BENEFITS OF AND CHALLENGES TO ENERGY ACCESS IN THE 21ST CENTURY: FUEL SUPPLY AND ENERGY INFRASTRUCTURE

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY AND POWER

OF THE

COMMITTEE ON ENERGY AND COMMERCE

HOUSE OF REPRESENTATIVES

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BENEFITS OF AND CHALLENGES TO ENERGY ACCESS IN THE 21ST CENTURY: FUEL SUPPLY AND ENERGY INFRASTRUCTURE

THURSDAY, MARCH 6, 2014

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENERGY AND POWER,
COMMITTEE ON ENERGY AND COMMERCE,
Washington, DC.

The subcommittee met, pursuant to call, at 9:02 a.m., in room 2123 of the Rayburn House Office Building, Hon. Ed Whitfield (chairman of the subcommittee) presiding.

Members present: Representatives Whitfield, Scalise, Shimkus, Pitts, Terry, Latta, Olson, McKinley, Gardner, Pompeo, Griffith, Barton, Upton (ex officio), Rush, McNerney, Tonko, Barrow, Christensen, Castor, and Waxman (ex officio).

Staff present: Nick Abraham, Legislative Clerk; Charlotte Baker, Press Secretary; Sean Bonyun, Communications Director; Allison Busbee, Policy Coordinator, Energy and Power; Patrick Currier, Counsel, Energy and Power; Tom Hassenboehler, Chief Counsel, Energy and Power; Jason Knox, Counsel, Energy and Power; Mary Neumayr, Senior Energy Counsel; Chris Sarley, Policy Coordinator, Environment and Economy; Tom Wilbur, Digital Media Advisor; Alison Cassady, Democratic Senior Professional Staff Member; Greg Dotson, Democratic Staff Director, Energy and Environment; and Ryan Skukowski, Democratic Assistant Clerk.

OPENING STATEMENT OF HON. ED WHITFIELD, A REPRESENTATIVE IN CONGRESS FROM THE COMMONWEALTH OF KENTUCKY

Mr. WHITFIELD. I would like to call the hearing to order this morning, and we have a panel of eight witnesses this morning, and we look forward to the testimony of all of you, and your expertise and assistance to the committee. This morning's hearing is the second in a series entitled "Benefits of and Challenges to Energy Access in the 21st Century". Last week we focused on access to electricity, and today we want to turn our attention to fuel supply and infrastructure issues. We really look forward to this hearing this morning because we have representatives of the pipeline, railroad, and trucking industries, as well as others, to give the perspective on what we need to be doing to make sure that we take advantage of our current energy opportunities in America.

[The prepared statement of Mr. Whitfield follows:]

PREPARED STATEMENT OF HON. ED WHITFIELD

North America's oil and natural gas output has been growing since 2007, and the Energy Information Administration expects continued increases in the years ahead. This poses a challenge to the nation's existing energy infrastructure—be it pipelines, railroads, or trucking. For one thing, this infrastructure is being called upon to carry more energy than ever before. For another, most of it does not serve the areas where energy production is rapidly increasing, such as the oil-rich Bakken formation in North Dakota and the gas fields in Pennsylvania.

There is no question that the energy boom is great news for the U.S. But without an infrastructure boom to match it, the benefits of our energy abundance will not be fully realized.

Recent events have shown the energy infrastructure to be under strain. For example, very tight natural gas supplies and high prices in New England during this very cold winter were not caused by any actual shortages but by the limited pipeline capacity serving that region. And the low supplies of propane that hit my district and many rural areas throughout the Midwest were attributable in part to the fact that we now have booming production of crude oil that is competing for space on trains and trucks with other commodities like propane.

And I might add that the trains in turn are overburdened with oil in part because oil pipeline capacity has not been able to expand to keep up with rising production. So each element of our infrastructure system is interconnected with the others. Indeed, just as we benefit from energy diversity—coal, oil, natural gas, nuclear, and renewables—we also benefit from infrastructure diversity, but only if each mode of transport is allowed to expand to meet current and future demand.

Unfortunately, the Obama administration has been considerably less than proactive in addressing our infrastructure challenges. We are all familiar with the administration's 5-year-long delay in approving the Keystone XL pipeline expansion project. And Keystone is indicative of a larger indifference if not hostility towards infrastructure upgrades, especially those that carry fossil fuels. I fear that the Keystone XL delays and other instances of infrastructure obstructionism may be a part of the administration's climate agenda.

Compounding Keystone XL and other project delays are proposed regulatory actions that may make it much harder to transport oil and other fuels by rail. We need regulations that facilitate the safe transportation of energy rather than limit it.

The House is already acting to address several infrastructure bottlenecks. In addition to passing H.R. 3 to greenlight Keystone XL, we have also passed H.R. 1900, the "Natural Gas Permitting Reform Act," that would expedite and streamline future natural gas pipeline approvals. And this committee has introduced H.R. 3301, the "North American Energy Infrastructure Act," to reduce unnecessary red tape for approvals of energy projects that cross the Canadian or Mexican border and thus help create a more integrated North American energy infrastructure.

And we continue to consider other measures that would help give this nation a more robust 21st century energy infrastructure. I look forward to hearing from representatives of the pipeline, railroad, and trucking industries as well as others to give their perspective on what else is needed. Thank you.

Mr. WHITFIELD. You didn't even start my time, and I am already through with my remarks. So at this time I would like to introduce Mr. McNerney of California for his opening statement.

OPENING STATEMENT OF HON. JERRY MCNERNEY, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF CALIFORNIA

Mr. MCNERNEY. Thank you, Mr. Chairman, and good morning. This is our second hearing on energy access, and I think it is an important topic. As we have seen in New England, we have had price hikes, gas shortages, and there are other infrastructure concerns that we need to think about. The good news, of course, is that we are seeing a tremendous amount of natural gas and oil production. I think we are the biggest producer in the world as of last year. Well, the relatively bad news is we don't quite have the infrastructure to make sure that all of our potential domestic customers have good access to this wonderful bounty that we are having, so it is important to hear from the witnesses this morning.

We need to maximize what resources we have so that we can improve our manufacturing base. I think that is one of the real benefits of this, is that we have an opportunity now to regain our stature as the premier manufacturing center of the world. And with your all help out here, this is going to happen. So we want to hear what your thoughts and ideas are on how we can move forward. There needs to be a partnership between the Federal government and the local governments, on the one hand, and industry that is going to make these investments. We have some complaints about the regulatory process, how long it takes to get permits, and hearing how we can best move forward while maintaining public safety is critical.

We need to worry about methane leaks into the atmosphere, so that means finding the best technology out there to prevent methane, which is a greenhouse gas. So we want to make sure that the technology is not only available, but that it is being implemented properly. And we would need to make sure that there is continued oversight so that when gas lines, oil lines, get put in, that they are monitored properly. No one in this panel benefits when there is a leak, when there is a disaster. And if we work together in a way that prevents those from happening, and gets potential bad players out of the market, then everyone is going to benefit.

We also need to have an environment where investment is encouraged. And, again, overregulation won't do that, but under-regulation won't do it either, so we need some strong public/private partnerships.

And, with that, Mr. Chairman, I am going to yield back. I believe we have votes called within an hour, so——

Mr. WHITFIELD. Thank you very much. Mr. Upton is not here, Mr. Waxman is not here, so if they come in later and want to make a statement, we will recognize them at that time. But in the meantime, I am sorry, you are not going to hear any more from us. We are going to give you all the opportunity to talk. So, on our panel today, we have Mr. Adam Sieminski, who has been here before, the administrator over at the U.S. Energy Information Administration, Mr. Donald Santa, who is the CEO, president, of the Interstate Natural Gas Association of America. We have Mr. Richard Roldan, who is president and CEO of the National Propane Gas Association, Mr. Andrew Logan, who is the Director of Oil and Gas and Insurance Programs at Ceres. And we have Mr. "Shorty" Whittington, who is president of Grammer Industries, on behalf of the American Trucking Association and the National Tank Truck Carriers. We have Mr. Michael Obeiter, who is with the Climate and Energy Program, Senior Associate, at the World Resources Institute. We have Mr. Andrew Black, who is president of the Association of Oil Pipe Lines. And then we have Mr. Ed Hamberger, who is the president and CEO of the Association of American Railroads.

So each one of you will be recognized for 5 minutes for your opening statement. And, as you know, we have the little boxes, and when it turns red, that means the time is up. If it is green, you can keep talking. So, Mr. Sieminski, we will begin with you, and you are recognized for 5 minutes for your opening statement. And be sure and turn your microphone on.

STATEMENTS OF ADAM SIEMINSKI, ADMINISTRATOR, ENERGY INFORMATION ADMINISTRATION, DEPARTMENT OF ENERGY; DONALD F. SANTA, PRESIDENT AND CHIEF EXECUTIVE OFFICER, INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA; RICHARD R. ROLDAN, PRESIDENT AND CHIEF EXECUTIVE OFFICER, NATIONAL PROPANE GAS ASSOCIATION; ANDREW LOGAN, DIRECTOR, OIL AND GAS INDUSTRY PROGRAMS, CERES; CHARLES "SHORTY" WHITTINGTON, PRESIDENT, GRAMMER INDUSTRIES, INC., ON BEHALF OF AMERICAN TRUCKING ASSOCIATION, INC., AND NATIONAL TANK TRUCK CARRIERS; MICHAEL OBEITER, SENIOR ASSOCIATE, CLIMATE AND ENERGY PROGRAM, WORLD RESOURCES INSTITUTE; ANDREW J. BLACK, PRESIDENT, ASSOCIATION OF OIL PIPE LINES; AND EDWARD R. HAMBERGER, PRESIDENT AND CHIEF EXECUTIVE OFFICER, ASSOCIATION OF AMERICAN RAILROADS

STATEMENT OF ADAM SIEMINSKI

Mr. SIEMINSKI. All right. Chairman Whitfield, Mr. McNerney, members of the committee, thank you for the opportunity to be here today. As you know, EIA is a statistical and analytical agency at the Department, and by law our data analyses are independent of approval by any other office or employee of the Federal government, so these views should not be construed as representing those of the Department of Energy or any other Federal agency.

EIA is providing data and analysis related to the winter fuels markets. This winter we have been working very closely with the Department of Energy's energy response organization to provide critical market information to public officials, industry, and consumers. This winter's cold weather increased both consumption and prices of heating fuels nationally. This winter season has been the coldest since 2002–3, and in the Midwest the coldest since the winter of 1978–79.

Let me talk a little bit about propane. U.S. propane supplies hit record highs last year due to increased oil and natural gas production. With supply growing faster than domestic demand, the U.S. has become a net exporter of propane in recent years, although imports have continued to play an important role, particularly in the upper Midwest and the Northeast of the United States. Last fall, a record corn harvest coincided with very wet weather to increase demand for propane in the Midwest for crop drying. As a result, propane stocks in the Midwest were at their lowest level for November since 1996. Stocks were further reduced when cold weather hit the Midwest in late December and early January.

There are two major hubs for propane in the mid-continent, Mont Belvieu, Texas, which is really on the Gulf Coast, and Conway, Kansas, in Central Kansas. Under market conditions that prevailed from March 2010 to November 2013, prices at Mont Belvieu were generally above those at Conway, and that provided a signal for supplies to move towards the Gulf Coast. Most pipelines between the hubs carry supplies southward. Rail is the primary mode available to move propane northward from Mont Belvieu up into Conway.

At the beginning of December, wholesale prices, as reported by Reuters, were nearly equal at Conway and Mont Belvieu. The development of extreme propane shortages in the Midwest in January led to a significant rise in prices at Conway, and that provided a strong incentive for increased flows back up north to the Conway hub, and other consuming areas, by a variety of modes, including trucks. Imports also increased, with more propane flowing into Minnesota and Michigan via pipelines from Canada, and additional European tanker cargoes coming into the Northeast of the United States. Many States declared emergencies to enable more delivery of propane throughout the Midwest to both wholesalers and retail customers.

Now I am going to talk just a little bit about natural gas. Cold weather affected natural gas markets, including new record high withdrawal of natural gas from storage, and a surge in natural gas prices. On February 21, storage levels were below the previous 5-year minimum, and natural gas prices at Henry hub increased from $4.32 per million BTUs up to as high as $8.15 on February 10. In contrast to markets for propane and heating oil, however, where wholesale prices are quickly reflected in retail prices, electricity and natural gas rates paid by consumers who receive service through their local distribution utilities did not immediately reflect the spot market prices.

New England faces some of the highest and most volatile spot natural gas prices, reflecting both pipeline capacity constraints and growth in demand, particularly for electricity generation. Reductions in imports of liquefied natural gas, LNG, and Canadian pipeline gas added to the strain on pipelines serving New England that carried domestically sourced natural gas.

So natural gas spot prices in New England hit record levels this winter. Price for the first 50 days of 2014 averaged 50 percent higher than prices during a comparable period in 2013. Winter spot prices for natural gas in New England were also higher on average, and more volatile than elsewhere in the United States, although prices were high all over the U.S. In fact, EIA released a special report last January, which is included in my testimony, that talks about this in detail. An updated analysis for this winter, also included in my testimony, discusses a number of potential ways to lessen the impact of limited peak natural gas supply at peak demand periods, including pipeline expansions, additional fuel substitution by electric generators and other gas customers, and ways to save on the demand side.

I am going to end there. Thank you for the opportunity to testify, and I look forward to answering questions.

[The prepared statement of Mr. Sieminski follows:]

STATEMENT OF ADAM SIEMINSKI

ADMINISTRATOR

ENERGY INFORMATION ADMINISTRATION

U.S. DEPARTMENT OF ENERGY

Before the

SUBCOMMITTEE ON ENERGY AND POWER

COMMITTEE ON ENERGY AND COMMERCE

U. S. HOUSE OF REPRESENTATIVES

MARCH 6, 2014

ADAM SIEMINSKI, ADMINISTRATOR, ENERGY INFORMATION ADMINISTRATION (EIA)
Hearing: Benefits of and Challenges to Energy Access in the 21st Century: Fuel Supply and Infrastructure, March 6, 2014, U. S. House of Representatives

SUMMARY

Temperatures east of the Rocky Mountains have been significantly colder this winter compared with the same period last winter and the previous 10-year average, putting upward pressure on both fuel consumption and the prices of fuels used for heating.

The continuing development of U.S. hydrocarbon resources, resulting in the increasing supply of crude oil, natural gas, and propane and other natural gas liquids has and will continue to present both challenges and opportunities for the use of existing infrastructure and the future development of additional infrastructure.

Propane: U.S. propane supply set record highs in 2013, driven by increased oil and natural gas production, with supplies derived from natural gas production growing faster than refinery-based sources. The location and rate of growth have challenged the existing infrastructure and delivery patterns.

Cold temperatures tightened supplies in the both the Midwest and the East that were already low heading into the winter heating season, in part due to late fall consumption of propane to dry a large and wet corn crop. Residential propane prices in the Midwest more than doubled between the beginning of December and late January, but have declined substantially over the past 5 weeks. (EIA provides weekly residential pricing information during the winter fuels season through the State Heating Oil and Propane Program, a cooperative data collection effort with state energy offices.)

Under market conditions that prevailed from March 2010 to November 2013, prices at Mont Belvieu had been generally above those at Conway, providing a signal for supplies to move towards the Gulf Coast. However, the development of extreme propane shortages in the Midwest in mid-January led to a significant rise in prices at Conway, KS (the main Midwest hub) relative to those at Mont Belvieu, TX (the main Gulf Coast hub) providing a strong incentive for northward flows. High prices in Midwest and Northeast markets also encouraged increased import flows, with more propane flowing into the Midwest via pipeline and additional tanker cargoes coming into Northeast ports. Propane inventory levels in the Midwest and Northeast are still below the five-year seasonal average, but the gap has diminished in recent weeks.

Natural gas: Cold weather this winter contributed to a new record-high withdrawal of natural gas from storage and a surge in natural gas spot prices. Spot prices in the region were 50% above the same period in 2013. New England continues to face some of the highest and most volatile spot natural gas prices reflecting both significant growth in demand for natural gas, particularly for electricity generation, and capacity constraints of pipelines serving the region.

Chairman Whitfield, Ranking Member Rush, and Members of the Committee, thank you for the opportunity to appear before you today.

The U.S. Energy Information Administration (EIA) is the statistical and analytical agency within the U.S. Department of Energy. EIA collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding regarding energy and its interaction with the economy and the environment. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government, so the views expressed herein should not be construed as representing those of the Department of Energy or any other Federal agency.

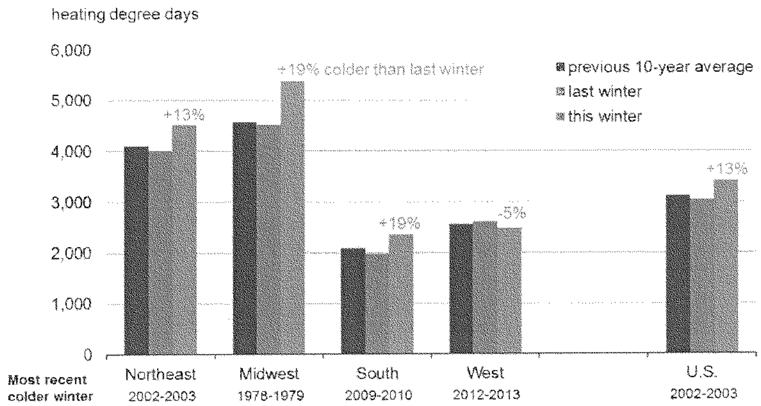
As discussed in my testimony, EIA is active in providing both data and analysis specifically related to winter fuels markets, including forecasts of average heating fuel expenditures by region and primary heating fuel. EIA reports on the status of fuels markets through many channels, including the Weekly Petroleum Status Report, This Week in Petroleum, the Weekly Natural Gas Storage Report, the Natural Gas Weekly Update, the monthly Short Term Energy Outlook and in numerous short analyses in Today in Energy. From October through March, in cooperation with participating States, EIA publishes the Heating Oil and Propane Update weekly. Since January EIA has had a dedicated Energy Market Alerts section on the website and has been working closely with the Department of Energy's Energy Response Organization to provide critical market information to the public officials, industry and consumers.

Every year, the October issue of the Short Term Energy Outlook, which reflects the latest available winter weather forecast provided by the National Oceanographic and Atmospheric Administration (NOAA), serves as the basis for EIA's presentation at the Winter Fuels Outlook conference organized by the National Association of State Energy Officials. All estimates are updated regularly as the winter progresses.

Weather

As we now know, temperatures east of the Rocky Mountains have been significantly colder this winter (October - February) compared with the forecast used in developing the Winter Fuels Outlook, the same period last winter, and the previous 10-year average, putting upward pressure on both fuel consumption and the prices of fuels used for heating. U.S. average heating degree days (HDD) were 13% higher than last winter (indicating colder weather) and 10% above the previous 10-year average. Compared to last winter, the Northeast has been 13% colder, the Midwest 19% colder, and the South 19% colder, while the West has been 5% warmer. For the United States as a whole, this October through February period has been the coldest since 2002-03, while the Midwest has not been colder since 1978-79.

Heating demand indicators, October through February



Source: EIA, Short-Term Energy Outlook, February 2014
Note: Based on NOAA actuals through the week ending March 1.

Recent cold weather had the greatest effect on propane prices, particularly for consumers in the Midwest. Cold temperatures tightened supplies in the both the Midwest and the East that were already low heading into the winter heating season, in part due to late fall consumption of propane to dry a large and wet corn crop. Residential propane prices in the Midwest rose from an average of $2.08 per gallon (gal) on December 2, 2013, to $4.20/gal on January 27; retail prices fell back to $3.83/gal on February 3 and $2.78/gal by March 3. To a lesser extent, cold temperatures tightened heating oil supplies and helped drive up retail prices. However, while both average prices and consumer expenditures for homes heated with propane are likely to be substantially higher this winter than last, EIA still expects that U.S. heating oil prices this winter will average slightly below those in the winter of 2012-13.

Developments in wholesale propane and heating oil markets are quickly reflected in retail prices. Higher retail prices for propane and heating oil directly affect the out-of-pocket cost of fuels purchases by customers who use these fuels for heating. In recent years, propane and heating oil prices delivered to residential consumers have been substantially higher than delivered natural gas prices on an energy content basis, a situation that was exacerbated during recent price spikes. For example, the Midwest average retail propane price of $4.20/gal during the week of January 27 was five times the estimated national average delivered price of natural gas to residential consumers during January on an energy-equivalent basis.

EIA has been able to provide current pricing information during the winter fuels season because of our cooperative data collection efforts with the State Energy Offices through the State Heating Oil and Propane Program (SHOPP). For the months of October through Mid-March, EIA provides 50/50 cost sharing for the states that choose to participate to make weekly telephone calls to retail heating oil and propane outlets. EIA creates and maintains the sample for each State and releases the data, which is closely watched by policymakers, consumers, and analysts, every Wednesday as part of the Weekly Petroleum Supply Report.

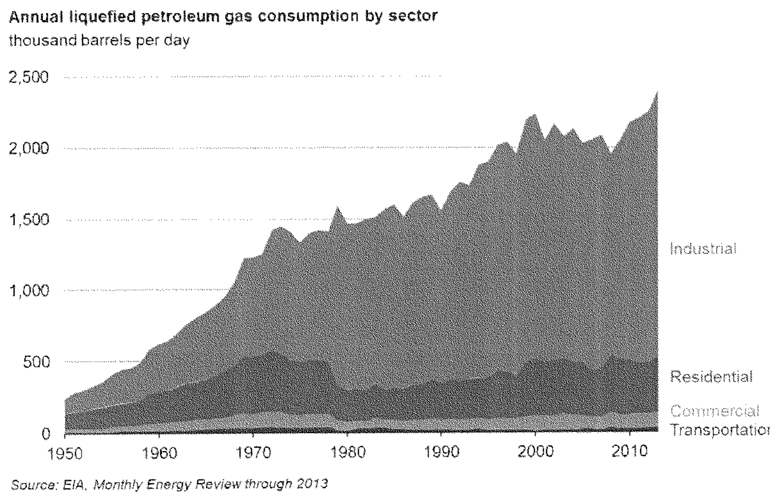
The rest of my testimony will focus on propane markets across the Midcontinent and on the natural gas market, with an emphasis on New England.

Propane

Propane is produced from natural gas at processing plants, usually located in areas where natural gas is produced, at fractionating plants that further process mixed natural gas liquids separated at processing plants, and from crude oil at refineries. Propane from natural gas has been the fastest-growing component of overall U.S. propane production. U.S. supply set record highs on an almost weekly basis in 2013 as a result of increased oil and natural gas drilling.

There are two major hubs for propane in the Midcontinent: Mont Belvieu, Texas (on the Gulf Coast) and Conway, Kansas (in central Kansas). With the rapid growth in U.S. propane supply, domestic production has exceeded domestic consumption, and the United States has become a net propane exporter. Exports from the United States, primarily shipped via tanker from the U.S. Gulf Coast (PADD 3) were 402,000 barrels per day in December. However, the United States has also continued to import significant amounts of propane (121,000 barrels per day in December) via tanker into Northeast (PADD 1) ports, and via several pipelines that carry supplies from Canada into the Midwest (PADD 2) particularly Minnesota and Michigan.

The largest market nationally for propane and propylene is the industrial sector, including agriculture. Propane is also used heavily in the residential and commercial sectors in more rural areas that may lack natural gas infrastructure. Residential and commercial demand has a strong seasonal pattern, with a winter peak to meet heating needs.



Last fall, a record corn harvest increased the demand for propane in the Midwest. Because propane is used for crop drying, a wet growing season in the Midwest combined with the largest corn yield in U.S. history greatly increased the demand for propane. On December 12, 2013, EIA reported in Today in Energy, Propane demand hits a record high for November, "For the week ending November 1, the United States consumed nearly 1.8 million barrels per day—a figure typically not seen until January or February, when the winter heating season reaches a peak. As a result, propane inventories in PADD 2 (the Midwest) were at their lowest level for November since 1996." (Attached as Exhibit A.) The winter heating season began with propane stocks already below the five-year average nationally.

The market for propane in the Midwest (PADD 2) is somewhat fragmented, with low concentrations in rural areas. On average, 7% of homes in the region use propane as a primary heating fuel. The most recent Propane Situation Update (attached as Exhibit B) shows the share and number of homes heated with propane in the Midwest and New England on page 5.

Cold weather hit the Midwest in late December and early January, with heating degree days in the region roughly 15% higher than the 10-year average levels. The states of Indiana, Iowa, Minnesota, Montana, Nebraska, South Dakota, and Wisconsin declared states of emergency to enable more delivery of propane throughout the Midwest.

Propane Infrastructure developments

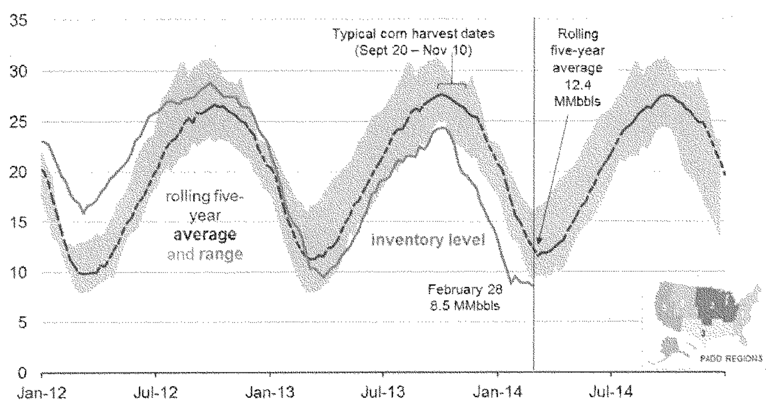
The growth of U.S. production of propane and other natural gas liquids (NGL) has led to several recent and proposed changes in NGL pipeline systems.

Some of the propane supply to the Midwest and Northeast is transported by common-carrier pipelines, which establish shipping schedules in advance and are constrained in rescheduling nominations to meet unexpected shortages in their delivery regions. In early February, the Federal Energy Regulatory Commission invoked its emergency authority under the Interstate Commerce Act, for the first time ever, to direct Enterprise TE Products Pipeline Company (TEPPCO) to temporarily provide priority treatment to propane shipments from Texas to the Midwest and the Northeast.

The Cochin pipeline, which carries propane from Canada into Minnesota, was out of service for planned maintenance in late 2013 related to plans to repurpose and reverse the pipeline as early as mid-2014. Import flows into the Upper Midwest via this pipeline were cut off during this planned outage.

Propane stocks in the Midwest stood at 8.5 million barrels for the week ending February 28, a 4 percent decrease from the previous week. Inventory levels are still below the five-year seasonal average, but the gap is diminishing—levels that had been as much as 8.6 million barrels below the five-year average on January 10 were 3.8 million barrels below the five-year average as of February 28.

PADD 2 propane inventories
million barrels



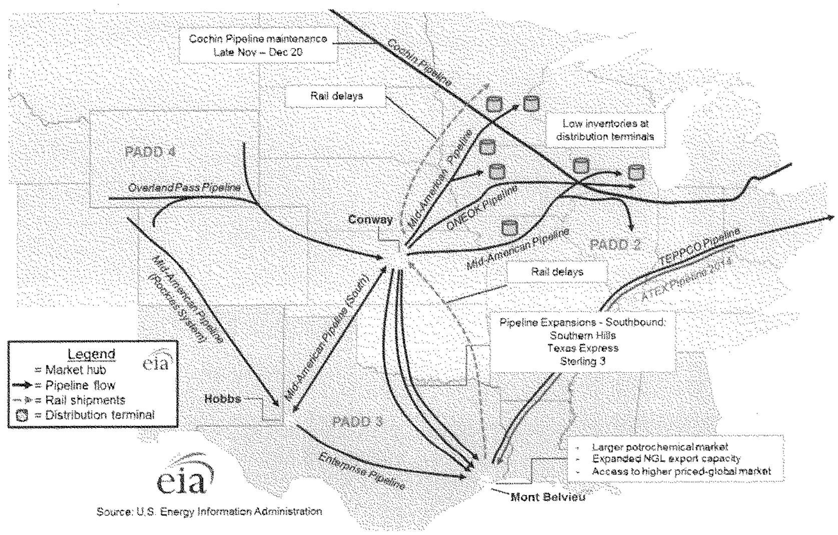
Source: EIA, Weekly Petroleum Status Report, data through February 28

As noted above, Conway, Kansas and Mont Belvieu, Texas are the major propane hubs serving the Midwest and Gulf Coast, respectively. Under market conditions that prevailed from March 2010 to Nov 2013, prices at Mont Belvieu were generally above those at Conway, providing a signal for supplies to move towards the Gulf Coast. Pipelines linking Conway and Mont Belvieu, are set up to carry supplies from north to south – their long-standing orientation. Rail is the primary mode available to carry propane northward from Mont Belvieu to Conway, because there is limited pipeline capacity to move propane south to north from Texas and New Mexico to Kansas.

The development of extreme propane shortages in the Midwest in mid-January, and a significant rise in prices at Conway relative to those at Mont Belvieu, provided a strong incentive for flows of propane from south to north. Those flows, which occurred within the constraints of available infrastructure, resulted in a significant reallocation of supplies, as evident in PADD-level weekly inventory data. The spike in U.S. propane prices also led to increases in imports into Minnesota and Michigan via pipeline connections from Canada, and additional tanker cargoes imported into Northeast ports.

