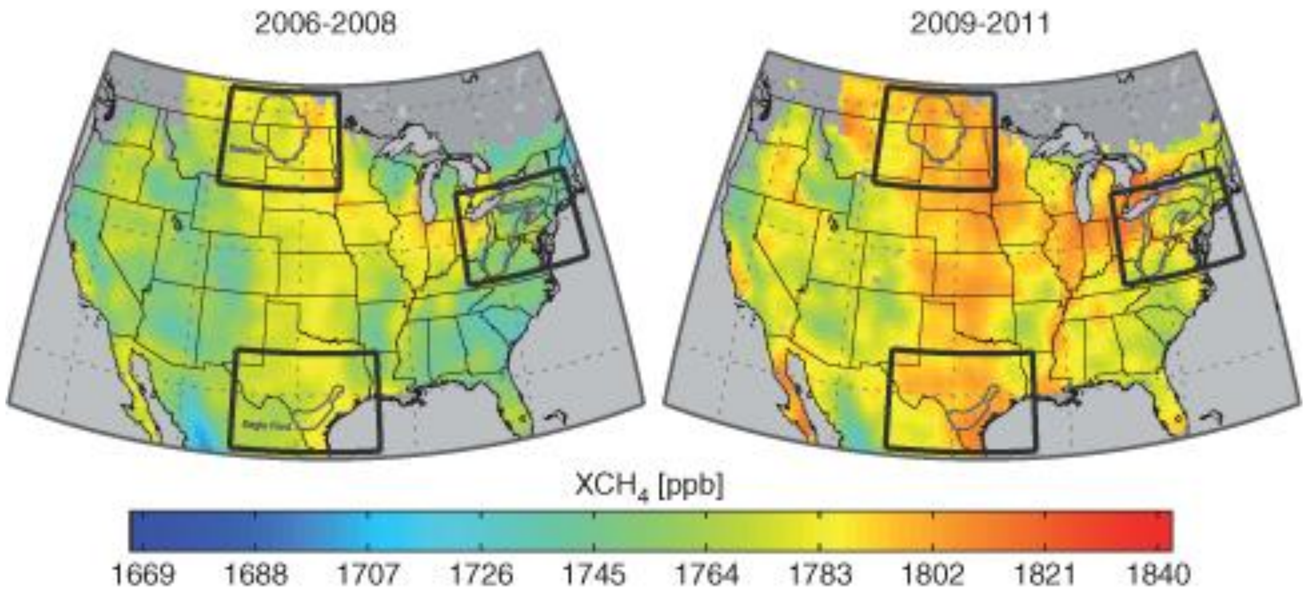
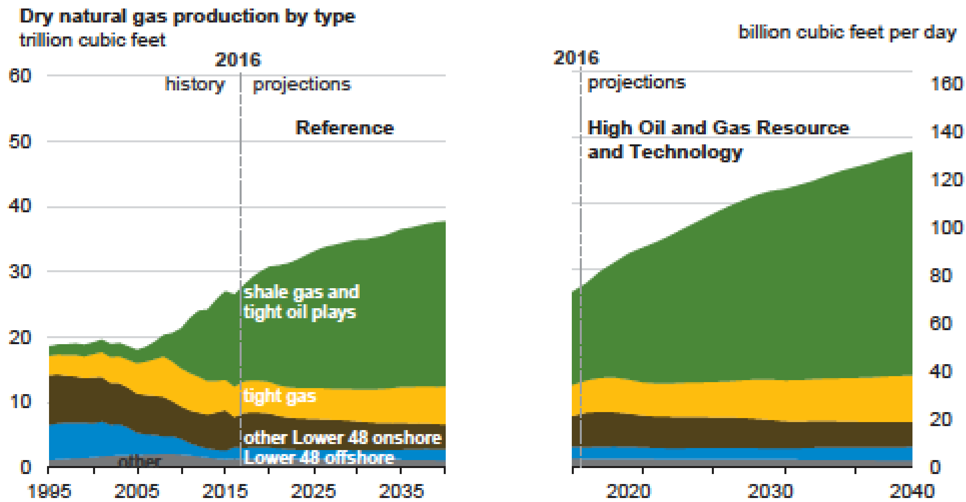


Figure 3, showing satellite data on increased concentrations of methane over major fracking areas when the periods 2006–2008 and 2009–2014 are compared.