At the beginning of December, spot wholesale prices that are reported daily by Reuters were nearly equal at the trading hubs at Conway and Mont Belvieu, both near $1.20 per gallon. By the beginning of January, Conway was about 18 cents per gallon higher than Mont Belvieu ($1.43 versus $1.25). During January, the price spread peaked at $2.96 per gallon on January 23, with several smaller peaks through the rest of the month. In February, the price spread diminished and as of March 4 prices per gallon are roughly equal at $1.11 at Conway and $1.10 at Mont Belvieu.

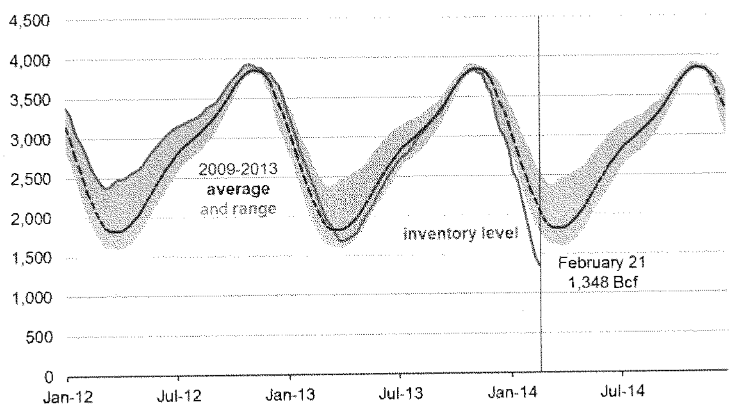
The continuing development of U.S. hydrocarbon resources, resulting in the increasing supply of crude oil, natural gas, and propane and other natural gas liquids will continue to present both challenges and opportunities for the use of existing infrastructure and the development of additional infrastructure in the future.



Natural Gas

Colder-than-normal weather, storage and pipeline constraints, and freeze-offs are key factors that have contributed to particularly high spot natural gas prices in the Midwest, Mid-Atlantic, and Northeast this winter. In areas that rely heavily on natural gas as a fuel for power generation, spot market prices for day-ahead, on-peak, electric power prices also rose to atypically high levels. However, in contrast to markets for propane and heating oil, where wholesale price movements are quickly reflected in retail prices, the retail electricity and gas rates paid by consumers who receive service through their local distribution utilities do not immediately reflect price spikes in the spot market.

Cold weather contributed to a new record-high withdrawal of natural gas from storage and a surge in natural gas spot prices. (Today in Energy, January 17, 2014, Attached as Exhibit C.) Natural gas working inventories on February 21 totaled 1,350 billion cubic feet (Bcf), 910 Bcf below the level at the same time a year ago, 710 Bcf below the previous five-year average (2009-13), and 450 Bcf below the previous five-year minimum. Henry Hub natural gas spot prices increased from $4.32 per million British thermal units (MMBtu) on January 2 to $8.15/MMBtu on February 10. The Henry Hub spot price was $4.81/MMBtu on February 26.

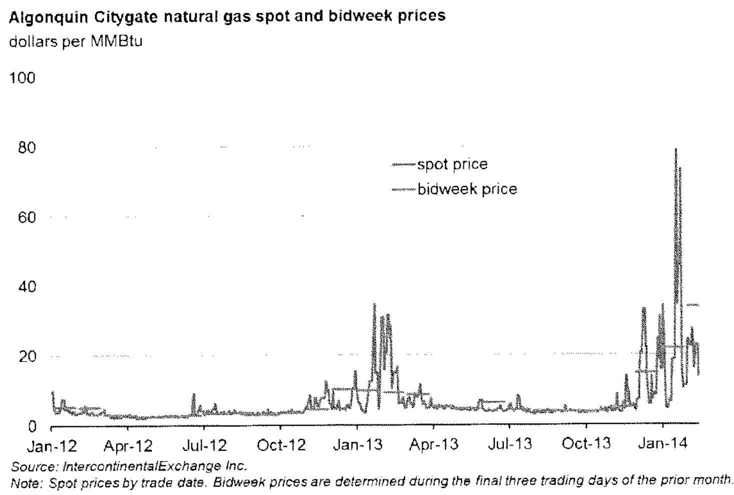


Source: Weekly Natural Gas Storage Report, data through February 21

New England faces some of the highest and most volatile spot natural gas prices. This volatility reflects both pipeline capacity constraints and significant growth in demand for natural gas, particularly for electricity generation, in the region. Reductions in imports of liquefied natural gas (LNG) and Canadian pipeline gas this winter added to the strain on pipelines serving New England that carry domestically–sourced natural gas.

New England spot natural gas prices hit record levels this winter. From January 1 to February 18, the day-ahead wholesale (spot) natural gas price at the Algonquin Citygate hub serving Boston averaged $22.53 per million British thermal units (MMBtu), according to data from Intercontinental Exchange (ICE). This price is a record high for these dates since the ICE data series began in 2001, and 50% above the same period in 2013, when cold weather drove New

England prices to their highest level since 2004.



(From Today in Energy, February 21, 2014)

The challenges faced by natural gas markets in New England are not new. New England spot natural gas prices in the winter of 2012-13 were also higher on average and more volatile than elsewhere in the United States. EIA released a supplement to the Short Term Energy Outlook in January of 2013. (Attached as Exhibit D.) Yet, in contrast to New York and the Middle Atlantic states, as this winter began there were no pipeline expansions underway to relieve capacity constraints that have been affecting the region for some time.*

* Despite increased natural gas production in the Marcellus supply basin and the addition of new pipeline capacity, the Mid-Atlantic region and the New York metropolitan area also faced supply constraints and very high spot market prices during the coldest days this winter.

The February 7, 2014, *Issues and Trends* (attached as Exhibit E) report on natural gas in New England discussed a number of potential ways to lessen the impact of limited peak natural gas supply at peak demand times, including pipeline expansions, additional fuel substitution by electric generators and other gas customers, and demand curtailment. Higher electricity imports from Canada, which could reduce reliance on within-region natural gas generation to serve electricity load, are another potential option.

Thank you for the opportunity to testify before the Committee.

Exhibit A

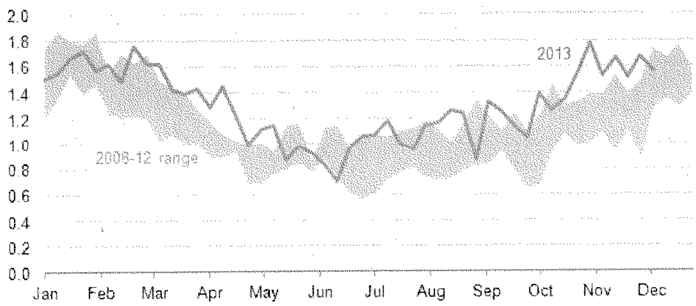
eia U.S. Energy Information Administration

Today in Energy

December 12, 2013

Propane demand hits a record high for November

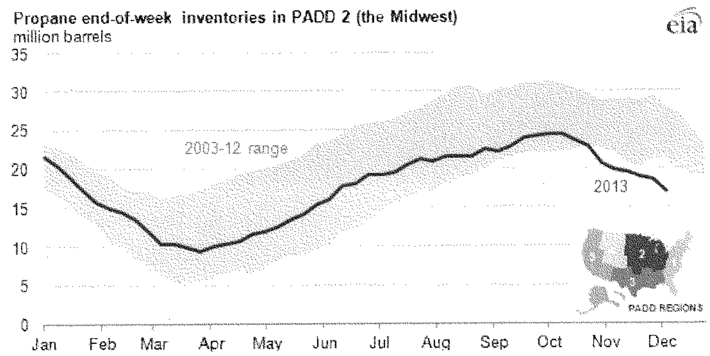
Propane product supplied
million barrels per day



Source: U.S. Energy Information Administration, Weekly Petroleum Status Report
Note: Product supplied is a proxy for consumption.
Republished December 12, 2013, 11:55 a.m. text was modified to clarify content and propane inventories graph was updated.

Propane is produced from natural gas at processing plants and from crude oil at refineries. Propane produced from natural gas has been the fastest-growing component of overall U.S. propane supply. Propane production in the United States has set record highs on an almost weekly basis in 2013 as a result of increased oil and natural gas drilling. A record corn crop harvest has increased the demand for propane (shown in the graph above as product supplied) in the central United States. Expanded propane production met this agricultural demand, while continuing to supply other markets.

A record-setting corn harvest is currently underway in the United States. According to the U.S. Department of Agriculture, corn production is forecast to be a record 14.9 million bushels in 2013-14. Corn must be dried to a 15% moisture content before it can be stored to avoid mold and other quality problems. Because propane is used for crop drying, a wet growing season in the Midwest combined with the largest corn yield in U.S. history has greatly increased the demand for propane. Thus far, Indiana, Iowa, Minnesota, Montana, Nebraska, South Dakota, and Wisconsin have declared states of emergency to allow for more delivery of propane throughout the Midwest.



Source: U.S. Energy Information Administration, Weekly Petroleum Status Report
Note: Ending inventories measured at the end of the reporting period.

According to EIA weekly data, demand for propane is currently at the highest level ever recorded for November. For the week ending November 1, the United States consumed nearly 1.8 million barrels per day—a figure typically not seen until January or February, when the winter heating season reaches a peak. As a result, propane inventories in PADD 2 (the Midwest) have fallen to their lowest level for November since 1996. Along with spiking domestic demand, competitively-priced U.S. propane exports have also surged. Exports from the United States are currently estimated to be 288,000 barrels per day, not far from the record of 308,000 barrels per day set in May 2013.

This boost in propane demand has created a spike in propane prices across the country. The winter heating season is just beginning to affect consumption figures, so propane demand for the 2013-14 season could continue at a record pace into the spring.

Principal contributor: Alex Wood

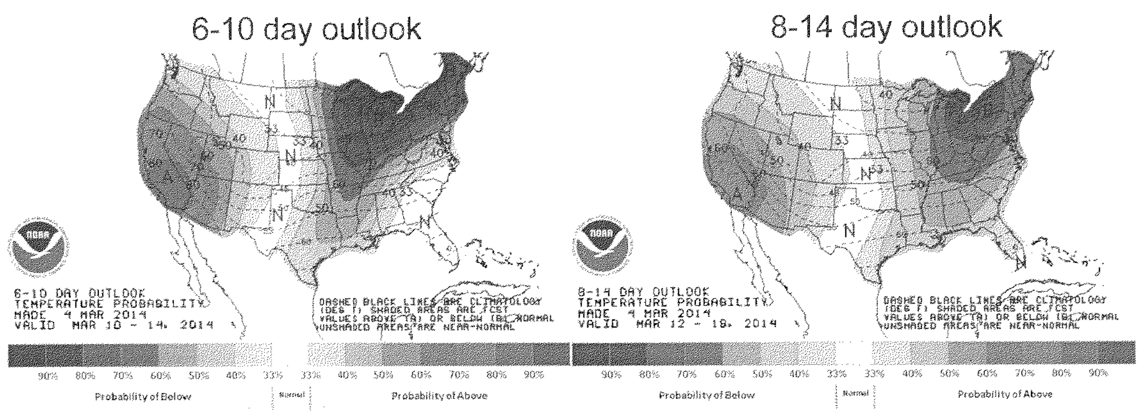
Exhibit B

Propane situation update

March 5, 2014 | Washington, DC

By
Energy Information Administration

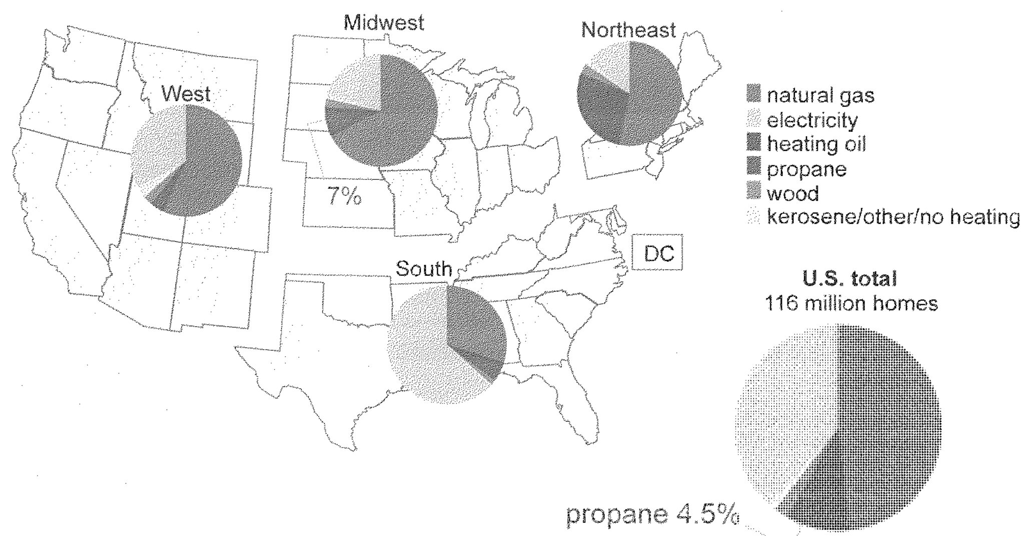
NOAA forecast shows below normal temperatures across most of the Midwest for March 10 through March 18



Source: National Oceanic and Atmospheric Administration Climate Prediction Center, made March 4

Natural gas and electricity are the major heating fuels for most of the United States

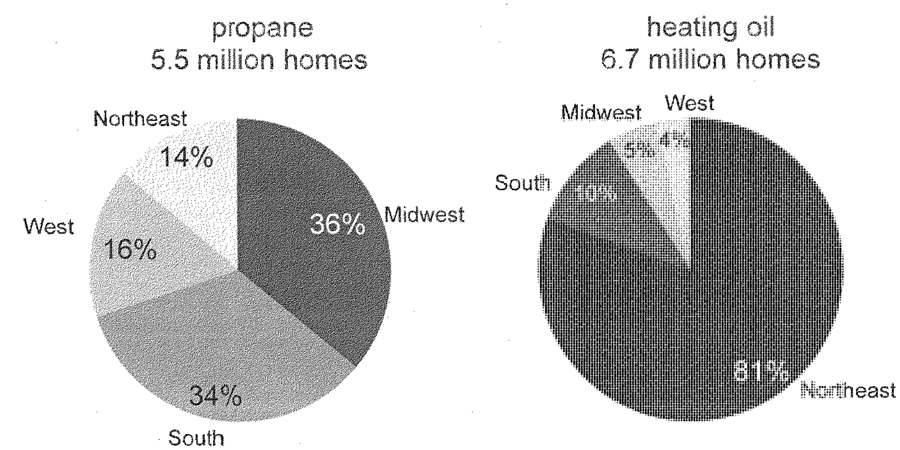
Share of homes by primary space heating fuel within each Census Region
(fuels add to 100%)



Source: U.S. Census Bureau, 2012 American Community Survey

Of all homes heated by propane, 36% are in the Midwest

Location of homes by primary space heating fuel across Census Regions
(regions add to 100%)

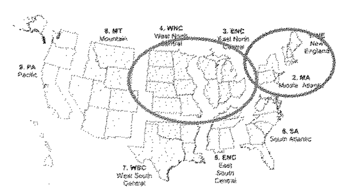


Source: U.S. Census Bureau, 2012 American Community Survey

Propane share of space heating demand by key regions and states

State	Propane-Heated Homes	Share of Total Homes
Michigan	320,522	8%
Wisconsin	245,071	11%
Ohio	240,185	5%
Minnesota	213,359	10%
Missouri	212,317	9%
Illinois	189,025	4%
Indiana	176,520	7%
Iowa	162,117	13%
Kentucky	113,175	7%
Tennessee	110,486	4%
Oklahoma	103,017	7%
Kansas	83,386	7%
Nebraska	57,442	8%
South Dakota	54,015	17%
North Dakota	38,617	13%
Midwest Total	**2,319,254**	**7%**

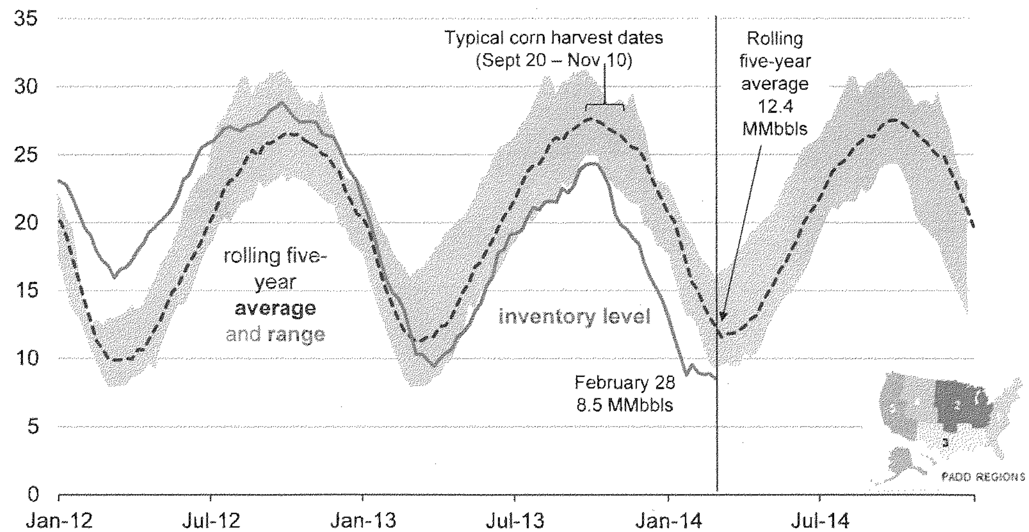
State	Propane-Heated Homes	Share of Total Homes
New York	237,738	3%
Pennsylvania	188,880	4%
New Hampshire	72,091	14%
Massachusetts	68,517	3%
New Jersey	60,990	2%
Connecticut	43,849	3%
Maine	41,477	7%
Vermont	38,497	15%
Rhode Island	10,351	3%
Northeast Total	**762,400**	**4%**



Source: Census Bureau, 2011

PADD 2 (Midwest) propane inventories have trended lower on strong crop drying and extremely cold temperatures

PADD 2 propane inventories
million barrels

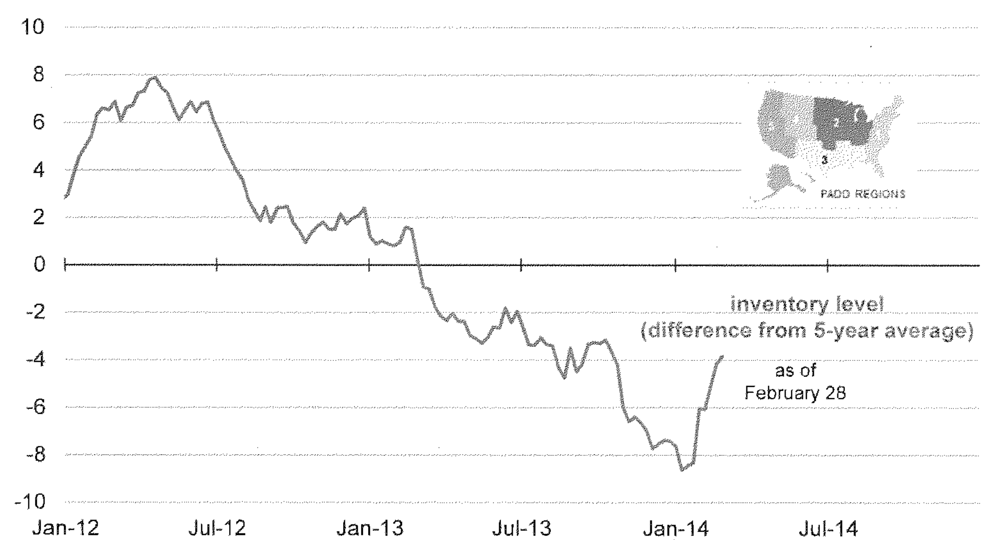


Source: EIA, Weekly Petroleum Status Report, data through February 28

PADD 2 (Midwest) propane inventories remain below the 5-year average, but gap is narrowing

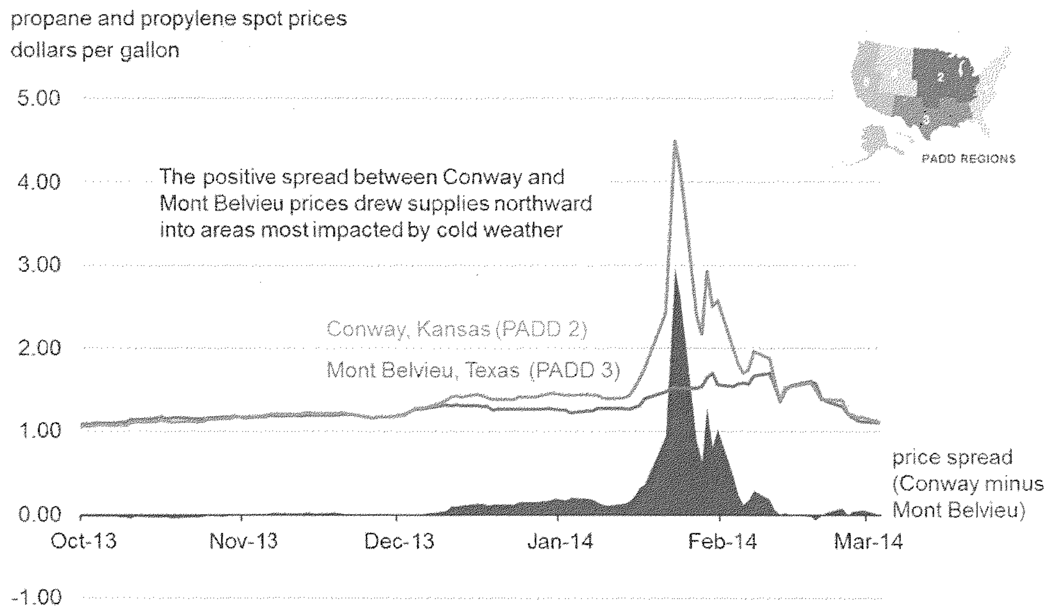
PADD 2 propane inventories, difference from 5-year average

million barrels



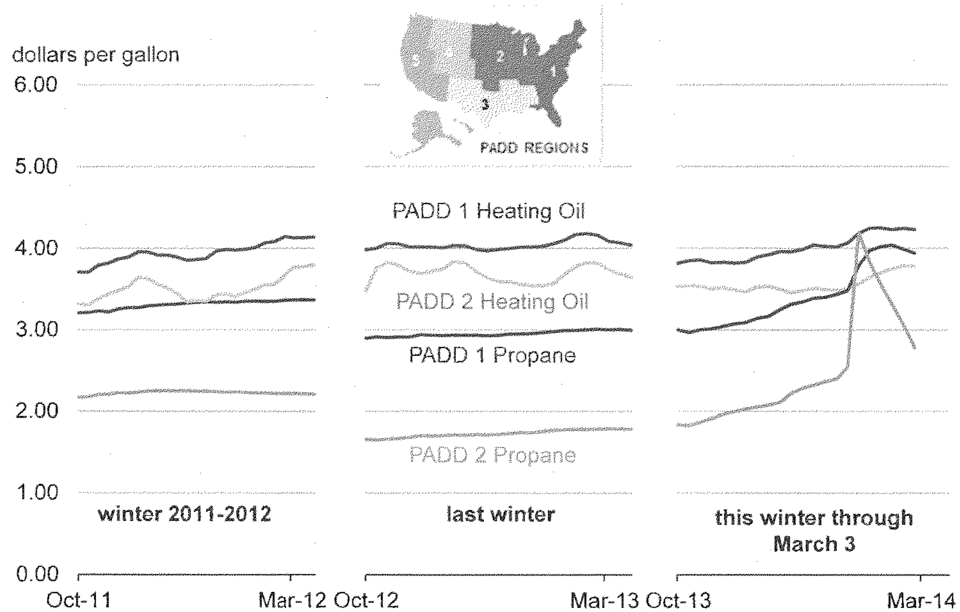
Source: EIA, Weekly Petroleum Status Report, data through February 28

Conway (KS) price premium over Mt. Belvieu (TX) grew rapidly in late January, but has since narrowed



Source: U.S. Energy Information Administration, Thomson Reuters, data through March 3

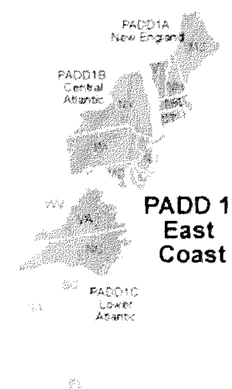
Retail propane prices in the Midwest, which rose sharply in late January, have moved lower



Source:State Heating Oil and Propane Program, data through March 3

State-reported residential retail prices for states in the East Coast

	1/20/14	1/27/14	2/3/14	2/10/14	2/17/14	2/24/14	3/3/14
Residential retail propane price (dollars per gallon, excluding taxes)							
Connecticut	3.528	3.653	3.792	3.918	3.870	3.902	3.902
Delaware	3.422	3.734	3.823	3.790	3.927	3.911	3.910
Maine	3.302	3.469	3.558	3.607	3.669	3.637	3.624
Maryland	3.603	3.865	3.956	4.055	4.134	4.144	4.125
Massachusetts	3.552	3.695	3.816	3.794	3.925	3.974	3.992
New Hampshire	3.539	3.672	3.706	3.728	3.835	3.827	3.835
New Jersey	3.984	4.235	4.451	4.433	4.460	4.436	4.431
New York	3.525	3.797	3.961	4.004	4.042	4.060	4.053
North Carolina	3.221	3.711	4.067	4.153	3.995	3.779	3.614
Pennsylvania	3.415	3.755	3.904	3.991	4.032	4.010	3.962
Rhode Island	4.037	4.207	4.399	4.456	4.538	4.615	4.660
Vermont	3.798	4.037	4.210	4.134	4.362	4.361	4.351
Virginia	3.378	3.753	4.039	4.069	4.066	3.915	3.818



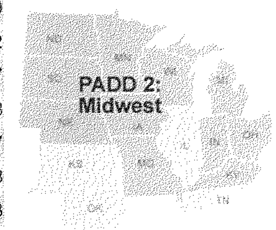
Note: Florida, Georgia, South Carolina, West Virginia, and the District of Columbia do not report information

Source: EIA, State Heating Oil and Propane Program, data through March 3

http://www.eia.gov/petroleum/heatingoilpropane/

State-reported residential retail prices for states in the Midwest

	1/20/14	1/27/14	2/3/14	2/10/14	2/17/14	2/24/14	3/3/14
Residential retail propane price (dollars per gallon, excluding taxes)							
Indiana	2.939	4.215	4.265	4.043	3.753	3.472	3.248
Iowa	2.584	4.709	3.590	3.220	2.811	2.591	2.149
Kentucky	2.577	3.785	3.852	3.677	3.584	3.417	2.942
Michigan	2.638	3.611	3.766	3.620	3.692	3.359	3.247
Minnesota	2.439	4.610	3.967	3.471	3.264	2.985	2.658
Missouri	2.433	3.997	3.672	3.484	3.131	2.960	2.657
Nebraska	2.005	4.073	3.357	2.995	2.601	2.393	2.048
North Dakota	2.322	4.569	3.839	3.283	2.905	2.651	2.333
Ohio	2.999	3.731	3.908	3.755	3.733	3.615	3.489
South Dakota	2.088	4.107	3.664	3.408	3.019	2.797	2.751
Wisconsin	2.276	4.490	3.945	3.686	3.344	2.967	2.650

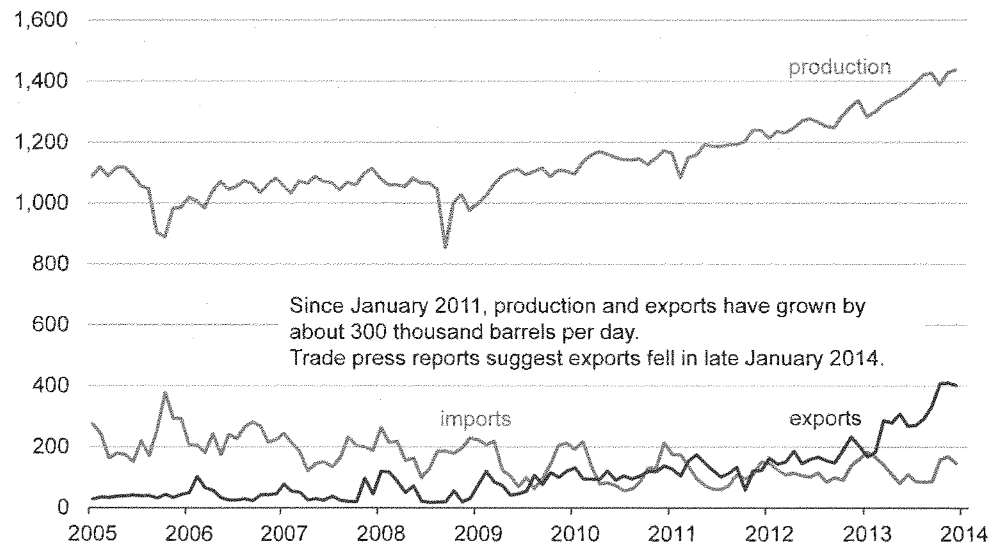


Note: Illinois, Kansas, Oklahoma, and Tennessee do not report information
Source: EIA, State Heating Oil and Propane Program, data through March 3
http://www.eia.gov/petroleum/heatingoilpropane/

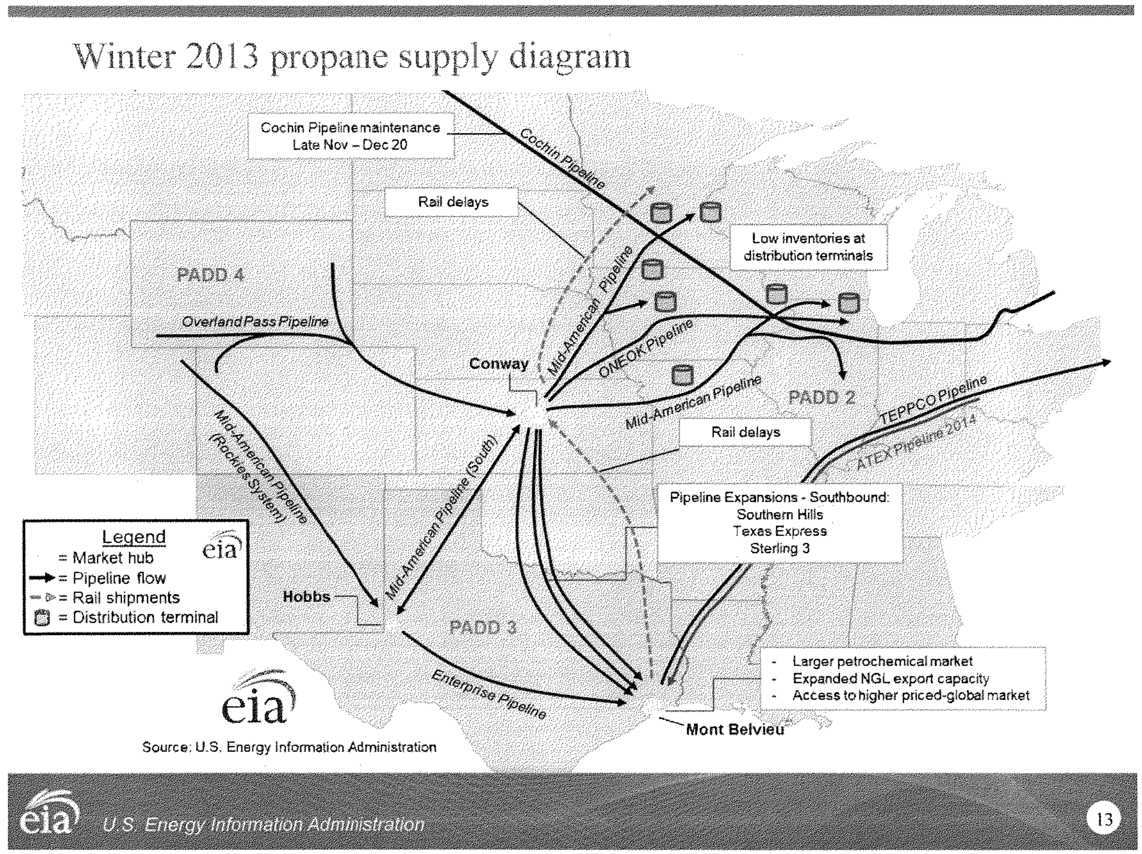
U.S. propane production and trade trends

U.S. propane and propylene production, imports, and exports

thousand barrels per day



Source: EIA, Petroleum Supply Monthly through December 2013


Winter 2013 propane supply diagram
Cochin Pipeline maintenance
Late Nov – Dec 20
Cochin Pipeline
Rail delays
Low inventories at
distribution terminals
PADD 4
Overland Pass Pipeline
Conway
Mid-American Pipeline
ONEOK Pipeline
Mid-American Pipeline
PADD 2
TEPPCO Pipeline
ATEX Pipeline 2014
Rail delays
Mid-American Pipeline
(Rockies System)
Mid-American Pipeline (South)
Pipeline Expansions - Southbound:
Southern Hills
Texas Express
Sterling 3
Legend
= Market hub
= Pipeline flow
= Rail shipments
= Distribution terminal
Hobbs
PADD 3
Enterprise Pipeline
- Larger petrochemical market
- Expanded NGL export capacity
- Access to higher priced-global market
Mont Belvieu
Source: U.S. Energy Information Administration
U.S. Energy Information Administration
13

For more information

U.S. Energy Information Administration home page | www.eia.gov

Short-Term Energy Outlook | www.eia.gov/steo

Annual Energy Outlook | www.eia.gov/aeo

International Energy Outlook | www.eia.gov/ieo

Monthly Energy Review | www.eia.gov/mer

Today in Energy | www.eia.gov/todayinenergy

State Energy Portal | www.eia.gov/state

Drilling Productivity Report | www.eia.gov/petroleum/drilling

Exhibit C

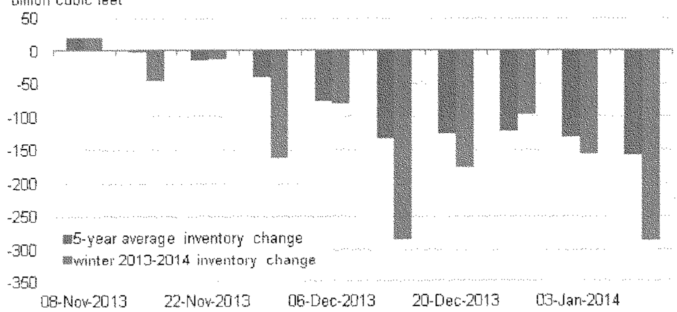
eia U.S. Energy Information Administration

Today in Energy

January 17, 2014

Cold weather led to record-high natural gas storage withdrawals

Winter 2013-14 and 5-year average net storage withdrawals
billion cubic feet



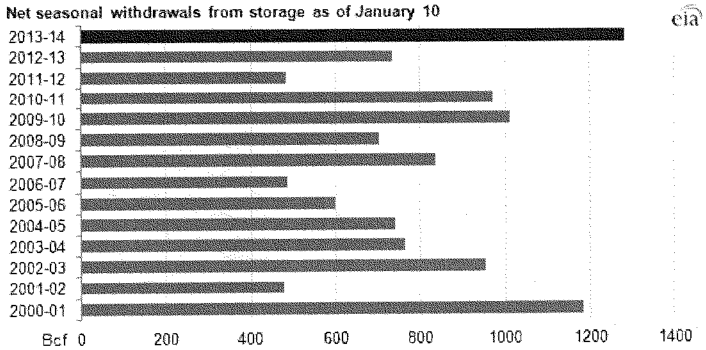
Source: U.S. Energy Information Administration, Weekly Natural Gas Storage Report

Last week's widespread, record-breaking cold weather had significant effects across virtually all segments of the U.S. natural gas market. The frigid temperatures led to record highs in demand, storage withdrawals, and prices.

The week ending January 10 posted a record-high net withdrawal of 287 billion cubic feet (Bcf) from underground, natural gas storage facilities. The January 10 withdrawal is the largest for the 20 years for which data exist and the latest in a season already characterized by withdrawals much larger than average. This week's storage withdrawal was the second record-breaking weekly stock draw this season; the withdrawal of 285 Bcf for the week ending December 13 exceeded the previous record of 274 Bcf from January 2008. Cumulative net withdrawals, as of January 10, 2014, exceeded the previous record levels posted during the 2000-2001 heating season. Bentek Energy estimated stock draws hit 57.1 Bcf on January 6, and then 67.9 Bcf the following day. The next-highest draw was 52.9 in February 2011.

High storage withdrawals were expected to meet surging demand for heating from the residential, commercial, and electric power sectors, with analyst estimates, as published by Bloomberg, ranging between 278 and 321 Bcf. The cold weather also impacted natural gas production. Freeze-offs occurred in the parts of the Marcellus Shale in northeastern Pennsylvania and in the Fayetteville Shale in Arkansas, according to Bentek Energy. Dry natural gas production dropped to 61.9 Bcf on January 8, the lowest level since September 2012, and has been gradually increasing since then, reaching nearly 66 Bcf as of January 16.

Net seasonal withdrawals from storage as of January 10



Source: U.S. Energy Information Administration, Weekly Natural Gas Storage Report
Note: Data above reflect withdrawals between October 31 and January 10. 2008-13 average = 780 Bcf.

In the Northeast, where more than half of homes use natural gas as their primary space-heating fuel, several pipelines issued critical notices and operational flow orders (OFOs) to prevent system imbalances. Additionally, Texas Eastern Pipeline, a major interstate pipeline supplying the Northeast, issued a force majeure (which frees both parties from upholding contractual obligations in the event of extraordinary circumstances) following unplanned maintenance at a compressor station in Pennsylvania.

Natural gas prices in the Northeast spiked to between $30 and $40 higher than the benchmark Henry Hub price. On the Transcontinental Pipeline's Zone 5 line, which serves Mid-Atlantic customers, prices reached $72.43/MMBtu on Monday. Prices in New York and New England also rose far into the double digits, with Transco's Zone 6 delivery point, serving New York City, at $56.59/MMBtu, and the Algonquin Citygate, serving Boston, at $34.14/MMBtu.

The extreme cold temperatures that affected Northeast natural gas markets during the first half of last week arrived earlier in the Midwest, where about 68% of households use natural gas for heating. While it is common for prices to spike in the Northeast during times of high demand, Midwest prices are normally close to Henry Hub prices, as the region does not typically have major supply bottlenecks. Prices at the Chicago Citygate rose to levels almost $10/MMBtu greater than Henry Hub prices on Friday, January 3, as temperatures in the Midwest dipped to levels that prompted the Chicago Zoo to bring its polar bear indoors. Both ANR Pipeline and NGPL, major interstate pipelines that send natural gas to the Midwest, issued OFOs, and many other pipelines in the region issued critical notices that curtailed normal gas-flow scheduling to maintain balance on their systems.

Principal contributor: Katherine Teller

Exhibit D

Independent Statistics & Analysis
U.S. Energy Information Administration

January 18, 2013

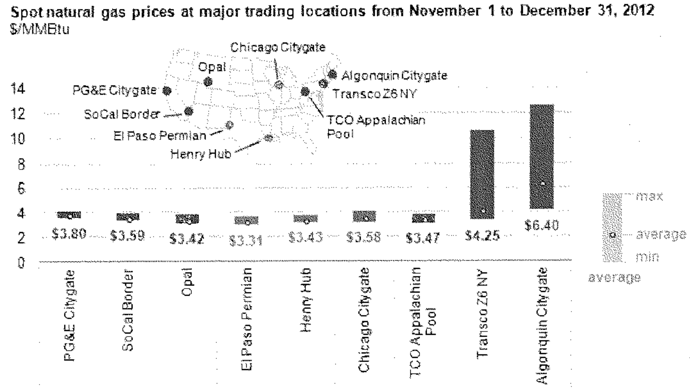
Short-Term Energy Outlook Supplement: Constraints in New England likely to affect regional energy prices this winter

Since November, New England has had the highest average spot natural gas prices in the nation. Average prices at the Algonquin Citygate trading point, a widely used index for New England natural gas buyers, have been $3 per million British thermal units (MMBtu) higher than natural gas prices at the Henry Hub, and more than $2 per MMBtu higher than average spot price at Transco Zone 6 NY, which serves New York City and has historically traded at prices similar to those in New England (see Figure 1).

Full pipelines from the west and south limit further deliveries from most of North America, while high international prices and declining production in eastern Canada pose challenges in making up the difference from the north and east, except at higher prices.

As a result of these market conditions, New England natural gas and electric power prices this winter could be volatile at times. During November and December, spot natural prices in the northeastern United States seesawed in relation to weather-driven pipeline constraints. This price volatility has continued into January 2013 to date.

Figure 1. Spot natural gas prices at major trading locations

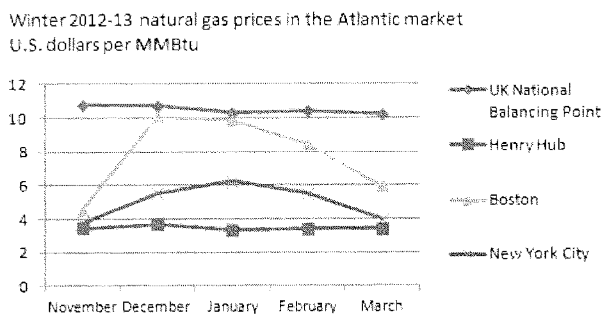


Source: U.S. Energy Information Administration based on Ventyx, Energy Velocity Suite.

However, spot natural gas prices in New England so far this winter have still been less expensive than those in northwestern Europe, meaning that it continues to be more attractive to deliver a spot (or unscheduled) cargo of liquefied natural gas (LNG) to Europe than to New England.

Looking to the rest of this winter, recent forward market prices indicate that New England's high natural gas prices could persist and rival northwestern European prices, especially this month (see Figure 2). In that case, New England may receive spot cargos of LNG.

Figure 2. Forward prices of natural gas in the United States and United Kingdom



Source: U.S. Energy Information Administration based on Bloomberg, L.P.

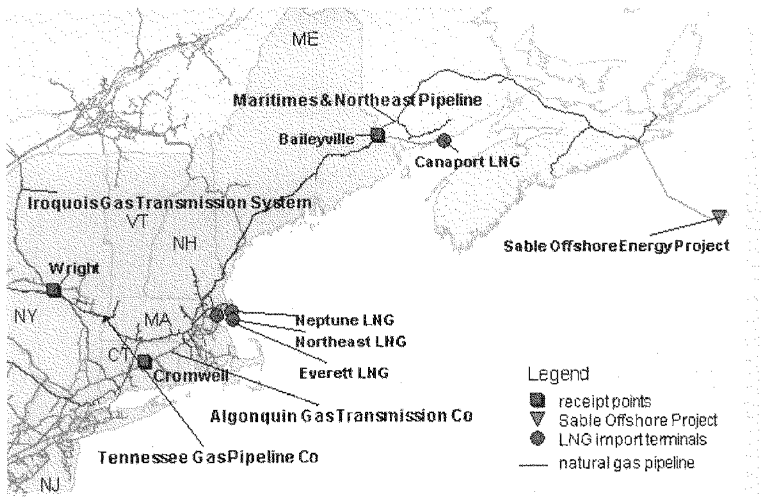
Note: Forward values reflect market closes on December 27, 2012, for the January, February, and March futures contracts. The November and December forward values reflect the settlement prices as of the dates the New York Mercantile Exchange (NYMEX) natural gas futures contracts expired, or settlement prices on October 29, 2012 (for November), and November 28, 2012 (for December).

Forward prices reflect monthly values. In the Northeast, forward natural gas prices in the winter typically reflect expectations that for some days, weather-driven constraints may lead to very high prices, while other days may see more moderate weather and prices. For example, a natural gas basis swap (which reflects the difference in effective price between a given point and the reference pricing point of Henry Hub) for the month of January covers 31 days. A forward basis swap valued at $6 per MMBtu could underpin an assumption of 20 days, with average prices of $4.35 per MMBtu and 11 days with prices averaging more than double that, or about $9 per MMBtu.

Why are prices at the Algonquin Citygate trading point so high? Several factors act simultaneously to constrain natural gas deliveries into New England, and therefore raise regional prices:

- Natural gas from the west and south is flowing at or near the capacities of existing pipelines
- LNG shipments into the Boston area and New Brunswick, Canada declined in 2012 because global market conditions have directed shipments elsewhere, and because of supply disruptions in Yemen
- Natural gas wellhead production from the Sable Offshore Energy Project (SOEP) in Nova Scotia has declined to a small fraction of its levels in previous years

Figure 3. New England natural gas infrastructure overview map

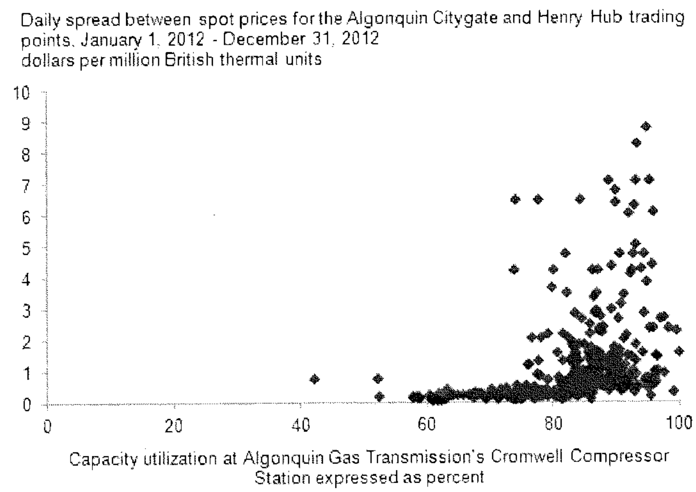


Source: U.S. Energy Information Administration based on Ventyx's Energy Velocity Suite.

Pipeline Constraints. Key natural gas pipelines from supply areas to New England are full or nearly full. The Algonquin Gas Transmission (Algonquin) system and the Tennessee Gas Pipeline (TGP) transport most of the natural gas into the New England market. Recently, both of these systems have been constrained.

Algonquin has run at high utilization (load factors calculated as average daily natural gas flows divided by peak use) since mid-2012. The Cromwell Compressor Station, a key throughput point on the Algonquin system (near Hartford, Connecticut), with a peak-day capacity of almost 1 billion cubic feet per day (Bcf/d), averaged about 86% utilization between November 1, 2012 and December 31, 2012. As a rule, when pipeline utilization at Cromwell exceeds 85%-90%, the constraint tends to bind and the spread between the Algonquin Citygate price and the Henry Hub price begins to rise (see Figure 4).

Figure 4. Daily natural gas basis (spread) between the Henry Hub and the Algonquin Citygate versus capacity utilization at Cromwell Compressor Station for 2012



Source: U.S. Energy Information Administration based on the Ventyx Energy Velocity Suite.

Note: The spread reflects the daily difference between the spot prices of natural gas at the Algonquin Citygate and Henry Hub trading points.

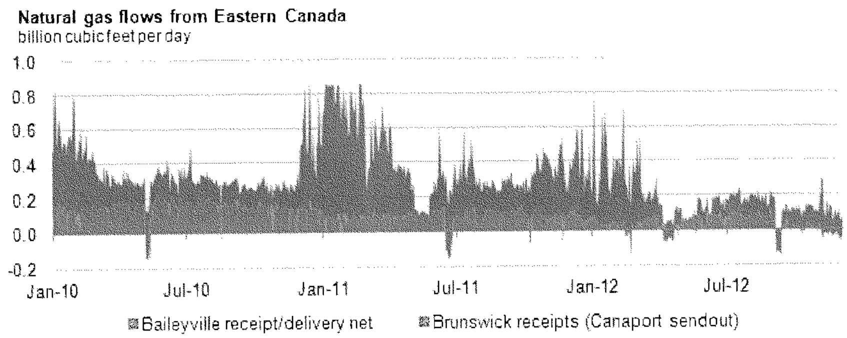
Algonquin throughput is up for the last year because:

- It serves as an outlet for growing natural gas production levels in the Marcellus basin; Bentek Energy estimates that about two-thirds of the gas flowing through the Cromwell Compressor Station comes from the Marcellus Basin and the remainder likely comes from the Gulf Coast
- Algonquin throughput is substituting for declines in other sources (regional LNG deliveries and SOEP production)
- Demand for natural gas has remained strong in New England, even during the summer

Natural gas flows on the Tennessee Gas Pipeline system into New England have also been high this winter.

Declining Supplies in Eastern Canada. Contributions of eastern Canadian natural gas production to New England's gas supply have been falling. Figure 5 below shows natural gas flows on the Maritimes and Northeast Pipeline between Canada and the United States. There are two principal sources of natural gas in eastern Canada that can be delivered into the United States at the Baileyville interconnect: production from the Sable Offshore Energy Project and send-out from the Canaport LNG terminal in St. John, New Brunswick. Both sources of potential supply have been limited so far this winter.

Figure 5. Natural gas flows between eastern Canada and the United States

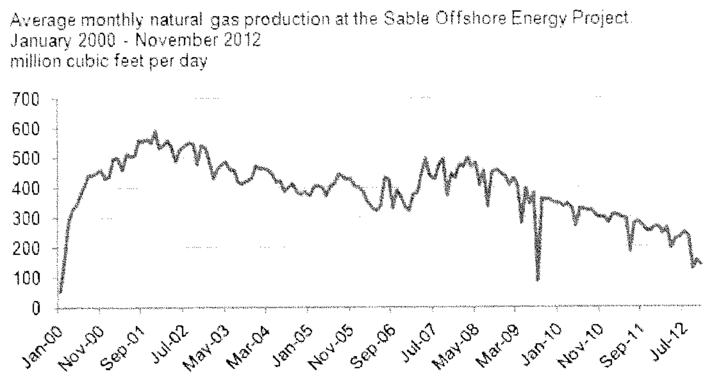


Source: U.S. Energy Information Administration based on Bentek Energy LLC.

Note: Baileyville is an interconnect between the Maritimes and Northeast Pipeline (Canada) and Maritimes and Northeast Pipeline (U.S.). Shippers on Maritimes and Northeast Pipeline can schedule to receive or deliver natural gas at this point. When natural gas deliveries at Baileyville exceed receipts, on a net basis, the customers on the Maritimes and Northeast system are effectively exporting natural gas to eastern Canada.

Natural gas supplies from the Sable Offshore Energy Project (SOEP), in Eastern Canada to New England are down because of two main factors: (1) reduced production at the SOEP), and (2) repairs that reduce or halt gas flows from SOEP. Bentek Energy reports that only three of five producing fields at Sable Island are operating now because of required repairs to a subsea flow line. As a result, SOEP production may continue to be curtailed until spring 2013, when these repairs can be made. Based on data from the Canada-Nova Scotia Offshore Petroleum Board, SOEP production in October 2012 was down about 30% compared to average production for the first three-quarters of 2012. Moreover, Encana's Deep Panuke offshore natural gas project which could have offset some of SOEP's lost production, was slated to begin commercial operations in early 2013 but now has deferred start-up, possibly until mid-2013.

Figure 6. Average monthly natural gas production at the Sable Offshore Energy Project



Source: U.S. Energy Information Administration based on Canada-Nova Scotia Offshore Petroleum Board.

Note: Production figures reported on a dry natural gas equivalent basis.

Reduced liquefied natural gas imports. New England has historically depended on imports of LNG for several reasons:

- Lack of local area storage facilities
- High seasonal demand peaks—especially in the winter
- Lack of locally produced natural gas
- Remoteness from the rest of the North American natural gas grid

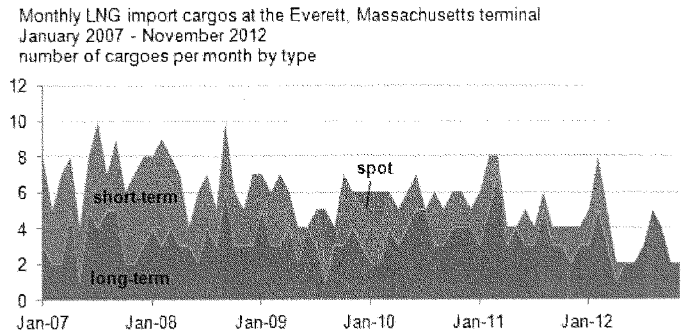
Since November 2010, LNG has supplied about 25% of New England's daily natural gas demand and, on a peak day, LNG in the winter has sometimes accounted for 60% of New England's total natural gas supply needs.

New England can receive LNG from four existing North Atlantic regasification terminals—three in the United States and one in Saint John, New Brunswick, in Canada. The U.S. terminals are the Everett, Massachusetts facility near Boston, now operated by GDF SUEZ Gas NA, and two offshore terminals—Neptune and Northeast Gateway. New England LNG is delivered in the following ways: by pipeline directly to customers; by truck to several dozen regional satellite storage tanks; and to an adjacent natural gas-fired electric generating plant, Exelon Corp.'s Mystic Generating Station in Charlestown, Massachusetts.

Everett Terminal

LNG imports at the Everett terminal have been declining. The Everett terminal has two storage tanks with a combined capacity of 3.4 billion cubic feet (Bcf), or only a little more than typical single-cargo deliveries. For most of 2012, Everett has only received LNG cargoes contracted on a long-term basis (see Figure 7). Short-term (contracts of up to two years) and spot cargoes have been diverted to other markets. Previously, Everett routinely received 6 to 10 cargoes per month, but through most of 2012 it got only 2 to 4 cargoes per month.

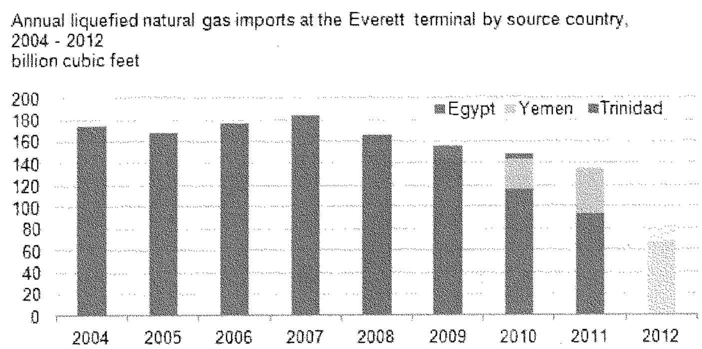
Figure 7. Monthly imports of liquefied natural gas at the Everett terminal



Source: U.S. Energy Information Administration based on the U.S. Department of Energy, Office of Fossil Energy. Data reported through November 2012.

Most of Everett's LNG comes from Trinidad and Tobago, but it is supplemented with supplies from elsewhere. Shipments from Yemen were down in 2012 because attacks on Yemeni pipeline infrastructure affected operations at the Balhaf liquefaction terminal on the Gulf of Aden. Everett's LNG imports have been declining since 2008; from 2004 to 2008, Everett's annual imports topped 160 Bcf each year.

Figure 8. Everett liquefied natural gas imports by country of origin



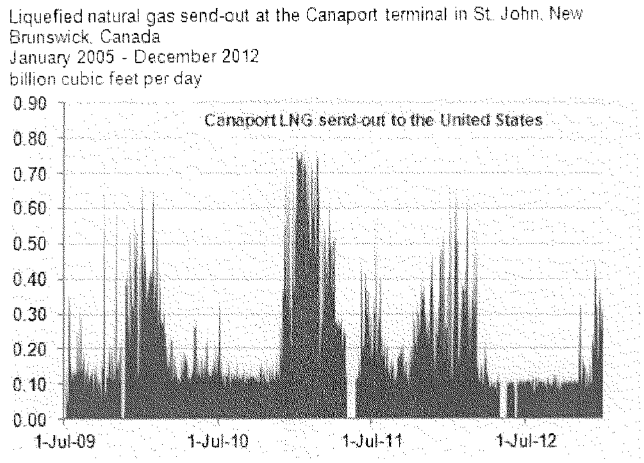
Source: U.S. Energy Information Administration based on the U.S. Department of Energy, Office of Fossil Energy.

Note: Data for 2012 reflect partial year figures from January through October.

Canaport Terminal

LNG imports at the Canaport terminal have been down throughout much of 2012. Since May 2012, Canaport deliveries to the United States averaged 100 million cubic feet per day MMcf/d; peak sendout at Canaport can top 700 MMcf/d.

Figure 9. Canaport LNG terminal deliveries to the Maritimes and Northeast Pipeline at the Brunswick Pipeline meter station



Source: U.S. Energy Information Administration based on Bentek Energy LLC.

Note: Canaport deliveries to the U.S. measured on Maritime and Northeast, Canada's Brunswick Pipeline meter station. Data reported for July 2009 through December 31, 2012.

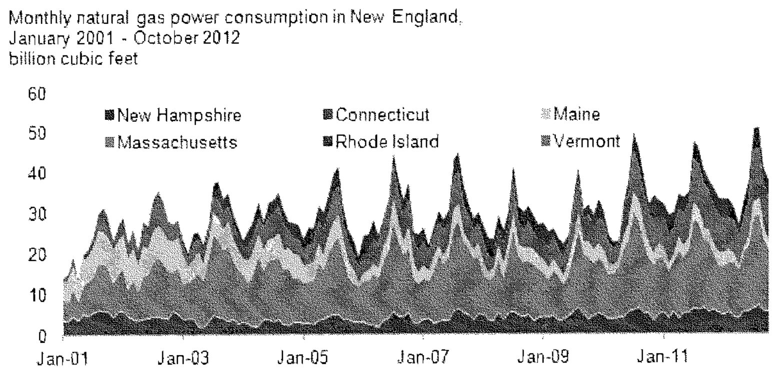
Offshore Terminals

Both offshore terminals receive LNG shipments only occasionally. The receipts are generally tied to market circumstances when both New England demand and natural gas prices are high. Lately, these terminals have received few cargoes because competing markets in western Europe (the United Kingdom, the Netherlands, Belgium, and Spain) or Asia (Korea, Japan, China, or India) typically offer higher prices—sometimes approaching $20 per MMBtu. Excelerate Energy's Northeast Gateway offshore terminal is located 13 miles off the coast of Massachusetts; it started commercial service in 2008 and has a sendout capacity of 0.6 Bcf/d. GDF SUEZ Gas NA's Neptune LNG LLC offshore terminal is located about 10 miles off the coast of Massachusetts; it began service in 2009 and has a sendout capacity of 0.4 Bcfd. Both of these LNG facilities have interconnections to the Algonquin's HubLine pipeline.

Rising demand. Natural gas demand in New England will likely be higher during the winter of 2012-13 compared with the winter of 2011-12 (one of the warmest winters in 60 years), and this could put upward pressure on natural gas and power prices in New England. On January 17, the National Oceanic and Atmospheric Administration (NOAA) released its 8-14 day temperature outlook calling for below-normal temperatures in the northeastern United States. By contrast, NOAA's three-month outlook, February through April, called for above-normal temperatures in the northeastern United States. Natural gas demand in eastern Canada this winter has already absorbed the more-limited Sable Island production that usually augments New England's natural gas supplies.