In Schneising, O., Burrows, J. P., Dickerson, R. R., Buchwitz, M., Reuter, M. and Bovensmann, H. (2014), Remote sensing of fugitive methane emissions from oil and gas production in North American tight geologic formations. Earth's Future, 2: 548–558. doi: 10.1002/2014EF000265

U.S. natural gas production growth is the result of continued development of shale gas and tight oil plays—



—which account for nearly two-thirds of natural gas production by 2040

- Production from shale gas and associated gas from tight oil plays is the largest contributor to natural gas production growth, accounting for nearly two-thirds of total U.S. production by 2040 in the Reference case.
- Tight gas production is the second-largest source of domestic natural gas supply in the Reference case, but its share falls through the late-2020s as the result of growing development of shale gas and tight oil plays.
- As new discoveries offset declines in legacy fields, offshore natural gas production in the United States increases over the projection period.
- Production of coalbed methane generally continues to decline through 2040 because of unfavorable economic conditions for producing that resource.

Pages 57 & 58 of the U.S. Energy Information Administration report titled “Annual Energy Outlook 2017 with projections to 2050 (AE02017)

CHAFFEE HEAT LOAD			
			information source
Wood heat			
heat content (mmbtu/cord)	22.0		NH Office of Energy & Planning
woodstove efficiency	70%		NH Office of Energy & Planning
wood burned (cords)	3		Jon Chaffee
heat output (mmbtu)	**46.2**		
Oil heat			
heat content (mmbtu/gallon)	0.13869		NH Office of Energy & Planning
system efficiency	80%		NH Office of Energy & Planning
oil burned (gallons)	30		Jon Chaffee
heat output (mmbtu)	**3.3**		
Total heat load	**49.5**		

NATURAL GAS OPERATING COST PROJECTION

Feb 2017	Mar 2017	Apr 2017	May 2017	Jun 2017	Jul 2017	Aug 2017	Sep 2017	Oct 2017	Year total
7.9	6.7	4.2	2.0	0.5	0.1	0.2	1.3	3.6	49.5
78.7	66.8	42.0	19.8	5.3	0.9	2.2	13.3	35.9	495.3
98.4	83.5	52.5	24.8	6.6	1.1	2.7	16.7	44.9	619.1
100	100	100	20	20	20	20	20	20	
$28.73	$28.73	$28.73	$28.73	$28.73	$28.73	$28.73	$28.73	$28.73	***$344.76***
$44.71	$37.95	$23.87	$9.09	$3.00	$0.51	$1.24	$7.57	$9.09	***$259.27***
			$1.80					$9.36	***$18.22***
$59.16	$50.21	$31.59	$9.22	$3.04	$0.52	$1.26	$7.68	$9.22	***$333.66***
			$2.21					$11.48	***$24.98***
$6.30	$5.35	$3.36	$1.28	$0.42	$0.07	$0.18	$1.07	$1.28	***$36.52***
			$0.31					$1.59	***$3.10***
$138.91	**$122.24**	**$87.56**	**$52.63**	**$35.19**	**$29.83**	**$31.41**	**$45.04**	**$70.76**	***$1,020.52***