Natural gas use for power is rising in New England. Average natural gas use for power generation in New England was up about 3% from January to October in 2012, compared to the same period in 2011. Natural gas accounted for 51% of total generation in ISO New England in 2011.

Figure 10. Monthly natural gas use for power trends in New England



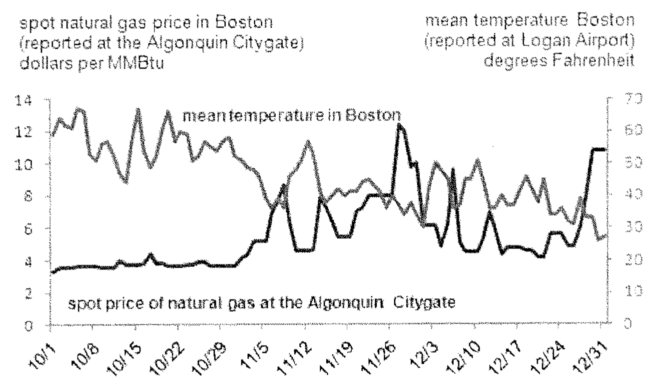
Source: U.S. Energy Information Administration, Natural Gas Monthly.

Note: New England states include Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. Monthly data reported for January 2001 – October 2012.

What are the ramifications of constrained supplies for New England?

As a result of these market conditions, New England natural gas and electric power prices this winter could be volatile at times. During November and December, prices seesawed in relation to weather-driven pipeline constraints.

Figure 11. Recent trends in spot natural gas prices and mean temperatures in Boston

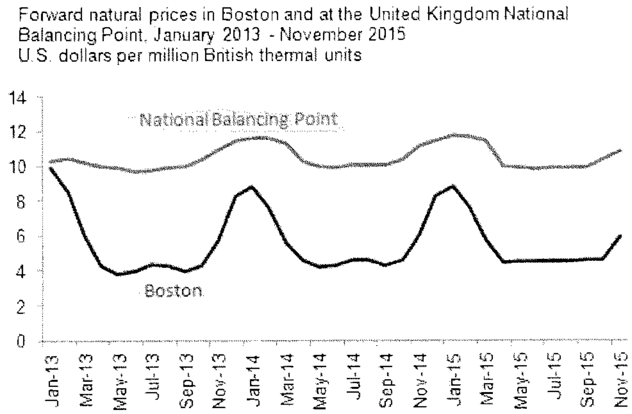


Source: U.S. Energy Information Administration based on Bloomberg, L.P.

Note: Daily temperatures reflect mean values recorded at Logan Airport in Boston, Massachusetts. Spot natural prices reported at the Algonquin Citygate.

These market conditions are affecting current, spot market prices as well as forward prices. Forward expectations for prices can be assessed by examining trends in natural gas basis swaps. Natural gas swaps for the Algonquin Citygate trading point have topped $6 per MMBtu for the peak winter months of January and February. Forward curves for natural gas in Boston and at the National Balancing Point (NBP) benchmark in the United Kingdom, as of December 27, 2012, show that although expectations for natural gas prices were somewhat comparable for January 2013, the NBP market reflected premiums compared to natural gas in Boston through 2015.

Figure 12. Forward natural gas prices in Boston and the United Kingdom



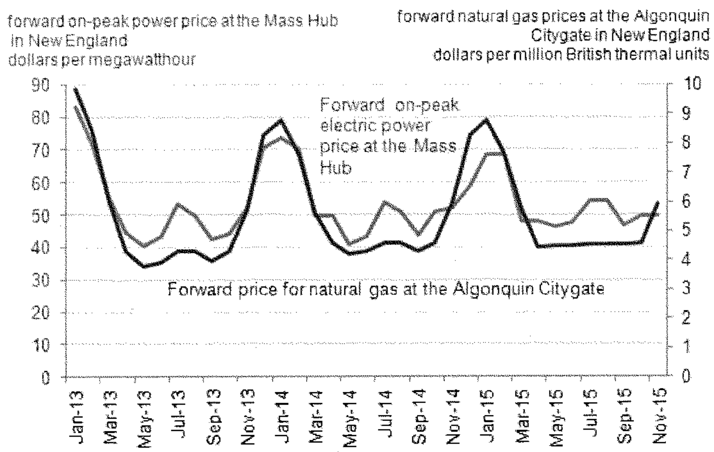
Source: U.S. Energy Information Administration based on Bloomberg, L.P.

Note: Forward curves reflect the futures contracts reported by the IntercontinentalExchange for the U.K. National Balancing Point and the NYMEX natural gas futures contract at Henry Hub plus a basis swap at the Algonquin Citygate trading point. A natural gas basis swap is a financial instrument reflecting market participants' future valuation of the difference in price between the Henry Hub natural gas futures contract for a given month and the price of gas in a downstream market location like Boston, Massachusetts, for the same, future month. Forward curves shown are based on settlement values as of December 27, 2012.

Because generators using natural gas often set the market-clearing price for electric power, wholesale electric power prices often trend together with natural gas prices. In these circumstances, natural gas is referred to as being the "fuel on the margin." As a result, higher spot natural gas prices may contribute to higher electric power prices. Natural gas is generally the fuel on the margin much of the time in New England.

The shape of the forward curve for natural gas in New England between January 2013 and November 2015, using the Algonquin Citygate price as a proxy, is fairly similar to the shape of the forward electricity curve at the Mass Hub—a proxy for the price of power in New England (see Figure 13). The chart indicates that there will be highly seasonal price patterns during the next three years with pronounced winter peaks.

Figure 13. Forward electric power and natural gas prices in New England



Source: U.S. Energy Information Administration based on Bloomberg, L.P.

Note: Forward curves reflect a Bloomberg-reported index for an over-the-counter forward price for electric power in New England at the Mass Hub expressed in dollars per megawatthour and the NYMEX natural gas futures contract at Henry Hub plus a financial basis swap at the Algonquin Citygate trading point expressed in dollars per MMBtu.

Exhibit E

Independent Statistics & Analysis
U.S. Energy Information Administration

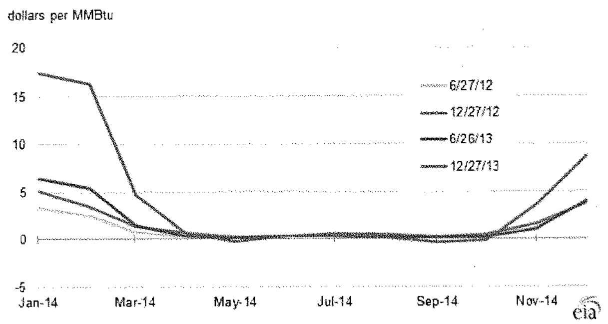
February 7, 2014

High Prices Show Stresses in New England Natural Gas Delivery System

Abstract. Since 2012, limited supply from the Canaport and Everett liquefied natural gas (LNG) terminals coupled with congestion on the Tennessee and Algonquin pipelines have led to winter natural gas price spikes in New England. The problem continued in the winter of 2013-14, as indicated by New England's forward basis for January 2014 reaching $17.41. Pipeline expansions could ease price spikes, but their cost-effectiveness, including their ultimate cost to consumers, remains a challenge. This article reviews possible alternatives. The data are presented in three summary tables and in detailed state tables.

During the past two winters, New England natural gas winter prices have risen significantly. The average bidweek natural gas price reached a high of $14.52 per million British thermal units (MMBtu) for December 2013 and more than $20/MMBtu for January 2014. The January New England forward basis[1], reflecting the relationship between market conditions at a specified regional hub and those at Louisiana's Henry Hub, settled at $17.41,[2] and the forward basis curves indicate a market expectation of a record-high winter basis (Figure 1). The high winter prices in New England suggest a natural gas delivery system that is stretched significantly.[3]

Figure 1. Forward basis curves for natural gas in New England



Source: U.S. Energy Information Administration, Bloomberg LP

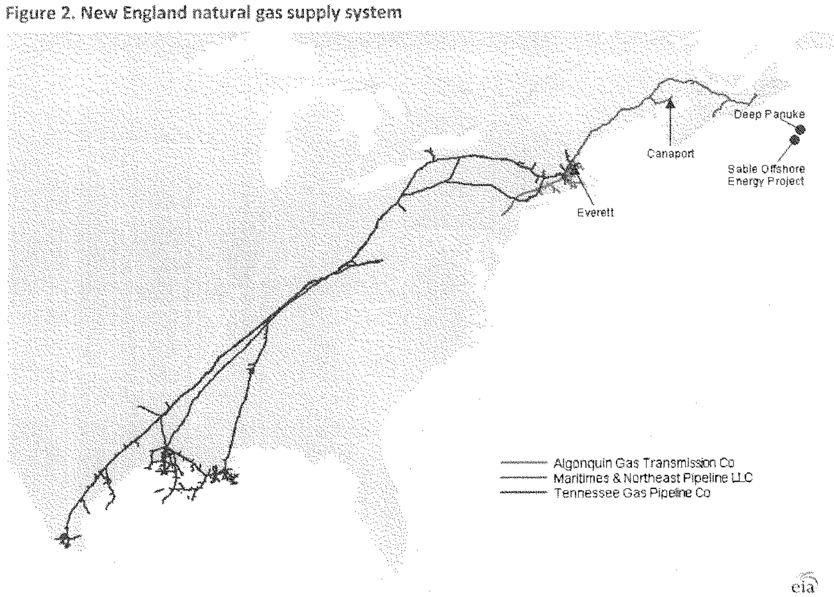
[1] In the natural gas industry, basis is the difference between a natural gas price at a given location and the benchmark Henry Hub (Louisiana) price; a forward price of a given forward month is a contract price for delivering a specified amount of natural gas in the given month. A forward basis of a given location is the difference between the forward prices at the given location and at Henry Hub. A spot price is a contract price for delivering natural gas on the next day. A spot basis at a given location is the difference between spot prices at the given location and Henry Hub.

[2] This specific basis was at the Algonquin Citygate.

[3] See also Constraints in New England likely to affect regional energy prices, Market Alerts, and the Market Prices and Uncertainty Report.

New England receives natural gas from several sources. Most natural gas delivered into New England flows through the Tennessee Gas Pipeline (TGP) and Algonquin Gas Transmission pipeline (AGT), both of which flow gas into the region from the south. Massachusetts's Everett liquefied natural gas (LNG) terminal also supplies natural gas to the region and is connected with the AGT and TGP pipelines.[4] Canada's Canaport LNG import terminal also sends natural gas into the region through the Maritimes & Northeast (M&N) pipeline, which has the option of delivering natural gas to New England from the production fields in the Sable Offshore Energy Project and Deep Panuke in Nova Scotia, Canada (Figure 2).

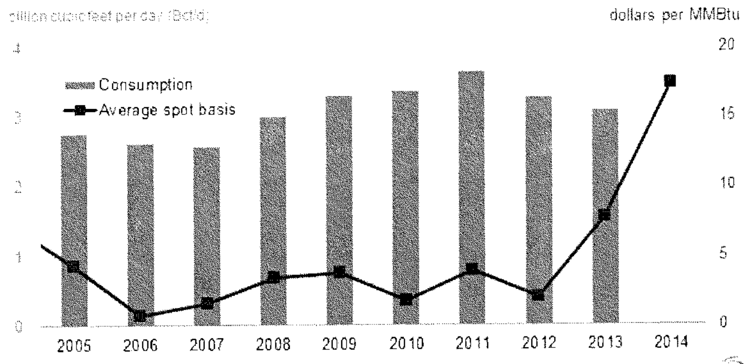
Figure 2. New England natural gas supply system



The TGP and AGT pipelines have a combined transport capacity of about 3.5 billion cubic feet (Bcf) per day delivered into New England, including gas from domestic production and storage withdrawal, Canadian production, and imported LNG. Although transport capacity is greater than average January consumption (Figure 3), peak-demand days determine the stress on the delivery system.

[4]Everett also provides LNG directly to the Mystic Power Plant and the National Grid utility company. In addition, Everett is capable of delivering LNG directly to utilities or even end users by truck at the capacity of 0.1 Bcf/day. Two additional regasification terminals, offshore buoy-systems Neptune and Northeast Gateway, both near Everett, are usually inactive.

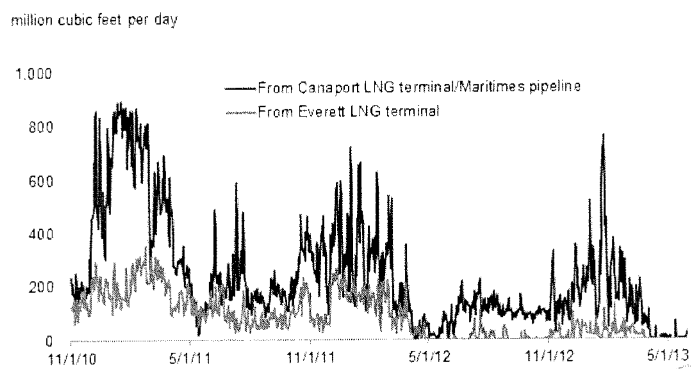
Figure 3. January average natural gas basis and daily consumption in New England



Source: U.S. Energy Information Administration, Bloomberg LP

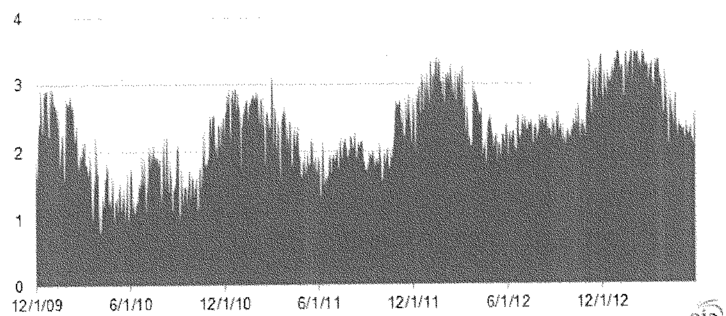
In the winter of 2012-13, LNG supply from Canaport via M&N and from Everett declined (Figure 4), and as a result, the other primary sources of supply, the AGT and TGP pipelines, were almost fully utilized and thus stressed in many days of the winter (Figure 5). This situation has been repeated as the winter of 2013-14 reaches a midpoint, and the forward basis continues to spike.

Figure 4. New England's swing supply of natural gas



Source: U.S. Energy Information Administration

Figure 5. New England natural gas supply from TGP & AGT pipelines
billion cubic feet per day (Bcf/d)

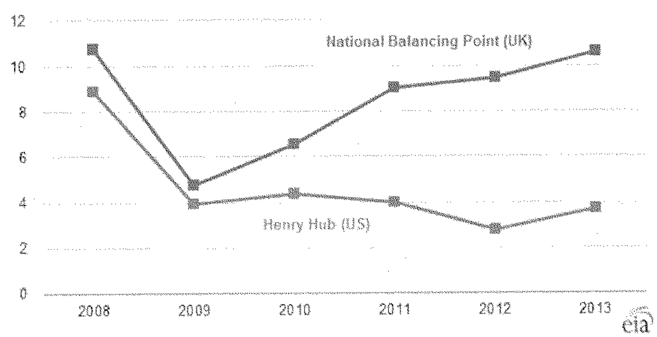


Source: U.S. Energy Information Administration

Some of the natural gas from M&N and Everett is delivered to New England through their interconnections to TGP and AGT. In addition, Everett delivers up to 0.7 Bcf per day directly to the 1,951-magawatt (MW) Mystic power plant, the National Grid utility company, and LNG users. New England also receives natural gas directly from M&N, Iroquois, and the Pacific Northern Gas pipelines in addition to the delivery points on TGP and AGT.

International natural gas and LNG markets. The reduction in LNG imports into New England is a consequence of the growth in U.S. shale gas production since 2010, which has contributed to a reduction in U.S. natural gas market prices relative to those in other world markets. The price spread between the U.S. benchmark price at Henry Hub and the United Kingdom (U.K.) benchmark price at National Balancing Points widened to $6.91/MMBtu in 2013 from $0.83/MMBtu in 2009 (Figure 6).

Figure 6. Average spot natural gas prices

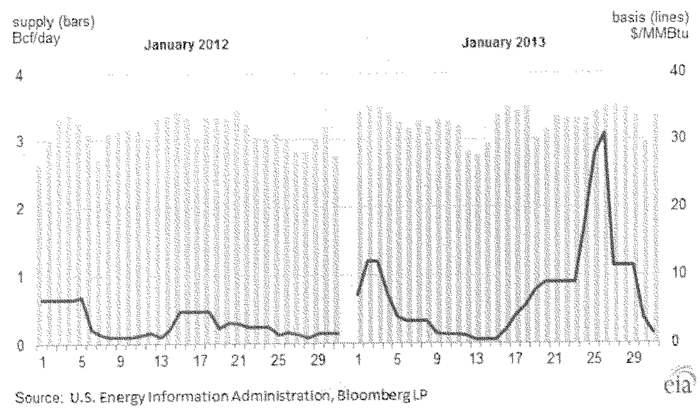


Source: Bloomberg LP

The growing price spread between U.S. and global markets led to the reduction in LNG imported and then sent from the Canaport (through M&N) and Everett LNG terminals (through TGP and AGT), and contributed to the upward price pressure in the New England market.

Effect of limited peak supply on New England prices. The price effect of a decline in peak supply is evident when comparing January 2013 with January 2012. Both months had several days when the market called for supply close to peak capacity of 3.5 Bcf/day from TGP and AGT. The basis in January 2013, however, rose substantially higher than the basis in January 2012, reaching over $30/MMBtu on January 26, 2013, while remaining under $9/MMBtu the entire month of January 2012 (Figure 7).

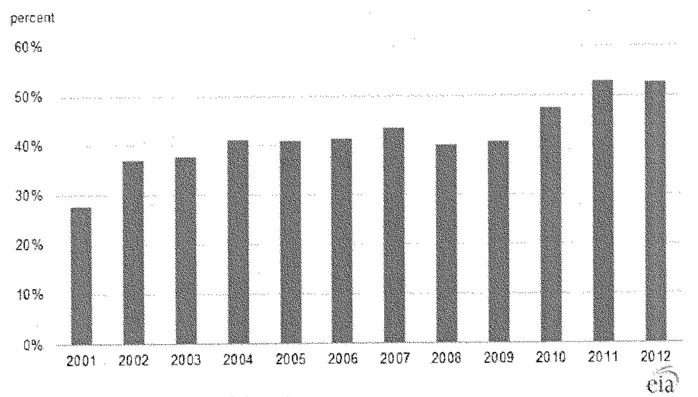
Figure 7. NE natural gas supply from TGP and AGT and basis, Jan 2012 vs. Jan



Source: U.S. Energy Information Administration, Bloomberg LP

Increasing electric power sector natural gas use in New England. Relatively lower natural gas prices in the United States, compared with the United Kingdom, not only led to declines in LNG imports but contributed to increased use of natural gas in power generation. In New England, natural gas use for electricity generation made up about a third of the region's natural gas consumption in 2013, averaging 1.2 Bcf per day. Since 2010, a trend of less expensive natural gas relative to other fuels has led to an increase in the share of total electricity generated by natural gas in the region (Figure 8).

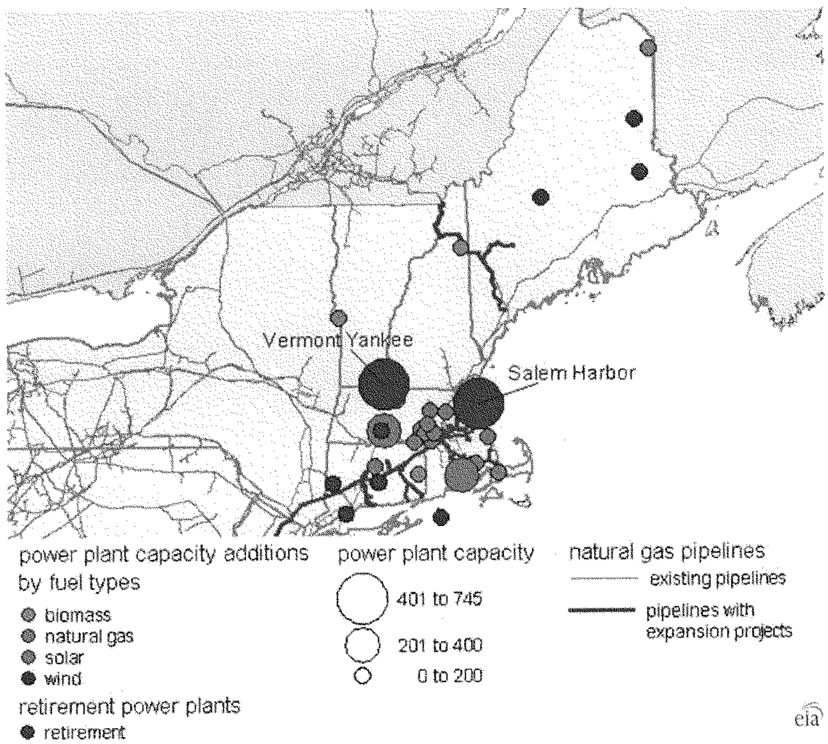
Figure 8. Natural gas share of total generation



Source: U.S. Energy Information Administration

This price pattern has increased the use of natural gas-fired capacity in the region and contributed to generally lower wholesale power prices. The lower wholesale power prices along with some environmental regulations at the regional and national levels have contributed to planned retirements of some large electric power plants in New England that use other fuels **(Figure 9)**, including Vermont Yankee (a 620-MW nuclear generator with a planned retirement date of December 2014) and Salem Harbor (a 744-MW coal- and oil-fired power plant with a planned retirement date of June 2014). The planned retirement of the Vermont Yankee and Salem Harbor power plants could result in as much as 0.11 Bcf per day of additional natural gas demand in the power sector during winter months, if typical demand patterns hold and all the output of these units is replaced by natural gas generation.

Figure 9. New England planned energy infrastructure changes between 2013 and 2016



Source: U.S. Energy Information Administration.

Increased pipeline utilization rates on peak days create physical stress on the natural gas transport system, which leads to reliability concerns for electric power sector deliveries. These deliverability concerns led the Independent System Operator of New England (ISO-NE), the electric grid operator for the region, to create a special winter reliability program for this winter. The program includes:

- demand-response program;
- incentives to ensure oil-fired generators increase their fuel inventories;
- payments to dual-fueled units for testing their capacity to use oil; and
- some changes to the market-monitoring procedures aimed at increasing the flexibility of dual-fueled units

The deliverability problems cited in the ISO-NE winter reliability program are a key reason to have oil-fired backup and dual-fired unit capacity in the region.

Potential solutions

There are a number of potential solutions to lessen the impact of limited peak supply at peak demand times.

Pipeline expansion to New England. With rising natural gas output from the Marcellus production field, pipeline expansion to move this gas to New England is one option for alleviating market stress. The key is to deliver more natural gas to Massachusetts, especially the Boston area, because it is the largest market in New England. Major energy infrastructure projects in metropolitan areas such as Boston and New York City, however, are capital intensive. Regulated pipeline companies typically seek financial assurance by signing long-term firm transport capacity contracts with shippers. Companies that sign firm capacity contracts will benefit financially when spreads widen substantially in New England. On the other hand, firms signing these contracts also assume the financial liability.

In 2011, Spectra Energy (operator of the Algonquin pipeline) proposed the Algonquin Incremental Market (AIM) Project to expand its citygate capacity by a nonbinding nomination of 1 Bcf/day. In December 2013, the proposed capacity expansion was 0.33 Bcf/day, with the target completion in November 2016.[5] The size of the pipeline capacity expansion was reduced 65% from the original proposal because of lack of interest in signing up for long-term firm transport capacity contracts.[6] So far, only regulated utilities, including UIL Holdings, Northeast Utilities, National Grid, and NiSource, have shown a willingness to absorb the financial cost embedded in the long-term firm contracts.[7] In addition to Spectra, Tennessee Pipeline proposed an expansion project of up to 1.2/day into the Boston area, with expected completion in 2018.[8]

In general, public utility commissions (PUCs) require utilities to seek approval for signing long-term contracts and the rate hikes required to pay for them. The reduction in the proposed expansion capacity of the AIM project may indicate hesitation by and their regulators. Pipeline rates approved by FERC and utility rates approved by PUCs need to be consistent for success in pipeline expansion.

U.S. LNG. Utilities in New England might also enhance winter supply reliability by investing directly in proposed U.S. LNG liquefaction plants and receiving occasional LNG cargoes as a stipulation of their investment. It may be possible that investing a relatively small amount of capital could provide access to this source of swing supply during periods of high winter demand in New England.

Physical peaking option contracts. To mitigate the market risk of such high-price patterns, one effective instrument is a physical peaking option to manage the physical supply and financial price risk on peak

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[5]Algonquin Incremental Market (AIM) Project, Spectra Energy, http://www.spectraenergy.com/Operations/New-Projects-and-Our-Process/New-Projects-in-US/Algonquin-Incremental-Market-AIM-Project/ and DEEP Electric IRP Gas Stakeholder Meeting, Hartford, CT, September 20, 2011, Spectra Energy, http://www.ct.gov/deep/lib/deep/energy/irp/naturalgas/irp_2012_stakeholdermtg_naturalgas_spectraenergy_092011.pdf
[6]Utilities seek boost in region's natural gas, the Boston Globe, November 5, 2013, http://www.bostonglobe.com/business/2013/11/05/agreements-with-utilities-moving-pipeline-expansion-forward/8uyv2tJ9dqhXReB3BxgkYN/story.html.
[7]*NGA Pre-Winter Briefing*, Spectra Energy, November 6, 2013,
[8]*Northeast Gas Association Pre-Winter Briefing 2012 / 2013*, Kinder-Morgan, December 3, 2012, www.northeastgas.org/pdf/d_skipworth.pdf

demand days.[9] The contract buyer purchases a fixed quantity of gas from a peak supplier, such as an LNG storage facility, for a specified open window of time, price, and number of days on which the buyer can call for delivery of the gas at the agreed price and volume. The buyer pays the option premium to the LNG facility for this right. Volumes tend to be small, as the right to buy the gas would only be exercised as an emergency on days of peak demand, such as a very cold day when the spot price spikes.

However, in recent years, New England has developed problems that may prevent the economic use of an LNG-based peaking option:

- The increased frequency of price spikes has made options more expensive.
- Supplies from Canada's eastern offshore production areas declined, making the overall premium more expensive.
- Because LNG is traded globally, higher international LNG prices have increased competitive buying pressure for the gas.

With the increase in the forward basis for the winter of 2013-14 as described above, Canaport and Everett may be able to lock in LNG supplies to New England, but the cost to consumers is higher than in recent years because of the above factors.

Fuel substitution. In periods of high natural gas prices, users could substitute less-expensive fuels if possible. Natural gas consumption by the power sector declined in January 2013 compared to January 2012 (Figure 10), encouraged in part by higher natural gas spot prices. When natural gas prices hit a historic low in the summer of 2012, it was widely reported that many power generating units switched from eastern coal to natural gas. More importantly, during the peak-demand season when natural gas prices spike, power generating units tend to switch from natural gas to fuel oil. In addition to power generation, other natural gas consumers, such as universities, factories, or even residential customers, also benefit from optimizing their fuel strategy when a backup-fuel is available. Regulatory restrictions and other issues, however, may limit the extent that fuel substitution can occur, which will constrain the effect of fuel switching even in periods of peak demand.

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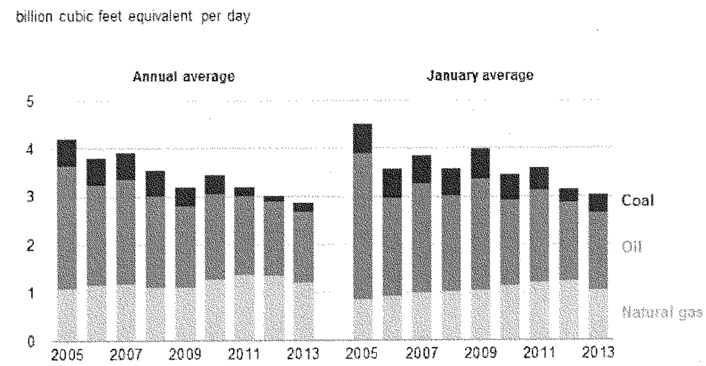
[9] *Imported LNG: a Reliable Peaking Option for New England*, Repsol Presentation, April 30, 2013, www.northeastgas.org/pdf/v_morrissette_repsol.pdf and *GDF Suez Gas NA*, GDF Suez Presentation, December 3, 2012, www.northeastgas.org/pdf/g_whitney.pdf.

Figure 10. New England fuel consumption for power generation, annual vs. January average



Source: U.S. Energy Information Administration

Demand curtailment. Utilities in both New England and New York City are able to offer interruptible services to customers with dual-fuel capability. New York City has a widely used feature in which utilities offer retail customers firm services and interruptible services. Natural gas consumers with dual-fuel backup have an option to buy interruptible natural gas services at a substantial discount. Consumers with interruptible services can choose to switch from natural gas if another fuel is less expensive. If market activities fail to reduce peak demand below available supply, however, utilities make curtailment calls to ensure supply reliability, which require natural gas consumers with interruptible services to switch from natural gas to another fuel regardless of costs. Customers who fail to comply will incur monetary penalties.[10]

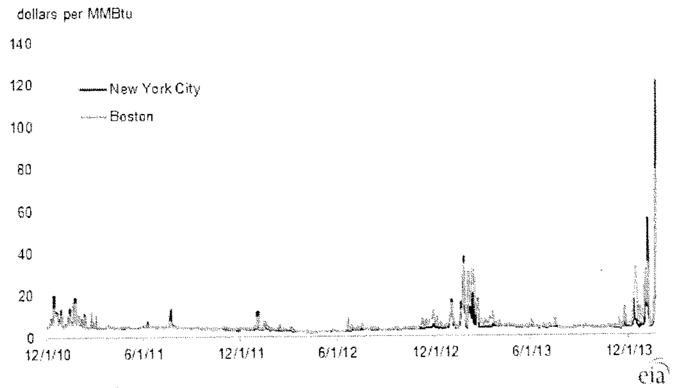
The retail curtailment mandate lowers peak demand, which helps reduce price spikes during high-demand periods. When curtailment is called, customers may have to pay higher prices to switch from natural gas to alternative fuels, but they may still be better off than paying higher premiums up front to purchase firm services.

Price comparison between New England and New York City. Both Boston and New York City had natural gas price spikes in the winter of 2012-13 (Figure 11). So far in the winter of 2013-14, however, natural gas price spikes in New York City remained less frequent than in Boston, although on the coldest days the spot prices tend to be higher in New York City than in Boston. Natural gas pipeline expansion into the New York City area may be providing a buffer against the frequency of price spikes this winter. Encouraged by the proximity to Marcellus natural gas production and rising baseload consumption, pipeline capacity increased, and this likely contributed to the mitigation of price spikes in the New York

[10] OFO and Curtailment, SCANA Energy Marketing, http://www.scanaenergymarketing.com/SCANA.ESS.Templates/Content/Content100.aspx?NRMODE=Published&NRNODEGUID=%7bF78CDC8B-8C39-40A8-961E-D84EB1183F1A%7d&NRORIGINALURL=%2fen%2fnatural-gas-education%2fofo-and-curtailment%2f&NRCACHEHINT=Guest#curtailment

City area. In addition, effective retail demand curtailment in New York City provides peak supply reliability and, in turn, reduces price volatility.

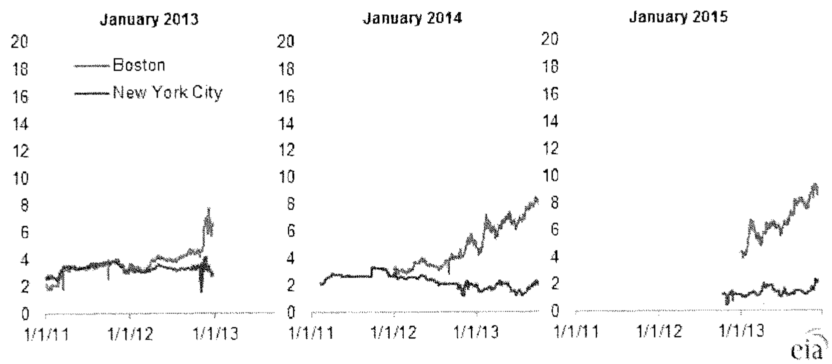
Figure 11. Natural gas spot prices in Boston and New York City



Source: Bloomberg LP

The forward basis markets have also shown widening differentials (Figure 12). At Transco Zone 6 New York, the January 2013 forward basis settled around \$3/MMBtu, while the Algonquin Citygate January 2013 forward basis reached more than \$6/MMBtu. The deviation widened rapidly in 2013. The January 2014 forward basis at Transco Zone 6 New York settled at \$4.89/MMBtu, but the Algonquin Citygate forward basis for the same contract settled at \$17.41/MMBtu. The 2015 basis differential also remains wide, indicating the market expectation that New England's peak supply problems will continue into the winter of 2014-15.

Figure 12. Natural gas forward basis for January 2013, January 2014, and January 2015
dollars per MMBtu



Source: Bloomberg LP

Conclusion. Limited peak supply contributed to substantial increases in New England natural gas prices and basis on high-demand days this winter and last winter. New York City reduced spikes in prices and basis by adding pipeline capacity and by using retail demand curtailment, solutions that could help New England as well. Companies have proposed pipeline expansion, but getting the financial commitments to move forward has been difficult because the additional capacity may only be necessary for short periods during the year. Pipeline expansion may become more viable if baseload consumption of natural gas to generate electricity continues to increase. The high January 2015 forward basis for Boston indicates that market participants do not expect a resolution to these peak supply issues before next winter.

Mr. WHITFIELD. Thank you very much, Mr. Sieminski. Mr. Waxman has come in, and we will give him an opportunity to make his opening statement at this time.

OPENING STATEMENT OF HON. HENRY A. WAXMAN, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF CALIFORNIA

Mr. WAXMAN. Thank you very much, Mr. Chairman. I welcome all of our witnesses today. There is a significant energy transition underway in the United States, and we are going to hear today about how we need to modernize our energy infrastructure in light of this transition. Building a modern energy infrastructure for the 21st century requires more than just drilling more wells, laying more pipelines, filling more rail cars with crude oil, and putting more tanker trucks on our highway. A modern 21st energy infrastructure isn't modern at all unless it takes climate change into account.

We have a rapidly diminishing window to act to reduce our carbon pollution before the catastrophic impacts of climate change are irreversible. That means that the energy infrastructure decisions we make today will have a real and direct impact on whether we can limit climate change in the future. We need to understand this risk before we lock in infrastructure that will produce carbon pollution for decades to come. Every responsible business executive in the country knows that there will be no certainty in energy policy until we address climate change.

A modern 21st century infrastructure also needs to be resilient. Earlier this week the Government Accountability Office released a report finding that U.S. energy infrastructure is increasingly vulnerable to a range of climate change impacts, such as severe weather and sea level rises. We need to prepare our infrastructure to withstand climate related disruption. We also need to have an infrastructure that is efficient, and minimizes waste.

A good example of inefficiency in today's system is methane. Far too often methane, a potent greenhouse gas, leaks into the air during the production, processing, and distribution of oil and natural gas. In North Dakota oil companies are flaring natural gas as a waste product, rather than building the infrastructure to get these resources to market. We need to find solutions to stop this dangerous pollution and put this gas to productive use.

The future will belong to the country that builds an energy infrastructure to support a cleaner, low carbon economy. It is our responsibility to lead the country in that direction.

I appreciate this chance, Mr. Chairman, to make this statement. I thank the witnesses for being here today, and look forward to their testimony.

Mr. WHITFIELD. Thank you, Mr. Waxman. It is my understanding that Mr. Upton is going to waive his opening statement?

Mr. UPTON. No, I would say just insert it in the record, but thank you.

[The prepared statement of Mr. Upton follows:]

PREPARED STATEMENT OF HON. FRED UPTON

North America's growing oil and natural gas abundance is easily the best energy news we've had in decades. The benefits for jobs, energy affordability, and national security are nothing less than staggering. In fact, a recent study by the Manhattan Institute finds that virtually all of America's economic growth in recent years is attributable to the oil and gas sector, and that without it we would have remained in recession. And since the energy output is projected to continue rising, the good news could get even better in the years ahead—but only if we play our cards right.

But producing more energy is only part of the job. We also must get it to the businesses and homeowners that need it, and expanded energy output presents a very significant infrastructure challenge. But with challenge comes opportunity, and building this architecture of abundance will create many jobs. An energy infrastructure expansion is a win-win for America—more jobs building and running it, and more affordable and secure energy because of it. The problems we will discuss at this hearing are good kind of problems to have.

Nonetheless, the Obama administration has been more of a hindrance than a help, both on energy production and energy infrastructure. The administration has placed so many energy-rich Federal lands off limits that a Congressional Research Service report found that all of the oil and gas increase is attributable to output from non-Federal lands. And the administration has been just as unhelpful on energy infrastructure as it has been on energy production. At this promising juncture in the nation's energy history, we need an administration that embraces the architecture of abundance. But instead, we often get Keystone-style delays and red tape.

Granted, each new pipeline project and other infrastructure upgrade raises legitimate safety and environmental concerns that must be addressed. But these concerns should not be used as an excuse for indefinite delays, as we have seen with Keystone XL. After all, new infrastructure increases safety.

Our inadequate energy infrastructure is already causing problems. This winter's regional propane shortage throughout Michigan and much of the Midwest is a case in point. When the temperatures dropped and demand grew, there was not enough infrastructure to transport the propane to the customers who needed it. In the words of Secretary of Energy Ernest Moniz, "what we are seeing play out is also just one example of where our energy infrastructure isn't quite ready for the task that we have today." Michigan has the largest number of propane-heated households of any State. I take this warning very seriously and want to look at how this can be avoided in the future.

I am convinced that we can create a new energy infrastructure to safely deliver the affordable energy that businesses and families need. We welcome the task of creating this architecture of abundance, and Congress must take action to remove any impediments to further progress.

Mr. WHITFIELD. Thank you. At this time, Mr. Santa, you are recognized for 5 minutes for your opening statement.

STATEMENT OF DONALD F. SANTA

Mr. SANTA. Good morning, Chairman Upton, Chairman Whitfield, and Ranking Member Waxman, and members of the subcommittee. My name is Donald Santa, and I am president and CEO of the Interstate Natural Gas Association of America, or INGAA. INGAA represents interstate natural gas transmission pipeline operators in the U.S. and Canada. Thank you for the opportunity to share INGAA's views. Our analysis points to the need for the U.S. to build significant new natural gas infrastructure. Simply put, we need to keep pace with the changing natural gas supply and demand picture. Infrastructure designed to meet the challenges of the past will not necessarily meet the challenges of the future. Congress can help in one area, that I will touch upon in a few moments.

I do not have to tell anyone that this has been a demanding winter. With but extremely few exceptions, there have been no service disruptions or curtailments for natural gas pipeline customers who contracted for reliable, firm service. The rare disruptions were caused by mechanical difficulties, and were limited only to a day or so. Given the magnitude of the demand across much of the country, the extreme operating conditions, and the resulting stress placed on the overall system, the natural gas transmission pipeline industry's performance has been remarkable.

This contrasts with what happened in the 1970s. A combination of government policies at that time discouraged natural gas supply and infrastructure development. Consumers, and many of our nation's leaders, believed that the U.S. was running out of natural gas. This lack of interstate supply and interconnected infrastructure, coupled with severely, unusually cold winters in the late 1970s, caused significant natural gas service disruptions. Schools closed for extended periods, and some businesses ceased operations until warmer weather arrived.

We have come a long way since then. Congress decontrolled natural gas well head prices, thus providing an incentive to explore and produce new natural gas. The Federal Energy Regulatory Commission restructured the interstate pipeline sector, unbundling commodity sales from transportation, and thereby gave pipeline customers the opportunity to realize the benefits of competition at the well head.

So we have gone from the mistaken impression that the U.S. was running out of gas to being the world's largest producer of natural gas. Our robust nationwide pipeline network is the envy of the world. Most major markets, and all major producing basins, are connected to multiple pipelines, and as a result, we have competition among entities that were assumed to be natural monopolies several decades ago. This phenomenal transformation of the U.S. energy sector has provided our country a unique competitive advantage in the global market. No other country has the combination of abundant natural gas supply and robust pipeline infrastructure. Additional natural gas transmission pipelines, however, will be needed to keep pace with the rapid development of new natural gas resources, and the increase in natural gas demand.

Two things are necessary to make this infrastructure development possible. The first is proper market signals for new capacity. In most regions, this is not a problem. Shippers sign contracts for proposed firm pipeline capacity, and if enough capacity is contracted, a pipeline project stands a reasonable chance of moving forward. Regions with restructured electricity markets, however, present real challenges. This is especially the case when such markets are capacity constrained, and rely heavily on natural gas fired generators. New England is the prime example.

We have encouraged the regional stakeholders to take steps that will create such price signals, and recent initiatives undertaken by New England States' Governors are promising. Still, the region has far to go in resolving the disconnect that has caused its consumers to pay such a premium for natural gas and electricity.

Beyond these market signals, the pipeline permitting process also much work efficiently. The House has debated legislation authored by Representative Mike Pompeo to bring some discipline and accountability to the pipeline permitting process, and to permitting agencies beyond FERC. We support this legislation, and hope the Senate will act soon to move it forward.

This winter has been challenging, but it would have been far worse without our new domestic natural gas abundance. Supply is only one side of the coin, however. The other side is infrastructure, because pipelines make it possible. The incentives to develop the shale gas, and the opportunities for consumers to realize its benefits, would not be the same without our robust, flexible, and expandable natural gas pipeline network.

Still, we should not assume that the current natural gas pipeline and storage infrastructure be sufficient to handle present and future natural gas supply development. Natural gas has given the U.S. a phenomenal advantage. To realize this advantage fully, we need to build the infrastructure that will permit all Americans to benefit from the shale revolution.

I thank the subcommittee for the opportunity to testify.

[The prepared statement of Mr. Santa follows:]

STATEMENT OF
DONALD F. SANTA
PRESIDENT AND CEO
THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

BEFORE THE
SUBCOMMITTEE ON ENERGY AND POWER
COMMITTEE ON ENERGY AND COMMERCE
U.S. HOUSE OF REPRESENTATIVES

REGARDING THE
BENEFITS OF AND CHALLENGES TO ENERGY ACCESS
IN THE 21ST CENTURY

MARCH 6, 2014

Good morning Chairman Whitfield, Ranking Member Rush and members of the Subcommittee. My name is Donald F. Santa, and I am President and CEO of the Interstate Natural Gas Association of America, or INGAA. INGAA represents interstate natural gas transmission pipeline operators in the U.S. and Canada. Our 26 members account for virtually all of the major interstate natural gas transmission pipelines in North America and operate about 200,000 miles of transmission pipe in the U.S.

Thank you for the opportunity to share INGAA's views on this topic. Our analysis, and what we actually experienced during this extremely cold winter, all point to the need for the U.S. to build significant new natural gas infrastructure. Simply put, we need to keep pace with the changing natural gas supply and demand picture. Infrastructure designed to meet the challenges of the past will not necessarily meet the challenges of the future. Congress can help in one area that I will touch upon in a few moments.

I do not have to tell anyone that this has been a demanding winter. You have no doubt heard about the challenges of serving energy consumers throughout the U.S. during these extended periods of extreme cold. With but extremely few exceptions, there have been no service disruptions or curtailments for natural gas pipeline customers that contracted for reliable, firm service. The rare disruptions were caused by mechanical difficulties and were limited to only a day or so. Given the magnitude of demand across much of the country, the extreme operating conditions and the resulting stress placed on the overall system, the natural gas transmission pipeline industry's performance has been remarkable.

It is worth contrasting this experience with what occurred in the 1970s. The natural gas marketplace was, in those days, completely different. The federal government set the wellhead price of natural gas sold in interstate commerce, intrastate markets in producing states were wholly separate from the interstate market, and the answer for shortages in the inflexible interstate market was a government-dictated allocation of supply based on curtailment priorities. Consumers, and many of our nation's leaders, believed that the U.S. was "running out of natural gas." This lack of interstate supply and interconnected infrastructure, coupled with several unusually cold winters in the late 1970s, caused significant natural gas service disruptions. Schools closed for extended periods, and some businesses ceased operations until warmer weather arrived.

We have come a long way since then. Congress decontrolled natural gas wellhead prices, thus providing an incentive for entrepreneurs to explore for and produce new natural gas supplies. The Federal Energy Regulatory Commission (FERC) restructured the interstate pipeline sector, unbundling commodity sales from transportation, and thereby gave pipeline customers the opportunity to realize the benefits of competition at the wellhead.

The restructuring of the nation's natural gas markets that began with Congress' decision in 1978 to initiate a phased decontrol of wellhead natural gas prices has been a remarkable success. We have gone from the mistaken impression that the U.S. was "running out of gas" to being the world's largest producer of natural gas. Our robust, nationwide pipeline network is the envy of the world. Most major markets and all major producing basins are connected to multiple pipelines, and as a result we have competition among entities that were assumed to be "natural monopolies" several decades ago. This phenomenal transformation of our energy sector has provided our country a unique competitive advantage in the global market. No other country has this combination of abundant natural gas supply and robust pipeline infrastructure.

Natural Gas Pipeline Model

One of the major challenges today, as we continue to develop and consume our natural gas resources, is building infrastructure that keeps pace with the evolving supply and demand realities. In connection with this, it is critically important to understand that this is not a "build it and they will come" business. Pipeline infrastructure is not built on speculation. Instead, natural gas transmission pipelines are built to meet the needs of firm shippers willing to sign long-term contracts for pipeline capacity utilization. Why is this?

First, natural gas transmission pipelines are capital intensive, long-lived, immobile assets. Compared with other modes of transportation -- a ship, an airplane, a train or a truck -- a pipeline cannot be relocated in response to shifts in the marketplace. While pipelines can be repurposed in some cases (for example, by changing the direction of product flows or converting a pipeline from natural gas to crude oil transportation), such opportunities typically do not exist. Generally speaking, once a pipeline is in the ground, the operator has made a long-term commitment.

Next, in order for FERC to grant a pipeline company authority to construct an interstate natural gas pipeline, it must find that the pipeline is needed. In the terms used by the Natural Gas Act, FERC must find that the project meets the "public convenience and necessity." While this can be demonstrated in a number of ways, the most typical way is for the pipeline company to present service agreements in which shippers commit to paying for firm service over a term of multiple years. In other words, if enough customers are willing to pay reservation charges under a multi-year contract for firm pipeline service, the need for the proposed pipeline has been demonstrated.

Finally, FERC regulates the rates charged by interstate natural gas pipelines, and these rates are established on a cost-of-service basis. Consequently, if the pipeline bets right, it recovers its investment, including the return-on-investment that is part of its regulated rate. If it bets wrong, it does not fully recover its investment. There is no opportunity, however, for a pipeline to collect a premium if it bets correctly and the market value of the transportation exceeds to regulated rate (since it can't charge more than the regulated rate). Given this asymmetric risk-reward ratio, there is no reason for interstate natural gas pipeline companies to "build it" and hope "they will come."

Another foundational principle of the natural gas industry is that pipeline customers are responsible for ensuring their own reliability by taking a portfolio of gas services that meets their needs. Unlike the electric power industry, no "reserve margin" is built into natural gas pipelines. There is no overbuilt capacity to be called upon in a pinch. Pipelines are built to meet the needs of firm customers and firm customers only. If a customer needs extremely reliable service, then it can contract for the firm services that produce that level of reliability. In the alternative, if a customer places a premium on minimizing cost, it can purchase interruptible services and save money. But just as its name implies, interruptible service is subject to interruption – particularly on the coldest days of the year – as many such customers learned this winter.

In connection with this, it is worth noting that electric power generators operating in restructured wholesale power markets (in other words, markets administered by independent system operators and regional transmission organizations) typically do not hold firm pipeline capacity. Rather, they rely upon interruptible pipeline capacity or firm capacity acquired in the secondary market (so-called released capacity that is re-sold by firm shippers, usually on a short-term basis). In fact, in most cases, such generators do not hold any pipeline capacity, and instead look to marketers that hold interruptible or released capacity. This works most of the time, but during periods of peak demand, interruptible service can be interrupted and released capacity can be recalled. This is important when thinking about whether pipeline infrastructure will keep pace with demand, because, as I mentioned, the natural gas transmission pipeline companies build to serve firm shippers, and firm shippers only. This can create problems in markets that already are capacity constrained, such as New England. The Subcommittee, I know, has focused on natural gas/electric power integration in several previous hearings.

Midstream Infrastructure Requirements to 2035

We agree that the U.S. needs new pipeline infrastructure, and indeed not only for natural gas transportation but also for natural gas liquids, crude oil and refined petroleum products. The INGAA Foundation, an affiliated entity, has sponsored assessments of the need for new pipeline infrastructure for more than 15 years. These assessments have projected such needs looking forward approximately 20 years. In 2011, the Foundation expanded its assessment to include not only natural gas midstream assets but also crude oil and natural gas liquids.

The INGAA Foundation will release its new assessment of U.S. and Canadian midstream infrastructure requirements, through 2035, on March 17. While I cannot yet provide the details of the report, I can outline the key points.

First, we are estimating that both annual and total natural gas infrastructure capital expenditures, through 2035, will need to be significantly higher than the previous estimate. This is in part because the latest report is counting several types of facilities that were not included in the 2011 report. In addition, however, the assessment foresees a substantial increase in the need to build pipeline "laterals" to power plants, gas storage facilities and processing plants.

Spending for natural gas transmission lines must remain strong in order to keep pace with the need to link new supplies to markets. The assessment, however, projects a greater need for shorter, regional pipelines that connect supply to the existing infrastructure rather than lots of new, long distance pipelines. For example, there will be significant demand for systems to carry new natural gas supplies from Pennsylvania and West Virginia to nearby markets such as New York and New England. There also will be demand for pipeline capacity to export such production to other regions; in many cases, this will involve redirecting the flow on pipelines that formerly delivered natural gas to such markets.

The estimates for petroleum and natural gas liquids infrastructure also are up significantly, again due in part to including some types of infrastructure that were not included in the 2011 study. Still, the main driver for the increased need for such midstream infrastructure is the dramatic growth in U.S. oil production.

A Word on Pipeline Safety

Let me turn to pipeline safety for a moment. The San Bruno, California tragedy in 2010 was a wake-up call for the natural gas pipeline industry. It reinforced for pipeline operators that pipeline safety is not just a matter of regulatory compliance; it is part of the industry's social license to operate. Therefore, it is critical that we get it right. This is why the INGAA board of directors committed to a goal of zero pipeline safety incidents. Our board did this in advance of Congress reauthorizing the Pipeline Safety Act, and in advance of any new regulations required by that law. We followed this up with a set of concrete, actionable commitments to improve pipeline safety.

Pipeline integrity management programs provide the means to evaluate and reduce pipeline risks. The 2002 Pipeline Safety Act reauthorization directed the federal pipeline safety regulator at the Department of Transportation (DOT) to develop and issue regulations that address risk analysis and integrity management programs. For example, the operators of natural gas transmission pipelines were required to perform a baseline inspection of all pipeline segments in populated areas within 10 years, and to re-inspect those segments every seven years thereafter. The baseline assessments were completed at the end of 2012, and even though a small percentage of pipeline mileage is within populated areas, a far greater portion of the total pipeline mileage was inspected – approximately 60 percent of total mileage to date. INGAA has committed to expand the reach of integrity management to include the entire system, and Congress directed DOT to explore this as well, as part of the 2012 reauthorization.

The San Bruno accident emphasized the importance of knowing what is in the ground. In other words, do pipeline operators have good records concerning the particular materials and construction practices used to build their pipelines and whether those facilities were tested prior to entering service? And if not, what must operators do to demonstrate that their pipelines are fit for service? These questions were a focus of the 2012 law, and the INGAA membership has committed to ensuring adequate records and testing for all gas transmission lines located near people.

Need for New Pipelines

We recognize, and our data supports, that new natural gas transmission pipelines will be needed to keep pace with the rapid development of new natural gas resources and the increase in natural gas demand. Two things are necessary to make this infrastructure development possible. The first is proper market signals for new capacity. In most regions, this is not a problem. Shippers sign contracts for proposed firm pipeline capacity, and if enough capacity is contracted, a pipeline project stands a reasonable chance of moving forward. Regions with restructured electricity markets, however, present real challenges. This is especially the case when such markets are capacity constrained and rely heavily on natural gas-fired electricity generators. As noted already, New England is the prime example. We have encouraged the regional stakeholders to take steps that will create such price signals and recent initiatives undertaken by the New England states' governors are promising. Still, the region has far to go in resolving the disconnect that has caused its consumers to pay such a premium for natural gas and electricity,

I would note that other regions do not face this mismatch of demand and supply for natural gas infrastructure. Like New England, Florida is also "at the end of the pipeline system," and is heavily dependent on natural gas for power generation. But Florida has not experienced the same problem getting adequate pipeline capacity built. This is because the local electric utilities have the ability, via the Florida Public Service Commission, to contract for firm pipeline service. This support from state regulators, and the ability to recover the cost associated with ensuring reliability in electric rates, makes all the difference in terms of getting needed natural gas infrastructure built.

Beyond these market signals, the pipeline permitting process also must work efficiently. The House has debated (and approved) legislation (H.R. 1900) authored by Rep. Mike Pompeo to bring some discipline and accountability to the pipeline permitting process. We support this legislation and hope the Senate will act soon to move it forward.

Let me address one question that has been raised in connection with H.R. 1900. Some have questioned the need for the legislation, because "the FERC approves pipeline certificates in one year or less." This is certainly true, and if FERC were the only entity from which the sponsor of a proposed pipeline needed approval, that would be terrific.[1] But, in order to proceed to construction, a proposed pipeline also must obtain other permits from a myriad of federal and state agencies. It is with these permits that the real delays happen, and where real discipline and accountability are needed. INGAA's analysis demonstrates that these agency permits (and not the FERC certificate process) are being delayed for longer periods than in years past. This is not a positive trend, and it is precisely why H.R. 1900 is needed. So please, if you want to take full advantage of new natural gas supplies by constructing the pipeline network that will be needed to keep pace with dynamic shifts in supply and demand, enacting H.R. 1900 is one of the few areas where Congress can make a measurable improvement.

Conclusion

A recent Forbes magazine article summed up this winter with the headline "Thanks to Fracking, Natural Gas Supplies (Barely) Withstand 'Polar Vortex' Assault." It is certainly true that this winter would have been a far more troublesome without our new domestic natural gas abundance. But supply is only one side of the coin. The other side is infrastructure, and, indeed, pipelines make new shale gas supplies possible. We should not assume that the current natural gas pipeline and storage infrastructure will be sufficient to handle present and future natural gas supply development. Natural gas has given the U.S. a phenomenal advantage. To realize this advantage fully, we need to build the infrastructure that will permit all Americans to benefit from the shale revolution.

I thank the Subcommittee for the opportunity to testify today.

[1] Note, however, that when the time needed to participate in the FERC pre-filing process is included, the actual time needed to obtain a certificate of public convenience and necessity can approach 24 months. The deadline for FERC contained within H.R. 1900 only pertains to the formal application process, and does not include a deadline for pre-filing activities that take place before a formal application is filed.

Mr. WHITFIELD. Thanks very much. And, Mr. Roldan, you are recognized for 5 minutes for an opening statement.

STATEMENT OF RICHARD R. ROLDAN

Mr. ROLDAN. Thank you, Mr. Chairman, and members of the subcommittee. I am Richard Roldan, president of the National Propane Gas Association. I appear before you today on behalf of nearly 3,000 member companies that produce, transport, and sell propane on both a wholesale and retail basis. By far the largest segment of our association is made up of retail propane marketers who provide the fuel to heat nearly six million American homes. I am going to be brief in my remarks this morning to save as much time as possible for your questions, and I ask that my extensive statement be placed in the record.

Mr. Chairman, this is a particularly timely hearing, considering that propane retailers in several regions of the country face supply and distribution constraints this winter. I want to stress that our highest priority is to safely and reliably serve the nearly six million households that depend on propane to heat their homes. And I would like to point out that the vast majority of retail marketers were able to do just that, despite the significant challenges they faced.

Given the experience of this winter, I believe it is incumbent upon us, as an industry, to understand the causes and contributing factors, and to propose concrete practices and policy recommendations to prevent a recurrence. In our written statement, we noted the role that cold weather played. The number of heating degree days this season was 10 percent higher than the previous year, and 15 percent higher than the year before that. Last fall's grain harvest came in later, wetter, and it seemed all at once. This forced farmers to use five times the amount of propane to dry the grain that was used the previous year. Altogether, weather driven demand, coupled with record crop drying usage, resulted in nearly a billion gallons of additional demand.

Now I would like to point out the role that exports have played this year. In recent years we transitioned from being a propane importing country to being a propane exporting country. Today propane is 100 percent American made. That is offset by the fact that the U.S. now exports one out of every five gallons, and those numbers are growing. We believe we need to review our current export policies with respect to propane, and consider its effect on consumers and energy reliability.

Finally, Mr. Chairman, I want to alert the subcommittee to the dramatic transition that is taking place with the fuel distribution infrastructure in this country. Record production of crude oil, natural gas, and propane from shale formations is changing the historical flow of fuels. Pipelines that once carried propane and other products from the Gulf Coast, where they were produced, northward are now being reversed to carry other products toward the Gulf Coast. That, in turn, is place greater pressure on railroads and highways. I think it is critical that we understand these changes, and the effects that they have on consumers.

Mr. Chairman, I would be remiss if I closed without extending our deep appreciation to the people who helped stabilize the situation. That includes members of this subcommittee, as well as other members of Congress. The level of cooperation between agencies, among Governors of affected States, and our transportation partners, some of whom are represented at this witness table, was not less than extraordinary, and have made a real difference.

I would like to thank in particular the Department of Energy, the Federal Energy Regulatory Commission, the Department of Transportation. And I personally would like to commend Secretary Moniz and Secretary Foxx for their personal attention.

Mr. Chairman, that concludes my remarks.

[The prepared statement of Mr. Roldan follows:]

One-page summary of
NPGA's Statement for the Hearing Entitled
"Benefits of and Challenges to Energy Access in the 21st Century:
Fuel Supply and Infrastructure"

NPGA is pleased to present testimony for this important hearing. It is particularly timely, considering that this winter propane retailers in several regions of the country have faced supply constraints of propane used for home heating and agricultural needs.

The propane delivery infrastructure is undergoing a dramatic transition, brought on by the production of previously unimaginable amounts of domestic fuels, including propane. The result has been a change in the historical flow of fuels, which has been disruptive to energy infrastructure and energy markets. The challenges for propane markets during the 2013/2014 winter have been exacerbated by this transformation of the energy delivery infrastructure. These challenges include:

- Dramatically increased propane exports;
- Reversal of propane pipelines which move substances away from propane market areas;
- Competition for rail transportation from other substances causing congestion.