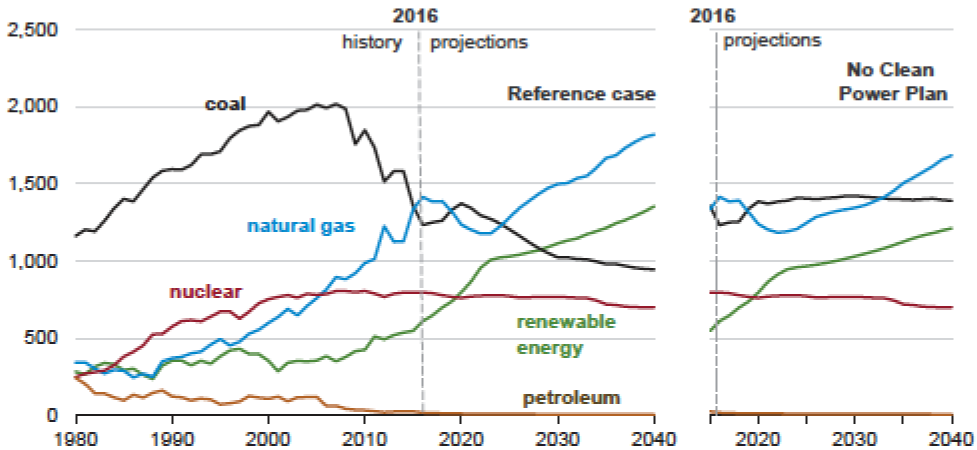
ATTACHMENT Jonathan Chaffee DG 16-852

Direct Testimony of Jonathan Chaffee, July 17, 2017

HEAT PUMPS OPERATING COST PROJECTION											
cells in yellow highlight are parameters											
Dec 2016	**Jan 2017**	**Feb 2017**	**Mar 2017**	**Apr 2017**	**May 2017**	**Jun 2017**	**Jul 2017**	**Aug 2017**	**Sep 2017**	**Oct 2017**	**Year total**
8.2	9.3	7.9	6.7	4.2	2.0	0.5	0.1	0.2	1.3	3.6	49.5
81.7	93.3	78.7	66.8	42.0	19.8	5.3	0.9	2.2	13.3	35.9	495.3
32.7	37.3	31.5	26.7	16.8	7.9	2.1	0.4	0.9	5.3	14.4	198.1
957.4	1094.0	922.7	783.1	492.7	232.4	61.9	10.6	25.7	156.2	421.0	5804.7
								uncertain about rates for these months			
$0.12010	$0.12034	$0.12796	$0.12796	$0.12796	$0.14160	$0.14160	$0.14160	$0.14160	$0.14160	$0.14160	
$0.13656	$0.13680	$0.14442	$0.14442	$0.14442	$0.15372	$0.15372	$0.15372	$0.15372	$0.15372	$0.15372	
$12.12	$12.12	$12.12	$12.12	$12.12	$14.54	$14.54	$14.54	$14.54	$14.54	$14.54	$159.96
$130.74	$149.65	$133.26	$113.10	$71.15	$35.72	$9.51	$1.62	$3.94	$24.01	$64.71	$825.81
$142.86	***$161.77***	***$145.38***	***$125.22***	***$83.27***	***$50.26***	***$24.05***	***$16.16***	***$18.48***	***$38.55***	***$79.25***	***$985.77***

Fuel prices and current laws and regulations drive growing shares of renewables and natural gas in the electricity generation mix—

U.S. net electricity generation from select fuels
billion kilowatthours



—as coal's share declines over time in the Reference case

- Fuel prices drive near-term natural gas and coal shares. As natural gas prices rebound from their 20-year lows which occurred in 2016, coal regains a larger generation share over natural gas through 2020.
- Federal tax credits drive near-term growth in renewable generation, displacing growth in natural gas.
- In the longer term, policy (Clean Power Plan, renewables tax credits, and California's SB32) and unfavorable economic conditions compared with natural gas and renewables result in declining coal generation and growing natural gas and renewables generation in the Reference case.

Pages 69 & 70 of the U.S. Energy Information Administration report titled "Annual Energy Outlook 2017 with projections to 2050 (AE02017)

Lebanon Tweaks City Plan

By Tim Camerato
Valley News Staff Writer
Wednesday, July 12, 2017

Lebanon — Passages encouraging the expansion of natural gas in Lebanon have been effectively removed from the Master Plan in an effort to clarify the city's stance on renewable energy.

The Planning Board voted unanimously on Monday night to approve an addendum that removes references supporting "natural gas" and "liquefied natural gas" from the city's guiding document. The move came on the heels of similar votes of support from the City Council and the ad hoc Lebanon Energy Advisory Committee.

Officials said the change was needed to correct mistakes made when the Master Plan was completed in 2012.

At the time, many thought natural gas would be an effective "bridge fuel," used as businesses make the transition from fossil fuels to more environmentally friendly energy sources. But research has since shown that extracting and transporting natural gas has the potential to be just as damaging as traditional coal and fuel oils.

"It's a distinct inconsistency in the Master Plan," Councilor Clifton Below said on Monday, referring to the inclusion of natural gas alongside other renewable sources.