Specifically with regard to the challenges of the 2013/2014 winter heating season, NPGA identifies a number of causes and contributing factors. We entered the heating season with average inventory levels, but consumption in 4Q13 increased by about 570 million gallons compared with the previous year. Demand was also higher due to crop drying and colder than normal weather.

The challenges of the heating season received early and consistent attention from federal and state officials. We were gratified by the response, and thank Energy Secretary Moniz, Transportation Secretary Foxx, the Federal Energy Regulatory Commission, the Small Business Administration, the State of Texas, and the Governors of those states that declared emergencies which allowed drivers to do their jobs unimpeded by hours of service regulations.

In order to ensure that such a winter never happens again, NPGA recommends the following:

- A rigorous and formal review of federal propane export policies;
- FTC investigation to ensure markets are performing properly;
- Improvement of timeliness and reliability of EIA inventory data, particularly on exports;
- FERC increased transparency of petroleum products pipeline operations;
- FERC should apply similar affiliate rules to petroleum products pipelines as exist with natural gas pipelines;
- Laws applicable to federal authority during emergencies should be revised to allow more focused thresholds suitable for narrow fuel emergencies affecting Americans;
- Expedited increases in storage infrastructure, including the Finger Lakes facility in NY.

Statement of the National Propane Gas Association Hearing before the Energy and Power Subcommittee "Benefits of and Challenges to Energy Access in the 21st Century: Fuel Supply and Infrastructure" March 6, 2014

The National Propane Gas Association (NPGA) is pleased to submit this statement for today's hearing. Our nearly 3,000 members – predominantly small, family-owned businesses – make up an industry that provides propane to fuel homes, farms, businesses and vehicles in all fifty states. The industry employs approximately 40,000 industry individuals nationwide. Propane is a non-toxic gas produced from natural gas processing and crude oil refining. Over 70 percent of propane produced in the U.S. comes from natural gas.

Today's hearing is particularly timely for the propane industry. During the 2013/2014 winter heating season, which we're still experiencing, propane retailers in several regions of the country have faced critical supply constraints of propane. The supply challenges in the Midwest have been of particular concern. Propane retailers have chosen to fill customer tanks to less than maximum levels to stretch their limited supplies. Propane suppliers have traveled long distances and waited in long lines at terminals where the availability of supply was unpredictable and where they have confronted historically high prices. These high costs have hurt businesses and, worse, threatened the ability of propane customers to purchase essential heating fuel.

Our testimony today provides examples of how America's energy future is changing, which in turn challenges existing energy flows and delivery infrastructures. We also present information on how laws affecting the propane industry were helpful, and also how we believe they could be strengthened. Our core principle in appearing before you today is that we must ensure that America's energy abundance continues to serve American citizens and consumers in a consistent, reliable, and affordable manner.

The Propane Delivery Infrastructure is Undergoing a Dramatic Transition

The delivery infrastructure for fossil fuels — petroleum, natural gas, and natural gas liquids, of which propane is one — is in the midst of an historic transition, which has exacerbated propane supply and delivery challenges this winter heating season. Historically, propane has been produced in the Gulf Coast and the Mid-continent and then transported to consuming regions to the North and East, primarily by pipeline. During the summer, when propane demand is typically low, propane was placed into seasonal storage, primarily in the storage facilities in the Gulf Coast and Kansas. During the winter, propane was withdrawn from storage and shipped by pipeline, rail, and truck to consumer markets. In addition, the Northeast previously imported significant volumes of propane by marine tanker, particularly during the winter.

Over the last six years, the nation's exploration and production community has devoted enormous resources to finding and extracting fossil fuels from shale formations, all of which had previously been beyond economic reach. The result has been the production of previously unimaginable amounts of domestic fuels, including propane. One of the challenges, however, has been that this production has occurred in different areas from those where the nation has previously produced its energy supplies. These include, for example, the Marcellus and Utica formations (Pennsylvania and Ohio), the Bakken formation (North Dakota), and the Fayetteville formation (Arkansas).

The result has been a change in the historical flow of fuels. The nation's energy infrastructure was built to deliver petroleum, natural gas, and natural gas liquids from Texas, Louisiana and Oklahoma to markets throughout the country. With the influx of energy from shale formations, the nation's energy delivery system has had to make significant adjustments. New infrastructure is being built to bring Bakken crude to market. Natural gas and natural gas liquids are now flowing from the Marcellus both toward Northeast markets and the traditional energy-producing markets of the Gulf Coast. Several petroleum products pipelines are being reversed to transport product toward areas that have traditionally been energy-producing. Natural gas pipelines are being converted to carry petroleum. Propane pipelines that have been underutilized in the past, or used primarily to meet winter demand, are being converted to carry production from the new producing regions to the processing facilities in the Gulf Coast or Canada. Rail carriers and motor carriers are being enlisted to transport products to make up for pipeline infrastructure that has not yet been built.

Additionally, as shipments of heavy crude oil from Canada have increased, demand for diluent, a substance necessary for the processing and pipeline shipment of heavy crude, has increased. Northbound pipelines are increasingly targeting this demand, offering priority service and incentive rates to diluent producers in the Gulf Coast for shipments north to Canadian producing regions. As diluent shipments have increased, the available capacity for northbound shipments of traditional products, including propane, has been reduced.

These events have been disruptive to energy infrastructure and energy markets. The transition is, however, nowhere near complete. The challenges that have occurred for propane markets during the 2013/2014 winter have been exacerbated by this transformation of the energy delivery infrastructure.

Cochin Pipeline Reversal

One of the pipelines undergoing transition that most significantly affects Midwest propane delivery is the Cochin Pipeline. The Cochin pipeline system consists of an approximately 1,900-mile, 12-inch diameter multi-product pipeline operating between Fort Saskatchewan, Alberta, and Windsor, Ontario, including five terminals in the U.S. located at Carrington, N.D.; Benson and Mankato, Minnesota; New Hampton, Iowa; and Milford, Indiana. The pipeline is currently capable of transporting 50,000 barrels of propane a day from Alberta into the U.S. Midwest and Ontario.

Historically, the Cochin pipeline has been a major source of propane into the upper Midwest, and about 40 percent of propane in Minnesota came via the Cochin pipeline. However, for approximately three starting in late November 2013, the Cochin pipeline was not in operation. This unfortunate situation made it nearly impossible for propane storage levels in the region to be replenished after the record-breaking crop drying season that saw a nearly six-fold increase in demand for propane. The Cochin pipeline is currently scheduled to permanently halt all propane transportation in April of this year. The owner of the Cochin Pipeline, Kinder Morgan, is planning to convert the Cochin Pipeline to carry diluent from the U.S. shale plays to the oil sands producers in Canada.

ATEX Pipeline Reversal

The Appalachian-Texas Pipeline (ATEX) is a new provider of ethane service from the Marcellus region to the Gulf Coast. The pipeline itself is not new, however; rather it is one of two parallel pipelines that run from Mt. Belvieu, Texas to Todhunter, Ohio. What is new is that the ATEX pipeline used to deliver product batches northward as part of the Enterprise TEPPCO system. The decision to reverse this pipeline to take ethane southward reflects the economics associated with taking the huge increases in shale production of natural gas liquids to market. Unfortunately, this reversal has caused all northbound product flowing on the Enterprise TEPPCO pipeline to be squeezed onto the remaining northbound pipeline. The elimination of this northbound capacity, along with the introduction of priority diluent service on the remaining northbound line to assist in the processing of Canadian heavy crude oil, has caused congestion and delays for shipments of propane to the Midwest and northeast.

Borger-Denver Pipeline Reversal

Only last week we learned that the Borger-Denver Pipeline, which runs from Texas through Missouri into Illinois, will be reversing its flow in the near future. In prior years it has regularly done so in the summer (i.e., July), but is now advancing it by a month to March. The result is that the Jefferson City, Missouri terminal is now empty, and that no more propane will be flowing over the pipe this winter into the St. Louis area and downstate Illinois.

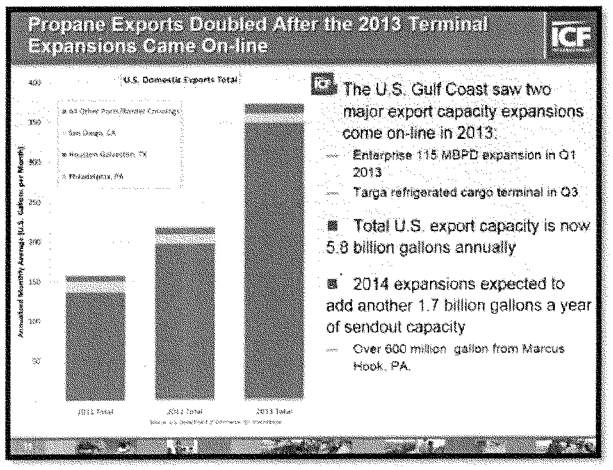
Rail Transportation

Significant volumes of propane are shipped via railroad, and the propane industry is increasingly reliant upon this transportation mode. Here too, however, competition from other substances for transportation is intense and growing. Many facilities producing natural gas liquids, crude oil, or any of a variety of other products have yet to have access to reliable pipeline service to take their products to market, so they rely on railroads. Some of these products use the same kind of railcars as propane, which places additional demands on the existing pressurized railcar fleet. For those products that don't use the same kind of railcars, additional usage of the railroad infrastructure increases congestion making service less reliable even when railroads desire to prioritize propane shipments.

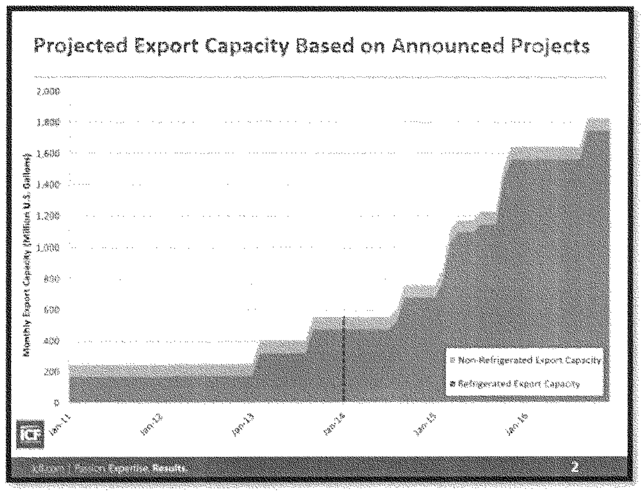
Dramatically Increased Propane Exports Have Changed Market Dynamics

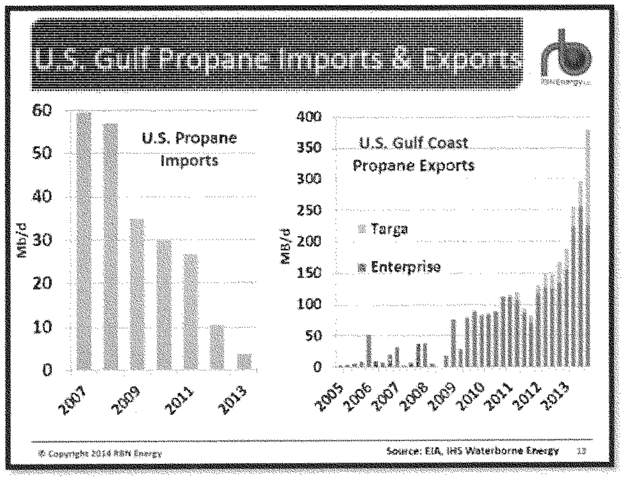
The fact that America is now considering revising its energy policies to foster exports of natural gas and crude oil shows just how dramatically the shale revolution has turned the supply situation on its head. Unlike crude and natural gas, propane is not subject to any existing export prohibitions or licensing requirements, so exports have increased as fast as contracts could be signed and export capacity developed.

In 2013, U.S. propane production increased by 1.5 billion gallons. However, propane exports increased by 2.0 billion gallons, from 2.6 billion gallons in 2012 to 4.6 billion gallons in 2013. Last year, exports grew to over 20 percent of total U.S. propane production, and they are still increasing. There is no question that exports in such significant volumes were a significant factor during the winter of 2013/2014.



There are a number of factors driving propane exports. Propane is a global commodity, and it is easily shipped. High production levels of natural gas and natural gas liquids depressed prices in the U.S., creating a differential making international shipments attractive. Strong demand from buyers in Central and Latin America, as well as Asia, looking for relatively cheap propane and willing to sign relatively long-term contracts – up to 10 years in duration -- provided an incentive to ship propane overseas. The contracts for these export facilities are designed to ensure a very high utilization rate, with penalty payments incurred if export shipments are cancelled. American companies looking to serve this market invested heavily in constructing or upgrading export facilities. The trend of increasing exports shows no sign of easing. Announced plans to construct additional propane export capacity would triple propane export capacity in the next three years.





This graph shows the countervailing changes in the flow of propane into and out of the United States since 2005.

Causes and Contributing Factors of Tight Supplies in the Winter of 2013/2014

Pre-Season Inventory Levels

The 2013/2014 heating season began with national propane inventories at approximately 67 million barrels, eight million barrels less than at the same time in 2012. Traditionally, the winter heating season starts the first week in October when the U.S. Energy Information Administration (EIA) begins publishing its "Heating Oil and Propane Update," which is published weekly during the heating season each year. In 2013, national propane inventories were roughly in the middle of the 5-year average as reported by EIA.

While we entered the heating season with average inventory levels, between October 2013 and January 2014 total U.S. propane consumption increased by about 570 million gallons relative to the same period in the previous year. In the Midwest, propane consumption from October 2013 to January 2014 increased by 410 million gallons (9.8 million barrels) relative to the same period in the previous year. In the Northeast, propane consumption increased over the 2012/2013 winter levels (to January) by an estimated 52 million gallons (1.2 million barrels), while the South saw an estimated increase of 122 million gallons (2.9 million barrels). The only region of the country to have seen a drop in propane consumption is the West, where the dry, warm winter is estimated to have caused a decline in estimated propane consumption of 21 million gallons (0.5 million barrels).

During the week ending February 14, 2014, PADD 2 (Petroleum Administration for Defense District - Midwest) inventories were below the 5-year minimum level and threatened to reach the 10-year low reached in Mid-March 2008. PADD 2 inventories are now below the 10-year minimum level. PADD 3 (Gulf Coast) inventories are also approaching the 10-year minimum level. As of February 14, 2014, (reported by the EIA on February 21, 2014), U.S. propane/propylene stocks had fallen by 1.2 million barrels week on week to 26.7 million barrels, 24.4 million barrels (47.7%) lower than a year ago.

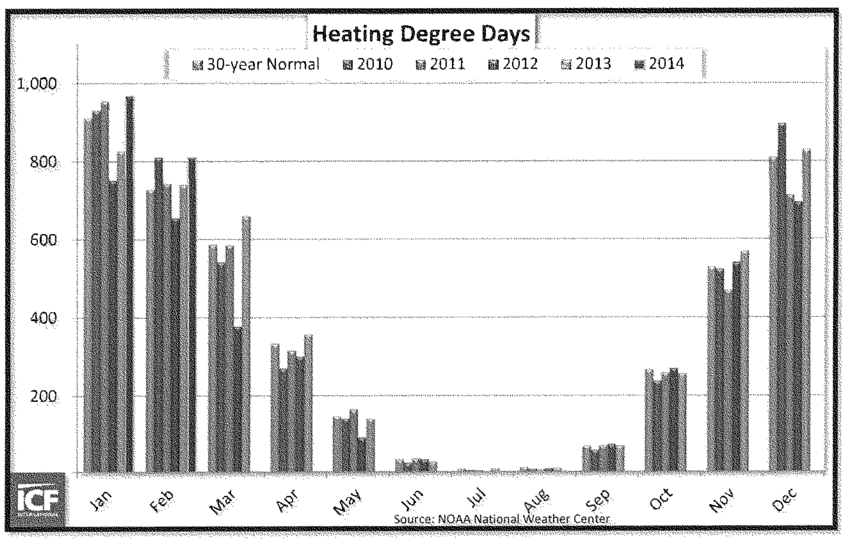
Crop Drying Demand

A primary factor leading to low inventories, particularly in the Midwest, was an unusually wet and large harvest that occurred late in the harvest season forcing farmers to use more propane than anticipated. During the 2013 corn harvest, about 13.9 billion bushels of corn were harvested, a historic record. During the same time, the "Corn Belt" region of the Midwest received above-average rainfall, with the first week of October recording 200 to 500 percent above normal precipitation. Industry analysts estimate total grain-drying demand for propane at more than 300 million gallons in 2013, 235 million gallons above 2012 levels. These factors led to an increased demand for propane late in the harvest season. Compounding this situation was the fact that the harvest was compressed into a much shorter period of time than usual. Suppliers in the Midwest did not have the chance to rebuild propane inventories before the onset of an early and cold winter.

Colder Than Normal Weather

With propane supplies already low due to the dramatic increase in agricultural consumption, many propane retailers were undersupplied when the pace of winter home-heating demands rose quickly and significantly. Additionally, consumers in many instances were underprepared for the early, intense winter characterized most notably by the "Polar Vortex" weather phenomenon. The intensity level of winter was particularly unexpected, considering the unseasonably warm winters of the previous two years.

When comparing Heating Degree Days (HDD)[1] to the previous three years, this winter's U.S. total population weighted HDDs through January come in 3.1% above NOAA's 30-year average, 10.1% above the 2012/2013 season, and 15% above the 2011/2012 season. Not only was this winter above historical norms, but heating needs compared to last year's equates to an increased propane demand of 640 million gallons in 2013 relative to 2012, and an increase in propane demand of about 300 million gallons for the October 2013-January 2014 period relative to the previous winter.



State and federal authorities helped alleviate the situation

[1] According to the EIA, **Heating Degree Days (HDD)** provide "A measure of how cold a location is over a period of time relative to a base temperature, most commonly specified as 65 degrees Fahrenheit. The measure is computed for each day by subtracting the average of the day's high and low temperatures from the base temperature (65 degrees), with negative values set equal to zero. Each day's heating degree days are summed to create a heating degree day measure for a specified reference period. Heating degree days are used in energy analysis as an indicator of space heating energy requirements or use."

Many people contributed to resolving, and are still working to resolve, the issues posed by this year's heating season. On behalf of the industry and our customers, NPGA wishes to thank these individuals and organizations for their commitment to finding both short-term and long-term solutions.

Many states have granted Hours of Service (HOS) waivers, which have helped immensely. These waivers allow truck drivers to obtain needed propane from far-away places and deliver that propane to customers. On the federal level, the Department of Transportation (DOT) granted four unprecedented regional waivers from HOS. As many as 35 states in the FMCSA's Eastern, Midwestern, Southern, and Western Service Centers were granted these exemptions, providing stability and uniformity throughout these regions. Exemptions in portions of the Eastern, Midwestern and Western Service Centers remain in effect through March 15.

Some of the states have also granted exemptions from weight limits for trucks traveling over state roads. While this does not allow drivers to carry overweight loads on interstate highways, it does help trucks carry additional fuel volumes up to the maximum amount of propane allowed by law even though the vehicle was overweight.

The State of Texas deserves specific recognition for its efforts, which were crucial in getting propane supplies out of the state to the rest of the country. Texas is host to the largest primary storage of propane in the world, and many truck drivers from out of state traveled to Texas to obtain the fuel directly from the storage facilities near Mont Belvieu. Specifically, the state waived its permitting requirements for out-of-state vehicles, a process that can otherwise take as much as 30 days to complete. This allowed drivers from other states to immediately operate in Texas so they could transport their load back to their home state.

A number of states have taken advantage of the Low-Income Home Energy Assistance Program (LIHEAP) to help consumers. At a time when we've seen unusually high prices, this program has provided much needed assistance to the customers who need it most.

Energy Secretary Ernie Moniz was personally active in asking pipeline companies to prioritize shipments of propane on their systems. He also reached out to several NPGA members to determine what further assistance DOE could provide. DOE's Office of Electric Delivery and Energy Reliability has been helpful and supportive throughout the winter by holding conference calls, on a daily basis at times, with NPGA and other industry stakeholders to address the infrastructure and delivery concerns.

The Federal Energy Regulation Commission (FERC) invoked, for the first time in its history, emergency authority requiring the operator of the Enterprise TEPPCO pipeline to prioritize shipments of propane. This action ensured that an additional 500,000 barrels of propane would move from Texas up into the Midwest and Northeast earlier than regularly scheduled.

The Small Business Administration (SBA), through its individual state offices and loan partners, provided relief in the form of Express Loans and Micro Loans to propane retailers. These loans provided relief to the small propane marketers who, due to the increased cost of propane from their suppliers and the increased volume of propane required, had reached the limits on their existing lines of credit.

Finally, we are also grateful for the meetings with the Governors of the affected states, and the numerous teleconferences with states' energy, transportation, and agriculture officials that were held, which allowed the sharing of credible real-time information and increased coordination among all parties.

Recommendations to Improve Propane Reliability, Resilience and Consumer Protection

Propane markets in the United States are not regulated except as to issues of safety. Neither the federal nor state governments exercise economic regulation (except as to pipeline transmission), as the market is characterized by intense free market competition and low barriers to entry. Nevertheless, given the experiences of the winter of 2013/2014 it is evident that there are roles for government to play to ensure reliability, resilience, and consumer protection. NPGA has now launched a broad-based effort with its membership to assess the lessons learned from this winter to determine what action government might take to avoid a future recurrence. Nevertheless, a few areas for government action are already clear, and they are outlined below.

Review Export Policies

During the winter of 2013/2014, as supply constraints emerged and as prices spiked, many consumers and members of the propane industry questioned whether these events were caused by the growing exports of propane. Over the past four years, as explained above, exports of propane from the Gulf Coast have increased dramatically as new export capacity has been developed and brought online. Based on the number of additional projects designed to increase export capacity that are currently under construction or have been announced, this growth trend is expected to continue. NPGA has already commissioned a study to examine the propane export question. Further in-depth analysis is, however, needed, and NPGA will request that the EIA conduct a study of propane supply, demand, and exports similar to the study it conducted with respect to Liquefied Natural Gas (LNG) exports.

Should policy action with regard to exports be deemed necessary, there are a variety of broad options to be considered. Some have suggested that Section 3 of the federal Natural Gas Act of 1938 would empower the federal government to require export licenses. This is unlikely, as it has never been suggested over the last seventy-five years that this statute applies to propane. Another avenue would be a provision of the Energy Policy and Conservation Act of 1975 found at 42 U.S.C. §6212. Arguably, this authorizes the President to control propane exports. Such control might include licensing turning upon a public interest finding, export restrictions tied to prices or demand, or outright prohibition of exports. (NPGA understands that the President's authority under this law has been delegated to the Secretary of Commerce.) This authority has not been invoked in the past, and a formal proceeding engaging all stakeholders would, by the terms of the statute, be necessary. Congress, of course, also has plenary authority to enact a new law that addresses this issue in any fashion that it determines to be in the interest of the United States. Should the federal government move forward on this front, it would be necessary to ensure that any policy adopted is compliant with World Trade Organization principles and the various trade treaties to which the United States is a signatory.

Ensure Markets are Performing Properly

In January 2014, wholesale prices of propane at a market hub in the Midwest tripled in the matter of a few days. This caused a temporary doubling of retail prices in large areas of the Midwest as reported by the Department of Energy (DOE). While price fluctuations in winter are common as supply and demand balances are achieved, these dramatic increases in propane prices were unprecedented.

On January 23, 2014, Senator Charles Grassley called on the Federal Trade Commission (FTC) to investigate the matter to ensure that these price spikes were not a result of anti-competitive behavior or illegal manipulation. NPGA fully supports Senator Grassley's request and urges the FTC to review the matter expeditiously and thoroughly.

NPGA believes it is an appropriate role of the federal government to assure citizens that markets are operating lawfully and to take appropriate action if they are not. While significant price volatility is common with respect to almost all energy commodities—and is in fact necessary to allow markets to function appropriately—it is important to ensure that unexpected volatility such as that observed this winter was in fact caused by the appropriate functioning of energy markets rather than anti-competitive behavior or market manipulation. Additionally, there may be roles for other federal agencies to play in ensuring that propane production, transmission, and marketing have occurred, and will occur, consistent with free-market principles.

Improve Inventory Data – Timeliness and Reliability

EIA maintains a number of data gathering programs in the energy area and publishes weekly inventory numbers and trends for propane, among other fuels. EIA data includes weekly residential and wholesale propane prices; propane stocks in barrels and days of supply; regional propane production and imports; and propane demand estimates. Unfortunately, EIA data has not kept pace with changes in the energy sector, particularly with regard to the shale revolution and production of natural gas liquids, such as propane.

Such high levels of production have provided incentives for companies to export significant volumes of propane to such an extent that the U.S. is now the world's largest exporter of propane. Propane export data is available on a per-ship basis by subscription from costly private sources. It would be highly useful to the industry and the public for EIA to expand its data gathering activities to include regular publication of aggregated propane export data. This would provide industry and policymakers with clear knowledge of the trends in propane exports, making appropriate business decision-making more rational and timely.

Significant volumes of propane are owned and stored at proprietary terminals or locations around the United States. The location, size, contract status, and accessibility of these inventories are unknown, which puts the marketplace in a vulnerable position when supplies get tight. In previous years, the petrochemical sector sold propane back into the marketplace when prices rose in response to tight supplies, which performed a balancing role to bring prices back down. The shale revolution has changed this dynamic and greatly increased the complexity of the relationships among the various natural gas liquids uses and marketplaces. Nevertheless, the fact remains that volumes of propane are stored in proprietary storage facilities in amounts completely unknown to the marketplace. In addition, an unknown quantity of the propane in the available propane inventory reports is committed to exports, and would not be available to the domestic market without paying significant contractual penalties. As a result, the reported propane inventory data overstates inventories that are actually available to the domestic market, and no one knows how big this overstatement might be.

This winter, volumes at Conway, Kansas, approached critically low levels and NPGA was concerned this could lead to significant deliverability problems. NPGA had no way of knowing how low volumes were going to be in part because of the lack of knowledge about proprietary storage levels. When the marketplace does not have good data about supply, prices are affected; this winter was no exception. In the future it would be very helpful to have a better handle on proprietary storage levels, as this would mitigate price spikes, like those seen this winter.

Beginning approximately ten years ago, EIA began collecting and publishing weekly natural gas storage data. There is no question that this data is a key information point that is reviewed and considered by many decision makers in the natural gas industry. The weekly storage report is a key piece of market data for both spot and futures natural gas markets. It also assists in ensuring market transparency and a well-functioning market. A similar data set by EIA would be of great assistance to propane market participants and would assist in ensuring transparency of markets.

The data that EIA currently collects lumps both propane and propylene together. Disaggregating these two commodities would aid in market transparency. Similarly, additional geographical granularity in propane inventory data would be welcomed by markets.

Increase Transparency in Petroleum Products Pipelines

There has been significant consolidation in the interstate pipeline system regarding propane. Currently, the three largest interstate propane pipelines are owned or controlled by a single company. In a presentation to FERC in July 2013, NPGA presented data estimating the propane deliveries on the key multi-shipper propane pipelines. Of these, a single company shipped approximately 80 percent of propane, while all the others shipped approximately 20 percent. At the same time, there have been significant rate increases proposed on the federally regulated Dixie and TEPPCO pipelines, while the costs for other non-regulated terminalling services have increased as well.

From discussions with NPGA members over the past several months it is apparent that the operation this winter of the nation's petroleum products pipelines—the principal means by which propane is delivered to the market—is at best opaque, and the lack of transparency substantially increased the difficulty of dealing with the propane supply shortages. For example, propane shippers report being unable to obtain capacity on pipelines to deliver product to markets with critical needs while the owner of the pipeline has product available for sale in those markets.

While this opacity may have served a purpose in the past, at this point it may give an undue advantage to a pipeline that is also engaged in selling, marketing, or trading propane. A legislative fix may be needed. In the same vein, the manner in which pipelines operate without providing adequate information to the marketplace in a transparent and timely manner does not allow the market, including propane companies, to respond adequately and adapt to changes in pipeline operations. Rather, it gives an undue advantage to the pipelines, especially those with marketing and other business operations outside the transportation area.

Additionally, the Federal Energy Regulatory Commission (FERC) should increase its oversight of infrastructure changes that have significant impacts on customers, especially when the pipeline industry is becoming more concentrated both vertically and horizontally and when assets that have been dedicated to and paid for by historic shippers such as propane shippers are spun off into unregulated ventures. There are several aspects to this issue. Remedies may require revisions to the Interstate Commerce Act or to policies of the FERC, which regulates interstate petroleum products pipelines under the Interstate Commerce Act.

Enact Pipeline Affiliate Rules

FERC has previously adopted rules that apply to natural gas pipelines and electric transmission systems that govern the relationship with their affiliates, referred to as "affiliate rules" or "codes of conduct". The fundamental purpose of these rules is to prevent the pipeline or electric transmission provider from utilizing its transmission function—which is a regulated monopoly function—to benefit its affiliates that are market participants, usually energy marketers and traders.

These rules do not apply to petroleum products pipelines, including those that transport propane. Some of these pipeline operators are involved in selling propane, trading in propane, and exporting propane, among other things. NPGA is concerned, particularly after the challenging winter market conditions, that these intra-corporate relationships may have been utilized to the detriment of the interests of consumers. NPGA will be requesting that FERC adopt rules for petroleum product pipelines that are similar to those for natural gas pipelines and electric transmission providers.

In addition, pipelines have been removing certain terminal and storage assets from jurisdictional service and transferring these facilities to unregulated affiliates. The unregulated affiliates then are able to charge dramatically higher prices for the same services. The FERC has allowed these conversions to non-jurisdictional service based on an overly narrow definition of interstate transportation.

NPGA will be requesting that FERC adopt rules for petroleum product pipelines that are similar to those for natural gas pipelines and electric transmission providers. In certain areas, this may also require legislative action.

Review Pipeline Allocation and Information Rules

Throughout the Midwest, Northeast, and South during this winter petroleum products pipelines have been severely constrained as to capacity. Market participants desired to transport propane to markets with critical needs, but the capacity was not available to do so. On many of the pipelines relied on by the propane industry, propane is only one of many products shipped by the pipelines. During pipeline capacity shortages, the pipelines allocate capacity based on summer pipeline usage. Currently, this capacity cannot be assigned to a different party.

According to Section 6 of the TEPPCO LPG pipeline tariff proration policy, which is similar to others in the industry:

> In no event will a capacity allocation to a LPG Shipper be used in such a manner that will enhance the allocated capacity of another LPG Shipper beyond the allocated capacity that such LPG Shipper would be entitled to under this Policy. Carrier may require written assurances from a responsible officer of LPG Shipper regarding its use of its allocated capacity stating that LPG Shipper has not violated this Policy. In the event any LPG Shipper shall, by any device, scheme or arrangement whatsoever, attempt to transfer all or any part of its allocated capacity to any other LPG Shipper in violation of this Policy, or in the event any LPG Shipper shall attempt to receive and use such portion of capacity, the portion of capacity allocated to each such LPG Shipper will be reduced in the next Allocation Period after the date that the violation is discovered by a volume equal to two times such attempted transfer.

In addition, under current rules, certain customer information, including shipper and volume information cannot be disclosed by the pipelines, making it impossible to determine who is shipping on the pipeline.

Such provisions prevent shippers of lower-value commodities or shippers with sufficient storage to meet near term requirements from releasing their pipeline capacity to shippers of high-value commodities, such as propane in the winter season, even though it might be to the economic advantage of both to do so. As a result, this winter propane shippers were unable to negotiate deals with shippers of other products such as diluents headed to the Canadian oil sands producers to increase propane shipments and reduce shipments of other products.

As this became apparent, FERC recognized the need to meet the essential needs of consumers and employed its emergency authority under the Interstate Commerce Act for the first time to ensure that an additional five hundred thousand barrels of propane were moved to Midwest and Northeast markets. NPGA commends FERC for its prompt action. Going forward, however, there may be other mechanisms to avert a recurrence. Certainly, affiliate rules, mentioned above, will give market participants confidence that the market is functioning in an above-board manner. In addition, FERC may be able to adopt mechanisms from other areas of its regulatory portfolio, including natural gas pipelines in order to ensure that market mechanisms are available to resolve pipeline allocation issues, instead of relying on emergency orders from FERC.

NPGA will be requesting that FERC adopt rules for petroleum product pipelines that are similar to those for natural gas pipelines and electric transmission providers. In certain areas, this may also require legislative action.

Revise Thresholds for the Use of Federal Emergency Authority

NPGA has worked closely with a number of federal agencies that maintain oversight over the supply, transportation, and distribution segments of the propane industry to obtain relief from their applicable regulations. However, NPGA believes revisions to the thresholds for triggering an agency's emergency authority would permit greater flexibility in addressing supply and infrastructure issues in the future. NPGA has identified several areas where the limited authority of the Department of Transportation (DOT) and DOE hampered their efforts to facilitate a rapid response to the evolving supply, transportation, and distribution crisis. Congress should review and revise these impediments to prompt action.

1. The Robert T. Stafford Act (P.L. 93-288, as amended)

The Stafford Act establishes the criteria under which the federal government responds to significant emergencies. An emergency declaration can only be requested of the President by the governors of the affected states. When requested, the Federal Emergency Management Agency performs an analysis to determine if the declaration is needed. If an emergency is declared, states must share a portion of the costs. Despite the severity of the propane situation this winter, this "all or nothing" aspect of a Stafford Act determination proved too high a threshold for state governors to embrace, and it foreclosed needed assistance to propane retailers and their consumers.

Among the many actions taken by NPGA this winter, it sought a waiver of the federal weight limits for trucks hauling propane on interstate highways. These limits are established by the DOT's Federal Highway Administration (FHWA). The purpose of the NPGA request was to allow trucks to load propane to the maximum permitted filling capacity of the truck. Due to highway weight restrictions, these trucks could only fill to within about fifteen to twenty percent of the maximum permitted level, essentially leaving the filling terminals with about 1200 to 1400 gallons less than they could carry with a waiver in place.

The FHWA has no statutory authority to grant a waiver from the weight restriction regulations. Unfortunately, the only mechanism by which a waiver could be granted would be for the President to declare an emergency using the authority provided him under the Stafford Act. Yet, as mentioned above, governors were unwilling to invoke the Stafford Act to lift weight restrictions given the other costs of doing so. Given the nature of the fuel emergency that existed, NPGA strongly supports amending the Stafford Act to provide for more limited waiver authority. Specifically, the Secretary of Transportation, perhaps in consultation with the Secretary of Energy and Governors, should have the authority to grant a waiver from the weight restrictions, either under the Stafford Act or under other legislation. This narrow action would go a long way toward ameliorating a fuel emergency or disaster without all of the complications and costs of a full-fledged Presidential emergency declaration.

2. The Jones Act

The Jones Act requires that all maritime shipments of any kind between U.S. ports (in the "coastwise trade") be aboard U.S.-flagged vessels. In our case, a marine shipment of propane from a port on the Texas Gulf Coast (PADD 3) to ports in New England (PADD 1a), for example, would have to be aboard a U.S.-flagged vessel. The challenge in meeting this requirement is that there are currently no U.S.-flagged ships available to carry propane, leaving American consumers literally out in the cold.

Waterborne transport has the potential to be a critical component in addressing the overall supply and distribution challenges facing the propane industry in the Northeast. A shipment of American propane from Texas, where the world's largest underground propane storage is located, to New England would have made a significant impact on the supply issues in that region of the country, and also would have freed up transportation assets, including pipeline capacity and rail cars to deliver propane into the Midwest and other regions of the country. However, given propane production trends, a ship capable of transporting propane from the Gulf Coast to the Northeast likely would be utilized only a few times each year, and in some years, such as 2011/2012, would not be utilized at all.

Unfortunately, obtaining a waiver from the Jones Act is generally acknowledged to be nearly impossible. In order to obtain a waiver, the request must be made to the Department of Homeland Security's (DHS) Customs and Border Protection (CBP) agency. Once a waiver request is received, CBP consults with the DOT's Maritime Administration (MARAD) to determine if a U.S. ship is available. CBP also consults with DOE to assess the energy and fuels supply situation. This review and consultation is a time-consuming and arduous process.

During the last several months, NPGA has been engaged with DOE on propane supply and distribution matters at a frequency of at least three times a week, if not daily. DOE had the greatest knowledge of the state of the industry supply and would have been best positioned to grant a waiver from the Jones Act for a *de minimis* period of time. NPGA believes that in the context of fuel emergencies DOE should be given the authority to grant such waivers from the Jones Act.

3. Hours of Service

The DOT Federal Motor Carrier Safety Administration (FMCSA) establishes Hours of Service (HOS) regulations that specify the number of hours that truck drivers may drive a commercial motor vehicle and that they may be on-duty. The HOS regulations were changed in 2013. The most significant change for long-haul drivers in the propane industry pertained to the "34-hour restart" provision. This provision permits drivers to "restart" their driving service if they have been off-duty and have not driven for 34 consecutive hours. Most importantly, FMCSA 2013 change required that the 34-hour period must also include two 1 a.m.-to-5 a.m. off-duty periods, in contrast to the previous requirement, which permitted 34 consecutive hours off duty. NPGA believes that the 2013 change resulted in a reduction of productivity of up to fifteen percent. During the 2013/2014 winter, this loss in productivity reduced the amount of fuel delivered.

NPGA believes that the 2013 change resulted in no additional increment of safety, but this winter it resulted in a detriment to propane consumers.

During the height of the winter supply and distribution issues, FMCSA did issue regional waivers from HOS regulations for the Eastern, Midwestern, Southern and Western Service regions, which waived the 34-hour restart requirement and expedited propane shipments. Nevertheless, NPGA believes there is no evidence to suggest there is a reduction in safety by reverting to the previous requirement of 34 consecutive hours off duty (as opposed to requiring two 1 am to 5 am periods), and we would recommend the reinstatement of the previous regulatory requirement.

Expedite Increases in Storage Infrastructure

If there is one lesson learned from the 2013/2014 winter propane market conditions, it is that the infrastructure network was inadequate to meet consumer needs. There are a number of facets to this, and government can assist in ensuring that essential human needs are met.

Underground Storage

Since 2009 NPGA has argued that permitting and constructing expanded underground propane storage in the Finger Lakes area near Reading, NY is essential to meeting Northeast propane needs. We have called on Governor Cuomo to approve the facility, which would add over 88 million gallons of propane storage in a region where demand far exceeds local supplies. New

Yorkers, and the entire New England region in general, are highly dependent on propane shipments from outside the region. New York is at the tail end of the TEPPCO pipeline, which delivers propane from major primary storage facilities in Mt. Belvieu, Texas. As discussed above, TEPPCO recently reversed part of its line to deliver ethane south to the Gulf Coast from the Marcellus-Utica Shale regions. This has inhibited the pipeline's capacity to deliver propane supply to New York.

We have seen a number of challenges confronting the propane supply chain, ranging from pipeline shutdowns to rail strikes in Canada to ships not coming in on time from overseas. Supply lines can and do break during the winter, and they have caused shortages in the past. This winter, propane marketers have found themselves needing to drive long distances to obtain supply. Drivers have obtained supply from destinations as far away as Apex, North Carolina, and Sarnia, Ontario. Having additional secure propane storage in New York would help ensure that fuel is available nearby. The propane industry is proposing to address these issues in a responsible way through initiatives like the Finger Lakes storage facility.

It is important to note that the mix of fuels used in New York is changing, and many fuel oil customers are shifting to cleaner-burning propane. It is cleaner in the house, and it is cleaner for the environment when it is consumed. As the propane industry expands in New England, we need to be able to store adequate supplies of propane reasonably close to serve these new customers.

Approval of the Finger Lakes facility will also improve the resilience of the propane infrastructure in the southeast and Midwest regions of the United States. In recent weeks, a major propane storage facility in Sarnia, Ontario, has seen very high demand due to its close proximity to both the New England and upper Midwest regions. Sarnia storage is now quite low, which compounds other low storage in Michigan and surrounding states. Similarly, the propane storage facility in Apex, North Carolina, has been supplying significant volumes into New York and New England. Earlier this winter we understood that the Apex facility was practically empty, which had implications for the Southeast. Were the Finger Lakes facility to be in operation, it would dramatically reduce New York's demand for propane stored in Sarnia and Apex. Approval of Finger Lakes would have cascading benefits far beyond New York and New England.

Agriculture Storage Incentives

Unexpected demand by the record-setting crop-drying season caused a significant draw-down of propane supplies, particularly in the upper Midwest. This caused propane inventories to be lower than nominal as a colder-than-normal winter swept in. Storage at agricultural facilities is not particularly significant, requiring marketers to make multiple trips to some facilities sometimes as often as daily in the event of a large harvest. This experience has highlighted the significant impact that minimal storage at agricultural sites can have on the overall propane infrastructure, so we support incentives for farmers and crop dryers to increase their on-site storage capability. Such increased storage would have multiple benefits, including resilience in the face of unexpected demand; reducing the frequency marketers need to fill the storage; and more closely matching the capabilities of the crop drying equipment itself.

Permitting and Siting

Adequate propane storage at the tertiary (customer) level is critical as we enter the crop drying and heating seasons. Unfortunately, it is sometimes difficult to expand the propane storage infrastructure in the face of local opposition. Propane storage is highly regulated through building and fire codes, and the engineering of systems is standardized to a significant degree. The propane industry works closely with state and local officials to ensure a comfort level with propane storage, and this is an ongoing process. It is critical for state and local officials to allow propane storage to be built, maintained and expanded, so that the growing customer base of propane consumers can be served safely and efficiently.

Assessing Industry Practices and Opportunities for Industry Education

The difficulty in meeting unexpected propane demand efficiently this winter can in part be attributed to industry business practices that have taken hold in response to shifts in market conditions over the last 20 years. Consumer propane sales have fallen by more than 24 percent between 2000 and 2010. Moreover, retail propane jobs fell by more than 20 percent during the same period. This has been the result of a number of factors, including competition from other energy sources, as well as improvements in appliance and building efficiency.

Consumer education plays a role in lessening the risk of supply shortage. NPGA believes it is critical for consumers to build a relationship with a local propane supplier and to buy their fuel well in advance.

Propane customers typically fall into two categories: "keep full" customers, those who enter into a contractual agreement with a propane retailer to keep their tanks full; and "will call" customers, those who choose not to enter into a contract with a retailer and instead choose to buy their propane supply on their own. The "keep full" customer benefits from the security that their energy needs will be met, and retailers benefit from the certainty of being able to plan ahead for their customers' fuel needs. "Will call" customers must manage their own supply level, price shop for fuel, and ensure their system is in proper working order. "Will call" customers typically have a lower priority compared to "keep full" customers when system demands are high. Such customers are much more vulnerable to market variability and supply disruptions – like the ones resulting from this winter's supply, demand, and infrastructure challenges. NPGA will redouble its efforts to encourage consumers to build a relationship with a retailer in their area to make sure that their energy needs are met.

Many consumers can also fill their tanks in the summer, planning ahead for winter heating. This can also have the added benefit of lower off-season propane prices. Unfortunately, many propane customers are unable to afford to tie up their available cash by refilling their tanks during the summer. For these customers, one additional way to increase certainty of propane supply in the winter heating months is for customers to enroll in a budget plan with their marketer. This allows the costs of fuel to be spread over the entire year, making it more affordable than paying for a full tank all at once.

Conclusion

As we analyze the causes of the problems encountered during the winter of 2013/2014, NPGA's goal is to ensure that such a situation never happens again. NPGA has established a Supply and Infrastructure Task Force charged with conducting a comprehensive post-winter analysis to identify causes and contributing factors, and analyze, debate, and provide recommendations to the NPGA Executive Committee for future efforts and strategy as it relates to propane supply, distribution and infrastructure. We intend to pursue the Task Force's policies and recommendations aggressively, and we anticipate that our efforts will focus on public policies, industry operations and practices, and consumer needs. We look forward to keeping you informed of our progress as we move forward.

NPGA and its member appreciate the opportunity to present their perspective on these important issues to the Committee.

Thank you.

A Propane Primer

Propane is a naturally occurring hydrocarbon commonly found in the production stream of oil and natural gas wells. With the chemical formula C_3H_8, it is one of the least complex hydrocarbons (technically an alkane). It is closely related to methane (natural gas), which, with the chemical formula CH_4, is the least complex of the hydrocarbons. Chemically, only ethane (C_2H_6) separates natural gas and propane. More complex hydrocarbons include butane, pentane, hexane, and octane. The molecular proximity of propane to methane has important real-world consequences, as we will discuss below.

Like natural gas, propane is colorless, odorless, and tasteless. (For both products the smell that people associate with them is artificially added at the retail level.) Both are gaseous at normal temperatures and pressures. As a result, both are readily usable as fuels in a number of applications. While natural gas liquefies at -162 Centigrade, propane liquefies at -42 Centigrade. With pressure, propane becomes a liquid at somewhat higher temperatures—hence "liquefied petroleum gas" (LPG), another name for propane. An important consequence of the difference in the temperatures at which the two compounds liquefy is that propane can be stored and transported in relatively lightweight containers and with much greater ease and economy than natural gas (in either a gaseous or liquefied state). While large volumes of propane are transported by petroleum products pipelines, it is also commercially feasible to transport it by rail, truck, ship, and barge. Technically those modes are possible for natural gas, but they are not generally economically feasible—on a retail basis—because natural gas, whether compressed or liquefied, requires much heavier storage containers and higher pressure or lower temperature. At ordinary temperatures and pressures natural gas is lighter than air, while propane is heavier than air.

Propane is produced (as with other more complex hydrocarbons) through two processes. First, it can be extracted from natural gas streams in natural gas processing plants. Second, it can be produced by refiners as part of the crude oil cracking process. Today the former method of production accounts for more than seventy percent of domestic supply. North American supplies of propane are adequate to meet the entire U.S. demand. Unlike customers of gasoline, diesel fuel, and heating oil, propane customers are not dependent upon supplies from foreign nations. (Although some propane is imported, the volume is dramatically less than the volume of exports.) Propane is in essence a byproduct, and, from a commercial perspective, production varies not so much with the demand for propane as the demand for the products of which it is a byproduct (natural gas and refinery products).

The nation is in the midst of a boom in natural gas production, largely involving the production of natural gas from shale formations. Because natural gas liquids draw higher prices in the market than natural gas on a British thermal unit (Btu) basis, producers are aggressively seeking shale gas that is rich in hydrocarbon liquids. As a result, domestic supplies of propane will be plentiful for the indefinite future.

Propane has applications in residential and commercial markets for heating (furnaces, boilers, and gas logs), water heating, cooking, and clothes drying. It is well known across America, even among those who do not use it as a primary home fuel, as a fuel source for barbecues, outdoor stoves, heaters, and the like. About fourteen million American families use propane for these various applications. Approximately six million households heat with propane. Similarly, propane has wide usage as a cooking fuel in recreational vehicles and boats. Additionally, propane commands a significant market as a transportation fuel, for forklifts, buses, vans, trucks, and cars. Indeed, there are more propane vehicles on the road than either electric or natural gas vehicles. Propane is also used as a fuel in the industrial sector both for space heating and process applications. Propane is used on nearly one million farms for irrigation pumps, grain dryers, standby generators, and other farm equipment.

Propane is a low-carbon fuel. At the point of combustion it produces 62 kg of CO_2/MMBtu, compared to 53 kg for natural gas, 71 kg for gasoline, and 93 kg for bituminous coal. Factoring in upstream emissions, propane produces 74 kg of CO_2/MMBtu, compared to 65 kg for natural gas, 91 kg for gasoline, and 221 kg for electricity. (The large number for electricity reflects the significant thermal loss in generation and the thermal loss in transmission and distribution.) A key fact in regard to carbon emissions is that when propane is released (*i.e.*, fugitive) into the atmosphere, it has essentially no greenhouse gas (GHG) effect because it deteriorates rapidly. In contrast, natural gas released into the atmosphere is approximately 25 times more potent than CO_2 as a GHG.

Propane accounts for approximately two percent of the primary energy consumed in the United States, compared to 29 percent for natural gas, 28 percent for coal, and 41 percent for petroleum products. Yet propane accounts for only one percent of the nation's GHG emissions.

Propane is essentially "portable natural gas." Most propane today is produced alongside natural gas. It is used in the same applications as natural gas. Propane has an emissions profile similar to natural gas but with the added benefit of not being a GHG itself. Propane has the important benefit of being easily transportable to areas where there is no natural gas infrastructure.

Mr. WHITFIELD. Thank you very much. At this time, Mr. Logan, you are recognized for 5 minutes.

STATEMENT OF ANDREW LOGAN

Mr. LOGAN. Great. Thank you, Mr. Chairman, and members of the subcommittee for the opportunity to be here today to testify on the economic and environmental impacts of natural gas flaring in the United States. I am Andrew Logan. I direct the oil and gas program at Ceres, and we are a coalition of institutional investors and environmental organizations working to make capital markets more environmentally and socially sustainable. We have over 100 institutional investor members representing over $11 trillion in total assets united by the belief that strong environmental performance drives strong financial performance over time. Our investor members have significant financial exposure to the oil and gas sector, and want to see the industry succeed.

And while Shell Oil is bringing significant economic benefits to the United States, we believe that the way the resource is currently being developed is shortsighted, and fails to capture its full value, at least in certain parts of the country. Our investors believe that flaring natural gas is environmentally destructive, economically wasteful, and, most importantly, almost always unnecessary. And, despite well-intentioned and quite significant efforts by some companies, the problem is getting worse, and will continue to get worse until the regulatory environment changes, so that flaring is no longer the cheapest and easiest option.

Flaring is a problem that the U.S. thought it had left behind in the 1950s, but the rapid growth of tidal oil production in the United States has been accompanied by a dramatic increase in flaring that has propelled the U.S. into the top 10 gas flaring countries in the world. And most of this flaring, as you know, occurs at oil wells drilled in areas that lack the infrastructure necessary to capture the gas that comes out of the ground with the oil. And instead of investing in the necessary infrastructure to capture that gas, companies often choose to simply flare it off, where regulations allow them to do so.

It is important to note, though, that lack of infrastructure is only part of the problem. Roughly half of all the flaring in North Dakota comes from wells that are already connected to pipelines, so we need better planning as well. I think we really want to see this industry plan its wells with the idea that natural gas has value.

Flaring comes at a steep environmental cost. Flaring is a major contributor to greenhouse gas emissions. It is the equivalent of adding a million cars a year to the road in North Dakota alone. But the environmental impact of flaring is not its sole cost. North Dakota gas is so rich in valuable natural gas liquids, like propane, that this is about the last gas in the world that you would want to flare. In fact, over the course of 2012, North Dakota producers flared over a billion dollars of natural gas, a massive economic waste.

So flaring is clearly environmentally damaging, it is economically wasteful, but most importantly, it is avoidable. The North Dakota Industrial Commission has run the numbers, and has concluded that it is economic to capture this gas, in large part due to its high liquid content, but yet flaring in the State is still north of 30 percent. And that is because, while capturing gas produces positive economic returns, it doesn't match the returns from drilling the next oil well. So if regulations allow that sort of short term decision-making, as they do in North Dakota, many companies will simply make that choice.

Our investors take a long term view, and want to see the value of the resource maximized, and they are deeply concerned by the current approach to development. The Bakken Formation has been around for 360 million years. It is not going anywhere. If you take a little bit of extra time to develop the resource in a thoughtful and deliberate way, it seems to me that we should strongly encourage that.

So we are working with our investors to push the industry to take a longer term view, and it is important to acknowledge that some companies, like Continental and Hess, are doing so. And yet the data are clear, the problem is getting worse, and not better. Flaring in North Dakota hit 36 percent in December, which is a new record. This means that more than a third of all the natural gas produced in that State is going up in smoke at the same time as consumers around the country are seeing price spikes, and, in places, actual shortages of propane.

So, from my perspective, flaring is an indefensible economic waste, but it also represents a major opportunity, a billion-dollar-a-year opportunity, for entrepreneurs, as well as for the industry itself. We are seeing huge amounts of innovation going on, and there is a potential for a real American success story here, but this technology is having a hard time getting a foothold because it is hard to compete with free. And right now, in North Dakota, flaring is free. So if you take only one point away from my testimony today, it is that it shouldn't be. Thank you.

[The prepared statement of Mr. Logan follows:]

One-page summary of testimony of Andrew Logan
Director, Oil & Gas Industry Program
Ceres

Before the House Energy and Commerce Committee
Subcommittee on Energy and Power
March 6, 2014

1. Flaring of associated natural gas is a growing problem in the United States
    a. The flaring rate in North Dakota hit a record high of 36% in December, the most recent month for which data is available
    b. Texas has seen a 10-fold increase in flaring permits since 2010, and flaring is a growing concern in Wyoming as well.
    c. Despite significant investment, and leadership by a handful of companies, the problem is only getting worse and will continue to get worse until the regulatory environment changes so that flaring is no longer the cheapest and easiest option.
2. Flaring is environmentally destructive…
    a. In 2012, the emissions from the flared gas in North Dakota alone were equivalent to adding over one million cars to the road.
    b. In addition, because the flares used often only partially combust the natural gas, a variety of other hazardous pollutants are generated by the process, including black carbon, another potent driver of climate change with adverse health effects.
3. Economically wasteful…
    a. In 2012, North Dakota oil and gas producers flared more than $1 billion of natural gas, a massive economic waste.
4. And largely avoidable
    a. According to the North Dakota Industrial Commission, it is economic to capture Bakken gas, in large part due to its high liquids content. But flaring in the state is still at around a third of the total gas production. And that is because, while capturing gas produces positive economic returns, it doesn't match the returns from drilling the next oil well. So if regulations allow that sort of short-term decision making, as they do in North Dakota, many companies will make that choice.
5. Flaring will only be solved when the regulatory structure changes so that flaring is no longer the easiest option. This holds the potential to unleash massive innovation, and capture a $1 billion/year market opportunity
6. At the moment, flaring regulation is done mostly at the state level. There is an option for federal oversight by expanding EPA New Source Performance Standards, which currently only cover natural gas wells, to include oil wells.

Ceres

Mobilizing Business Leadership for a Sustainable World

Testimony of Andrew Logan
Director, Oil & Gas Industry Program
Ceres

Before the House Energy and Commerce Committee
Subcommittee on Energy and Power
March 6, 2014

Chairman Whitfield, Ranking Member Rush, members of the subcommittee, thank you for the opportunity to be here today to testify on the economic and environmental impacts of natural gas flaring in the United States.

Ceres is a non-partisan, non-profit organization. We are a coalition of institutional investors and environmental organizations working to make capital markets more environmentally and socially sustainable. We have over 100 institutional investor members representing over $11 trillion in assets, united by the belief that strong environmental and social performance drives strong financial performance over time.

Our investor members have significant financial exposure to the oil and gas sector, and very much want to see the industry succeed. While shale oil is bringing significant economic benefits to the United States, we believe that the way the resource is currently being developed is extremely short-sighted, and is failing to capture its full value.

Our investors believe that flaring natural gas is environmentally destructive, economically wasteful and, most importantly, it is almost always unnecessary. And despite well-intentioned and quite significant efforts by some companies, the problem is getting worse, and will continue to get worse until the regulatory environment changes so that flaring is no longer the cheapest and easiest option.

Flaring is a problem that the US thought it had left behind in the 1950s. But the rapid growth of tight oil production in the United States, in places like North Dakota and Texas, has been accompanied by a dramatic increase in flaring that has propelled the U.S. into the top 10 gas flaring countries globally along with Russia, Nigeria, and Iraq.[1] This is not the sort of company that the US should be keeping.

Most of this flaring is occurring at oil wells drilled in areas that lack the pipeline and processing infrastructure necessary to capture the gas that comes out of the ground with the oil. Instead of investing in the infrastructure necessary to capture that gas, companies are often choosing to simply flare it off where current regulations allows them to do so. It is important to note, though, that lack of infrastructure is only part of the problem. Roughly half of all flaring in the Bakken comes from wells that are already connected to pipelines.[2] So we need better planning as well—we want to see industry plan its wells with the idea that natural gas has value.

This is coming at a steep environmental cost. Flaring is a major contributor to greenhouse gas emissions. In 2012, the emissions from the flared gas in North Dakota alone were

[1] Global Gas Flaring Reduction "Estimated Flared Volumes from Satellite Data, 2007-2011" http://go.worldbank.org/D03ET1BVD0

[2] Fielden, Sandy "Set Fire To The Gas– The Fight to Limit Bakken Flaring" 6 May 2013, https://rbnenergy.com/set-fire-to-the-gas-the-fight-to-limit-bakken-flaring

equivalent to adding over one million cars to the road.[3] In addition, because the flares used often only partially combust the natural gas, a variety of other hazardous pollutants are generated by the process, including black carbon, another potent driver of climate change with adverse health effects.

While flaring in North Dakota has received the most attention, it is a problem nearly everywhere that has seen significant tight oil production. Texas has seen a 10-fold increase in flaring permits since 2010, and flaring is a growing concern in Wyoming as well.

The environmental impact of flaring is not its sole cost. North Dakota gas is so rich in valuable natural gas liquids like propane and butane that this is about the last gas you would want to flare. In fact, over the course of 2012, North Dakota oil and gas producers flared more than $1 billion of natural gas, a massive economic waste. [4]

So flaring is clearly environmentally damaging. It is economically wasteful, to the tune of a billion dollars a year- and growing- in North Dakota alone. But most importantly, it is avoidable.

[3] Salmon, Ryan "Flaring up: North Dakota Natural Gas Flaring More Than Doubles in Two Years" http://www.ceres.org/resources/reports/flaring-up-north-dakota-natural-gas-flaring-more-than-doubles-in-two-years/view
[4] ibid

The North Dakota Industrial Commission has run the numbers, and has concluded that it *is* economic to capture this gas, in large part due to its high liquids content.[5] But flaring in the state is still at around a third of the total gas production. And that is because, while capturing gas produces positive economic returns, it doesn't match the returns from drilling the next oil well. So if regulations allow that sort of short-term decision making, as they do in North Dakota, many companies will make that choice.

Our investors take a long-term view and want to see the value of the resource maximized. They are deeply concerned by the current approach to development. The Bakken formation has been around for 360 million years. It's not going anywhere. If it takes a little extra time to develop the resource in a thoughtful and deliberate way, it seems to me we should strongly encourage that.

We are working with our investors to push the industry to take a longer-term view, and it is important to acknowledge that some companies are doing so. Continental, the biggest producer in the Bakken, is sharing drilling plans with pipeline companies several years in advance to allow infrastructure to get a head start, and has managed to bring its flaring rate down to 10%. Hess is planning its drilling program to ensure wells can be quickly connected to gas gathering lines and has made investments in gas processing infrastructure. Yet the data are clear: the problem is getting worse, not better. Flaring in North Dakota hit 36% in December, a new record. This means that more than 1/3 of all natural gas produced in the state is going up in smoke, at the same time as consumers

[5] Helms, Lynn "Director's Cut" https://www.dmr.nd.gov/

around the country are seeing price spikes from natural gas in this cold winter, along with actual shortages of propane in many places.