As the plan suggests goals toward making Lebanon sustainable, it supports those goals with evidence and texts backing up assertions, said Below, who also is the chairman of the city's Energy Advisory Committee.

"This particular point is not (supported)," he said, according to an audio recording of the meeting. "Fracked natural gas from western Pennsylvania is not a renewable resource." Fracking, also known as hydraulic fracturing, is the process of injecting a water mixture at high pressures to break up underground rock formations and extract natural gas. The practice is controversial, and some scientists have drawn connections between increased instances of fracking and earthquakes.

Although the addendum sought to promote environmentally friendly practices, much of the discussion on Monday focused on timing and whether it would be procedurally appropriate. Liberty Utilities currently is before the state's Public Utilities Commission seeking approval to obtain a natural gas franchise. The company hopes to build a facility near the Lebanon landfill on Route 12A, where natural gas would be piped along a route into downtown Hanover.

Two members of the Energy Advisory Committee — Ariel Arwen and Jonathan Chaffee — are intervenors in the review and have promoted the addendum to prevent the Master Plan from being used in support of the proposed pipeline.

“Policy is what creates the perception and we’re looking at changing policy mid-stride,” Planning Board member Carl Porter said in the audio recording.

Porter worried approving the changes could be seen as the city opposing Liberty’s proposal. While Lebanon is an intervenor in the PUC review, it has not taken a formal stance on the pipeline.

“If there was no application, I would have no question in my mind about this,” he said, adding that changing direction while proceedings are ongoing at the state level could be seen as “setting up an expectation and then ripping it away.”

However, Liberty Utilities has not used the Master Plan in testimony before regulators, and Michael Licata, the company's government relations director, told the Planning Board on Monday it doesn’t intend to in the future.

Valley Green Natural Gas, a former competitor to the Liberty Utilities proposal, made note of the Master Plan in one of its filings, Below said. But that company bowed out of a review last year after making a deal with Liberty.

“I think this is actually an ideal time to take action on this, just to clean up our Master Plan,” Below said in the recording. “It (removes any bias of) the city, if anything. It’s taking no position one way or another on natural gas.”

Below, a former PUC commissioner, also acknowledged that some might try to use the addendum to make the case that Lebanon opposes a pipeline.

“I don’t think that will make a hill of beans’ difference to the commissioners because, having been a commissioner for six years, I know the criteria that they have to judge the case on, and that’s just not going to be material to their decision,” he said.

The commission evaluates each franchise petition on the basis of a company’s “managerial, technical and financial capacity.” In the past, it also rejected arguments based on climate change concerns, saying its job is to determine whether a project has the ability to operate successfully.

Some Planning Board members also expressed concern with how the addendum would be approved. The Master Plan was adopted in 2012 and a review for possible revisions isn’t expected until roughly two years from now.

“I’m just troubled about opening up changes to the Master Plan mid-course over something that doesn’t appear to be urgent,” Planning Board member Bruce Garland said in the recording.

However, Lebanon Senior Planner Tim Corwin said the board has made at least one change to the Master Plan since 2012, and it could be much longer than two years before its renewable energy chapter is up for review.

Other board members also countered that since Liberty doesn't have a proposal under review on a city level, it is legally free to make decisions and talk freely about natural gas.

"I feel it would be irresponsible of any planning group in our city to ignore what has been proven scientifically in community after community, state after state, city after city," board member Joan Monroe said.

Those in attendance agreed. Devin Wilkie, an intervenor in the Liberty review, said he works for a publisher. When a book needs correcting, he said, his company doesn't wait for the next edition to fix mistakes.

"Otherwise the material we have out is wrong," he said in the recording. "I don't think it should necessarily be that we halt progress simply because we don't want it to be seen the wrong way."

On Tuesday, Arwen applauded the Planning Board's decision, saying it supports the Master Plan's goal to promote sustainability.

"I feel we live in a moment poised with crucial choices. The energy chapter charges the city with being an innovative regional leader, inspiring its residents and businesses to move toward sustainability via energy efficiency and renewable energy sources," she said.

"I hope the Planning Board's unanimous vote reinvigorates that charge and the city engages even more proactively with various sectors in our community to address pathways to sustainability."

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