Flaring is an indefensible economic waste, but it also represents a major opportunity- a $1 billion/year opportunity for entrepreneurs as well as the industry itself. We are seeing huge amounts of innovation going on, with companies from start-ups to General Electric developing technologies to utilize gas at the wellhead or get it to market without pipelines. There is the potential for a real American success story here. But this technology is having a hard time gaining a foothold because it's hard to compete with free. And right now in North Dakota, flaring is free. If you take only one point away from my testimony today, it's that it shouldn't be.

Mr. WHITFIELD. Thank you, Mr. Logan. Mr. Whittington, you are recognized for 5 minutes.

STATEMENT OF CHARLES "SHORTY" WHITTINGTON

Mr. WHITTINGTON. Thank you very much. Mr. Chairman, and members of this committee, thank you for inviting me here to testify on the issue of propane transportation. My names is Charles "Shorty" Whittington. I am president of Grammer Industries, a for-hire trucking company headquartered in Grammer, Indiana. I am also the former chairman of the American Trucking Association, and I currently serve on the Board of the National Tank Truck Carriers. My company operates 120 specialty MC–331 transport tank trailers, 115 of those which are capable of transporting propane. Not only do I haul propane, I also am a large consumer of propane, as a farmer, and we have about 1,500 acres. My fleet currently employs over 200 people, and the logistics personnel, and professional drivers.

This past year, Grammer Industries has experienced a substantial increase in propane hauls. In an average year, Grammer dedicated between 25 and 30 tank trucks to haul propone in the winter months. This year, we have dedicated over 80 units to do this service. I would like to further detail Grammer's experience this winter in hauling propane.

There are roughly 11,000 tank truck trailers in the United States capable of hauling propane. To add some perspective to this, each of these specialized trailers cost about $150,000, and a new tractor costs $125,000. This is a sizable investment for carriers to participate in this segment of business.

With the increase of natural gas production across the nation, and the corresponding increasing demands for tank truck services, competition for the use of the existing tank truck trailers is at an all-time high, straining existing capacity and new trailer production capacities at the same time. The reality of this is, if I ordered a new tank truck to haul propane today, I would receive it in May of 2015. These tank trailers have a capacity of 10,600 gallons. However, because of product expansion and government regulations, we can only fill these tanks to 85 percent of capacity, or, in other words, about 9,000 gallons.

Typically Grammer's average length of haul falls into the 50 to 100 mile range. That has been the way it has been for the last 10 years. However, given the exceedingly difficult market dynamics in play, we found ourselves making longer hauls that have exceeded 800 miles this year. When propane shortages occur, like this winter, companies like mine need to be able to respond accordingly. In times of crisis, the tank truck community has offered its capacity and services to emergency respond teams many times, as our carriers haul essential products necessary for the recovery, whether it is from hurricane relief in the Gulf Coast, or a propane shortage in the midst of a devastating Midwest winter.

As we have seen in every crisis situation, the Federal hours of service regulations is a key obstacle that may be waived in order to help our deliveries to the affected areas. While waiving these hours of service regulations has been extremely helpful, the current process of seeking this relief can be very confusing, time consuming, and the deterrent of both our customers and the critical service we provide.

If the President, the Governor of a State, or an FFCSA regional field administrator declares a regional emergency, certain regulatory constraints are suspended for drivers and motor carriers providing direct relief to the emergency. This is true regardless of where the driver's trip originates, even if the emergency was only declared in one State, provided they are offering relief to the affected area.

However, enforcement officials in distant States, or even neighboring ones, may not be aware that drivers may legally take advantage of this regulatory exemption which results in the various roadside enforcement disparities. And, with today's CSA rules, these disparities can put a carrier like myself out of business. Exceptions provided under the circumstances are usually in effect for 30 days. Though authorized officials may extend the relief for another 30 days, they do not always make such decisions in a timely manner.

To address these issues, Congress should work with the Department of Transportation to evaluate ways in which the emergency exemption declaration process could be improved at regional, State, and local levels. Additionally, the Department of Transportation and State should seek to improve communication with enforcement officials when regulatory relief has been granted, identifying which drivers are entitled to that relief, and what rules are for that emergency.

Again, I would like to thank you for the opportunity to testify at today's hearing, and I will be very happy to respond to any questions that you may have. Thank you very much.

[The prepared statement of Mr. Whittington follows:]

Statement of

Charles "Shorty" Whittington
President of Grammer Industries, Grammer Indiana

On behalf of:

AMERICAN TRUCKING ASSOCIATIONS, INC. (ATA)

&

NATIONAL TANK TRUCK CARRIERS (NTTC)

BEFORE THE HOUSE SUBCOMMITTEE ON ENERGY AND POWER
OF THE COMMITTEE ON ENERGY AND COMMERCE

HEARING ON THE "BENEFITS OF AN CHALLENGES TO ENERGY ACCESS IN THE 21ST CENTURY"

MARCH 6, 2014

ATA
AMERICAN TRUCKING ASSOCIATIONS
Driving Trucking's Success

Mr. Chairman and members of the Committee, thank you for inviting me to testify before you today on the issue of propane transportation.

My name is Charles "Shorty" Whittington. I am President of Grammer Industries, a for-hire trucking company headquartered in Grammer, Indiana. I am also a former Chairman of the American Trucking Associations, and I currently serve on the Board of the National Tank Truck Carriers.

My company operates 120 specialty MC331 tank trailers, 115 of which are capable of transporting propane. Not only do I haul propane, I am also a large consumer of propane as a farmer, with about 1,500 acres under management. My fleet currently employs over 200 logistics personnel and professional drivers.

This past year, Grammer Industries has experienced a substantial increase in propane hauls. In an average year, Grammer dedicates between 25 to 30 tank trailers to haul propane over the winter months. This year we have dedicated 80 trailers to this service. The significance of this sharp increase is that 95% of our hauls are not to the end user but the supplier for the end user.

I would like to further detail Grammer's experience this winter hauling propane. There are roughly 11,000 tank trailers in the U.S. capable of hauling propane. To add some perspective, each of these specialized trailers cost about $150,000 new, this is a sizable investment for carriers to participate in this segment. With the increase of natural gas production across the nation, and the corresponding increasing demands for tank truck services, competition for the use of existing tank trailers is at an all-time high, straining existing capacity and new trailer production capabilities at the same time. To put this in perspective, if I ordered a new tank truck today, I would not receive it before May of 2015.

Typical tank trailers have a capacity of 10,600 gallons. However, because of expansion we can only fill these tanks to 85% of capacity – or in other words – about 9,000 gallons. Typically, Grammer's average length of haul falls into the 50-100 mile range. However, given the exceedingly difficult market dynamics in play, we found ourselves making longer hauls that have exceeded 800 miles.

When propane shortages, like the ones we have experienced this winter, occur, companies like mine need to be able to respond accordingly. In times of crisis, the tank truck community has offered its capacity and services to emergency response teams many times, as our carriers haul essential products necessary for recovery whether for hurricane relief in the Gulf Coast or a propane shortage in the midst of a devastating Midwest winter. As we've seen in every crisis situation, the Federal Hours-of-Service regulation is a key obstacle that must be waived in order to help us make our deliveries to the affected areas. While waiving these HOS regulations has been extremely helpful, the current process for seeking this relief can be confusing, time consuming, and to the detriment of both our customers and the critical service we provide.

If the President, the Governor of a state, or an FMCSA Regional Field Administrator declares a regional emergency, certain regulatory constraints are suspended for drivers and motor carriers providing direct relief to the emergency. This is true regardless of where the driver's trip originates, even if the emergency was only declared in one state, provided they are offering relief to the affected area. However, enforcement officials in distant states, or even neighboring ones, may not be aware that drivers may legally take advantage of this regulatory exemption, which results in various roadside enforcement disparities.

Exemptions provided under such circumstances are in effect for 30 days. Though authorized officials may extend the relief for another 30 days, they do not always make such decisions in a timely fashion. Near the end of a given exemption period, companies like mine may not know the circumstances under which they are allowed to operate in the coming days. This uncertainty affects our ability to effectively plan and provide the most beneficial service.

In addition to the provisions for *regional* emergencies, there is also a provision that provides similar regulatory relief for *local* emergencies. This is triggered upon a declaration by a Federal, State, or local official having appropriate authority. Drivers and motor carriers operating under these declarations experience similar, if not worse, problems with confused roadside enforcement officials. Furthermore, relief under local emergency declarations is limited to five days, which also exacerbates the planning issues discussed earlier.

To address these issues, Congress should work with the Department of Transportation to evaluate ways in which the emergency exemption declaration process could be improved at regional, state and local levels. Additionally, the Department of Transportation and States should seek to improve communication with enforcement officials when regulatory relief has been granted, identifying which drivers may take advantage of it, and under what circumstances they may operate.

Again, thank you for the opportunity to testify at today's hearing, and I am happy to respond to any questions you may have.

Mr. WHITFIELD. Thank you, Mr. Whittington. Mr. Obeiter, you are recognized for 5 minutes.

STATEMENT OF MICHAEL OBEITER

Mr. OBEITER. Good morning, and thank you for the opportunity to contribute to the deliberations of this subcommittee. My name is Michael Obeiter, and I am a senior associate in the Climate and Energy Program at the World Resources Institute. WRI is a non-profit, non-partisan think tank that focuses on the intersection of the environment and socioeconomic development. I am pleased to be here today to offer WRI's perspective on the United States natural gas infrastructure, with a focus on the need for reductions in fugitive methane emissions, and forward-looking planning that takes into account the realities of a changing climate.

The U.S. currently finds itself in the midst of an energy boom, driven by technological advances in the extraction of oil and natural gas. Our domestic energy resources are the envy of much of the world, yet we must also weigh the consequences of our actions on the natural environment. The decisions we are making will have long lasting impacts on air quality and the climate.

Methane, the primary component of natural gas, is a powerful greenhouse gas, at least 34 times as powerful as carbon dioxide at trapping heat. Although natural gas emits only 50 to 60 percent as much CO2 as coal when burned for electricity generation, fugitive methane emissions throughout the natural gas life cycle undermine the climate advantage of switching from coal to gas. While we don't yet know exactly how much methane is escaping into the atmosphere from wells and pipelines, we know enough to recognize that fugitive methane emissions are a significant environmental problem, and one that we know how to address.

There are many commercially available technologies that reduce or eliminate methane emissions, and pay for themselves in 3 years or less. Analysis by WRI and others has demonstrated that a one percent leakage rate system-wide is an achievable and cost-effective benchmark. Below one percent, we can say with certainty that fuel switching from coal to gas, or from diesel to gas in heavy duty trucks and buses, is a net positive for the climate.

Beyond this environmental impact, methane has economic value, and any cubic foot that is leaked, vented, or flared is one less cubic foot that can be put to productive use. The fact that emissions control technologies are not utilized to the extent they should be is evidence of a market failure that requires policy intervention. Thankfully, there are a number of options available to Congress to address this issue, including tax incentives for investment in emissions control technologies, requiring companies to perform monthly emissions monitoring and repair as a condition for receiving the right to drill on Federal lands, and supporting applied research and development to the Department of Energy to drive down the costs of emissions control technologies, and allow companies to bring more gas to market, in much the same way that DOE played a key role in the development of hydraulic fracturing technology.

I have included additional policy options in my written testimony. As this subcommittee explores the challenges and opportunities of energy infrastructure in the 21st century, I encourage its members to propose innovative ways to simultaneously cut waste, increase government royalties, and combat climate change by reducing fugitive methane emissions.

Yet these unchecked emissions are merely one symptom of a national energy landscape that systematically undervalues long term prosperity. Climate change, and the rising sea levels, reduced agricultural yields, and more extreme weather it brings, threatens to alter our way of life and dampen prospects for economic growth, including in the energy sector.

A recent GAO report found that, "climate changes are projected to affect infrastructure throughout all major stages of the energy supply chain, thereby increasing the risk of disruptions." This underscores the need for the private sector to take climate into account when it makes investment decisions. While many companies are already incorporating a de facto price on carbon into their decision-making process, lack of clarity complicates their attempt to seize the economic opportunity of the transition to a low carbon economy.

Luckily, smart climate policy is indisputably compatible with smart economic policy. Reducing methane emissions from leaky infrastructure, for example, is good for business. Numerous studies have made the case that inaction on climate change will be more expensive than taking action now to mitigate greenhouse gas emissions. Even the Defense Department is concerned, calling climate change, "a threat multiplier that can enable terrorist activity and other forms of violence."

Taken together, these arguments point to the need to take climate risks into account when making investment decisions on long lasting infrastructure. The infrastructure choices we make today will reverberate for decades. Ignoring the climate when making these decisions risks stranding valuable assets, or locking in dangerous levels of greenhouse gas emissions, and potentially catastrophic climate change. We owe it to ourselves, and future generations, to make sure we get those choices right.

Thank you again, Mr. Chairman, Ranking Member McNerney, for the opportunity to be here today. I look forward to your questions.

[The prepared statement of Mr. Obeiter follows:]

TESTIMONY OF MICHAEL OBEITER

SENIOR ASSOCIATE, CLIMATE AND ENERGY PROGRAM
WORLD RESOURCES INSTITUTE

HEARING BEFORE THE U.S. HOUSE OF REPRESENTATIVES ENERGY AND COMMERCE SUBCOMMITTEE ON ENERGY AND POWER: "BENEFITS OF AND CHALLENGES TO ENERGY ACCESS IN THE 21ST CENTURY: FUEL SUPPLY AND INFRASTRUCTURE"

March 6, 2014

Good morning, and thank you for the opportunity to contribute to the deliberations of this Subcommittee. My name is Michael Obeiter, and I am a senior associate in the Climate and Energy Program at the World Resources Institute (WRI). WRI is a non-profit, non-partisan think tank that focuses on the intersection of the environment and socio-economic development. We go beyond research to put ideas into action, working globally with governments, business, and civil society to build transformative solutions that protect the earth and improve people's lives. We operate globally because today's problems know no boundaries. We provide innovative paths to a sustainable planet through work that is accurate, fair, and independent.

Summary

I am pleased to be here today to offer WRI's perspective on the United States' natural gas infrastructure, with a focus on the need for reductions in fugitive methane emissions and forward-looking planning that takes into account the realities of a changing climate.[1] The U.S. currently finds itself in the midst of an energy boom, driven by technological advances in the extraction of oil and natural gas. Our domestic energy resources, and the self-sufficiency they can bring, are the envy of much of the world. Yet we must also weigh the consequences of our

[1] While this testimony focuses primarily on methane emissions, WRI is committed to reducing all greenhouse gas emissions to avoid the most dangerous impacts of climate change, and to minimizing the full scope of impacts caused by energy production and use.

actions on the natural environment; the decisions we are making will have long-lasting impacts on air quality, water scarcity, and the climate. We can balance economic growth and reductions in greenhouse gas (GHG) emissions, but to do so we must correct the various market failures that have allowed for unchecked emissions of carbon pollution and other GHGs.

Methane, the primary component of natural gas, is a potent greenhouse gas. Though it is short-lived in the atmosphere, methane is 34 times as powerful as carbon dioxide (CO_2) at trapping heat when averaged over a 100-year timeframe.[2] Although natural gas emits only 50-60% as much CO_2 as coal when burned for electricity generation, fugitive methane emissions throughout the natural gas life cycle undermine the climate advantage of switching from coal to gas. While we don't yet know with precision exactly how much methane is escaping into the atmosphere from wells and pipelines, we know enough to recognize that fugitive methane emissions are a significant environmental problem – one that we know how to fix.

Beyond its environmental impact, methane has economic value, and any cubic foot that is leaked, vented or flared is one less cubic foot that can be put to productive use. Even with today's relatively low natural gas prices, many commercially available technologies can reduce or eliminate methane emissions and pay for themselves in three years or less (see Table 1, below).[3] The fact that these technologies are not often widely utilized is evidence of a market failure that requires policy intervention. To ensure that American energy resources are not

[2] Over a 20-year timeframe, methane is 86 times as powerful as CO_2 at trapping heat. See http://www.climatechange2013.org/images/report/WG1AR5_Chapter08_FINAL.pdf.
[3] For a detailed, though not necessarily comprehensive, list of technologies and case studies, see http://www.epa.gov/gasstar/tools/recommended.html.

wasted, and to reduce the impact of oil and natural gas production on the climate, Congress can undertake a number of measures, including:

- Provide tax credits or accelerated depreciation for purchases of, or R&D investments in, equipment to mitigate fugitive methane emissions, much like the Section 29 tax credit incentivized the use of new technologies for producing unconventional gas. As the U.S. Department of Energy (DOE) said in evaluating the success of the Section 29 credit, "[e]conomic and tax incentives can greatly accelerate industry's adoption of technology by helping justify capital, by lowering economic risk and by challenging the financial community's imagination."[4] Tax credits could also be provided to companies on the basis of volume of avoided methane emissions.
- Require the use of methane emissions control technologies at all oil and gas operations on public lands, as some Bureau of Land Management Field Offices have begun to do.[5]
- Require gas companies and their service contractors to perform monthly emissions monitoring and repair as a condition for receiving the rights to extract oil and gas from federal lands.
- Authorize and fund the expansion of basic science and applied technology research programs at the U.S. Department of Energy, including R&D performed by the Office of Fossil Energy and the National Labs. Additional research is needed to bring down the cost of emissions monitoring technologies, to accelerate innovations in emissions control technologies that continue to reduce the cost of this equipment, and to bring lab-scale technologies up to pilot scale. Funding to expand these programs can be raised by increasing royalties from drilling on public lands, and by having industry participate in

[4] Source: http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/1a3.pdf.

[5] See, for example, http://www.westernlaw.org/blog/2013/12/colorado-blm-field-office-takes-critical-action-clean-oil-and-gas-industry-methane-poll.

research while sharing the costs. DOE research and development is a public good that was instrumental in bringing many advanced energy technologies and techniques, including hydraulic fracturing, to market, and can help reduce the hurdles to widespread use of leak-detection, emissions-measurement, and low-emissions technologies. [6,7]

- Exercise Congressional oversight of executive branch agencies – including the Environmental Protection Agency (EPA), the Department of the Interior (DOI), the Federal Energy Regulatory Commission (FERC), and the Department of Transportation (DOT) – to ensure they are using all tools at their disposal to require cost-effective reductions of methane from all components of energy infrastructure on both public and private lands.
    - Congress should direct EPA to regulate methane directly, rather than mandating reductions of volatile organic compounds (VOCs) and achieving methane reductions as a co-benefit. After processing, natural gas is almost entirely methane, so targeting it would achieve deeper reductions than targeting VOCs. EPA, with Congressional oversight, should also ensure that the technologies developed by and in conjunction with DOE research programs are being appropriately utilized.

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[6] For more information on the role of publicly-funded research in accelerating the shale gas revolution, see http://thebreakthrough.org/archive/new_investigation_finds_decade and http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/1a3.pdf.

[7] As other nations, especially those with binding GHG reduction targets, begin to consider their own unconventional gas resources, there will likely be export markets for many of these technologies, yet another economic benefit of increased research and development funding.

- Congress should ensure DOI aggressively pursues all options at its disposal to minimize wasting of energy resources on public lands, the source of nearly 18% of all U.S. natural gas production in FY 2012.[8]
- Congress should work with FERC, DOT, and stakeholders to improve sharing of costs and benefits realized in utilizing emissions control technologies in pipeline and service contracts, to incentivize use of emissions control technologies by all service providers.

- Provide federal assistance to state agencies that are acting to rein in fugitive methane emissions.
- Fully fund offices and programs at EPA, including Natural Gas STAR, that encourage the voluntary use of emissions reduction technologies and recognize industry leaders that commit to implementing best practices throughout their operations.[9]

Beyond these relatively narrow, but important, measures to reduce fugitive methane emissions from U.S. energy infrastructure, there is much that Congress can do to correct the broader market failure that has allowed the buildup of greenhouse gases in our atmosphere and which threatens to be an increasingly disruptive force in the coming years. Rising sea levels, changing weather patterns, reduced agricultural yields, and more extreme storms will change our way of life and dampen prospects for economic growth. The private sector needs to take climate into account

[8] Source: http://energycommerce.house.gov/sites/republicans.energycommerce.house.gov/files/20130228CRSreport.pdf.
[9] For additional policies to address fugitive methane emissions, see http://www.wri.org/publication/clearing-air.

when it makes investment decisions and infrastructure choices; indeed, many companies already are.[10]

Regulatory and policy certainty would be a welcome development for many companies that acknowledge the inevitability of a comprehensive national climate policy. President Obama, to his credit, has started the U.S. down the path of smart emissions reductions with his multi-sector Climate Action Plan. Congress should support these efforts, while simultaneously working on ways to drive even deeper reductions by setting an implicit or explicit price on carbon pollution and other GHG emissions.[11]

We are living in a new era of domestic energy abundance. But we must tread carefully if we are to safeguard the climate while fostering economic growth. There is much that we can do now to reduce methane emissions, eliminate waste, and save money, and government can play a role in assuring that these opportunities are recognized. Yet we cannot lose sight of the need to put the country on a path toward a low-carbon future, and should not allow near-term profits to jeopardize long-term prosperity. The infrastructure choices we make today will reverberate for the next 40-50 years; ignoring the climate when making these decisions risks stranding valuable assets, or locking in dangerous levels of GHG emissions and potentially catastrophic climate change. We owe it to ourselves and future generations to make sure we get those choices right.

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[10] In December, the Carbon Disclosure Project released a report finding that many major U.S. companies, including Wal-Mart and ExxonMobil, are factoring a "shadow price" of carbon into their strategic plans. For more information, see http://www.reuters.com/article/2013/12/05/usa-energy-carbon-idUSL2N0JK0V220131205.

[11] In February 2013, WRI published a report entitled "Can the U.S. Get There from Here?," which examined the emissions reductions that could be achieved through existing executive authorities. The report's authors found that ambitious action across the suite of greenhouse gases could enable the U.S. to meet its international commitment of reducing GHG emissions by 17% below 2005 levels by 2020. However, by the middle of next decade, additional legislation will be needed to ensure we remain on the trajectory to achieve the scale of reductions by mid-century that scientists tell us will be necessary if we are to avoid the most catastrophic impacts of climate change. For more information, see http://www.wri.org/publication/can-us-get-there-here.

The shale gas boom has changed the picture of the U.S. energy supply

Over the last decade, the U.S. has rather suddenly found itself in an era of resource abundance, as evinced by the fact that the Energy Information Administration (EIA) estimates that we are now the world's largest producer of both oil and natural gas, surpassing Saudi Arabia and Russia.[12] Yet with this great power comes great responsibility – the responsibility to demonstrate to the rest of the world that it can extract these fuels in ways that minimize local environmental impacts and needless venting and flaring of natural gas, while pivoting to investment in and deployment of 21st century renewable energy technologies.

In the near term, the EIA projects that natural gas will remain an important part of our domestic energy mix, with production increasing by 44% between 2011 and 2040 – an increase driven almost entirely by shale gas accessed through horizontal drilling and hydraulic fracturing.[13]

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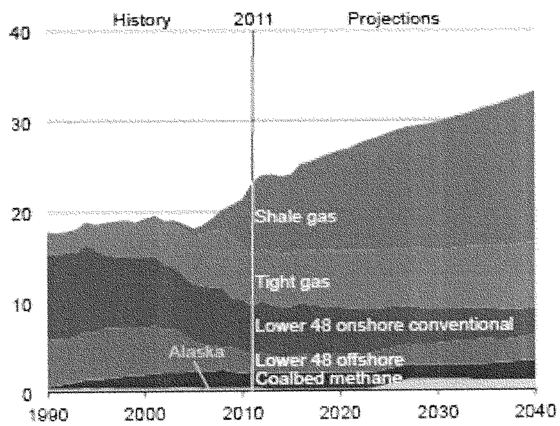
[12] See http://www.eia.gov/todayinenergy/detail.cfm?id=13251.

[13] Source: http://www.eia.gov/forecasts/aeo/MT_naturalgas.cfm.

Figure 1: Historical and Projected U.S. Natural Gas Production, by Source



Source: EIA, Annual Energy Outlook 2013

What this tells us is that we have to "get it right" when it comes to minimizing the impact of natural gas development. Natural gas may emit 50-60% the CO_2 of coal at the point of combustion, but any climate advantage natural gas has is reduced by leaks and vents at the wellhead, at processing plants and compressor stations, and along transmission and distribution pipelines.

Yet we must remember that, even if fugitive methane emissions are eliminated altogether, natural gas is, at best, a stepping stone to help the U.S. transition to a low-carbon economy (see "The natural gas stepping stone," below); while we traverse that stepping stone, cutting CO_2 and other GHG emissions from across the economy as we go, we need to take advantage of cost-effective opportunities to reduce methane emissions and soften the impact of peak warming.

We can – and should – reduce methane leakage to 1% or less

Leaking infrastructure should be a key concern to those who would tout the virtues of "clean-burning" natural gas; in addition to contributing to global warming, leaks of VOCs from natural gas systems contribute to local air pollution issues like smog.[14] While the goal for industry and government should be zero leakage across all infrastructure, an important benchmark to keep in mind is a leakage rate of 1% of total production. Keeping fugitive methane emissions below 1% would ensure that natural gas is not only more climate-friendly than coal, but also a net positive when switching from diesel to natural gas in heavy-duty vehicles.[15]

Current estimates of total upstream fugitive methane emissions vary widely, primarily due to the lack of measurement data (to date, most estimates, including those from EPA and industry, are calculated from the bottom up using activity data and engineering calculations).[16] However, a number of studies have been released in the last year, and more are currently underway, that will help shed some light on this issue.

A recent study, led by researchers from Stanford University, synthesized the results of over 200 previous studies (including many that used direct or atmospheric measurements), and concluded that methane emissions in general, and those from natural gas systems in particular, are much greater (as much as 75% greater from all sources) than official estimates from EPA's most recent

[14] Due to leaks and vents from natural gas operations, Wyoming and other rural states in the West have smog that rivals that seen in Los Angeles. For more details, see http://www.nbcnews.com/id/41971686/ns/us_news-environment/.

[15] To ensure that natural gas' impact on the climate is less than that of coal or diesel fuel over any time horizon, the upstream leakage rate must be capped at roughly 1%. For more information, see http://www.pnas.org/content/109/17/6435.

[16] The fugitive methane leakage rate currently estimated by EPA is roughly 1.4%, a figure which has fallen sharply in recent years in response to estimates reported in an industry-led survey.

Greenhouse Gas Inventory.[17] While EPA has not yet incorporated the results of this study into their annual Inventory, we hope that the agency will acknowledge that its current estimates likely understate the scale of methane emissions from natural gas systems.

A study released late in 2013, led by researchers at Harvard University, reached similar conclusions through different methods. Using atmospheric measurements from aircraft and stationary towers, the researchers found that total methane emissions from all sources were likely 50% greater than previous estimates from the EPA Inventory. However, there were even greater divergences within individual sectors; methane emissions from oil and gas development were approximately five times greater than EPA estimates. Average leakage rates of that magnitude, if applicable across all natural gas systems in the country, would call into question any climate advantage natural gas claims to possess over coal.[18]

Perhaps the most anticipated series of studies are those coordinated by the Environmental Defense Fund, led by university researchers and with participation from a number of large oil and gas companies. Over a dozen studies are underway, measuring leaks throughout the natural gas life cycle, from wellhead to end-use. One such study, led by researchers at the University of Texas at Austin and looking at methane emissions from natural gas production operations, has already been published, and its conclusions are illustrative.[19] With the cooperation of nine oil and gas majors, the study found that EPA's 2012 standards[20] to limit the emissions of volatile organic

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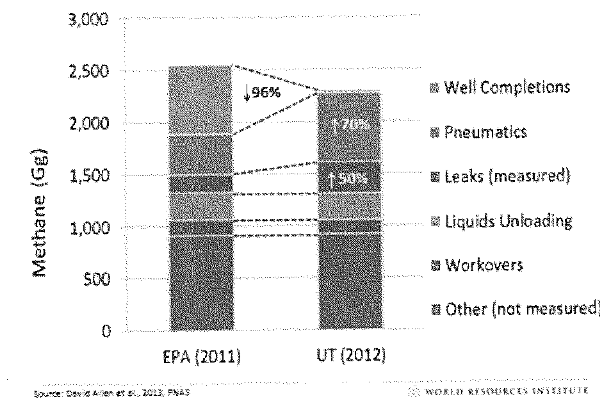
[17] For the full study, see http://www.sciencemag.org/content/343/6172/733.full.
[18] For more information, see http://www.wri.org/blog/new-study-raises-big-questions-us-fugitive-methane-emissions. For the full study, see http://www.pnas.org/content/early/2013/11/20/1314392110.full.pdf+html.
[19] For the full study, see http://www.pnas.org/content/110/44/17768.full.
[20] For more information on EPA's standards, see http://www.epa.gov/airquality/oilandgas/actions.html and http://www.wri.org/blog/how-epa%E2%80%99s-new-oil-and-gas-standards-will-reduce-greenhouse-gas-emissions.

compounds and hazardous air pollutants during well completion were working as intended (and reducing methane as a co-benefit), and that the EPA Inventory was underestimating the emissions from several sources during the production stage.[21]

Figure 2: Summary of Results from UT-Austin Production Stage Study



At the far end of the natural gas life cycle, in the distribution network, recent studies led by researchers at Duke University and Boston University have found thousands of leaks in the pipelines underneath Boston and Washington, D.C.[22] Although gas utilities maintain programs to identify and repair leaks that pose a threat to human health and safety, these studies found many such leaks that had thus far escaped detection. In addition to the safety concerns, these studies

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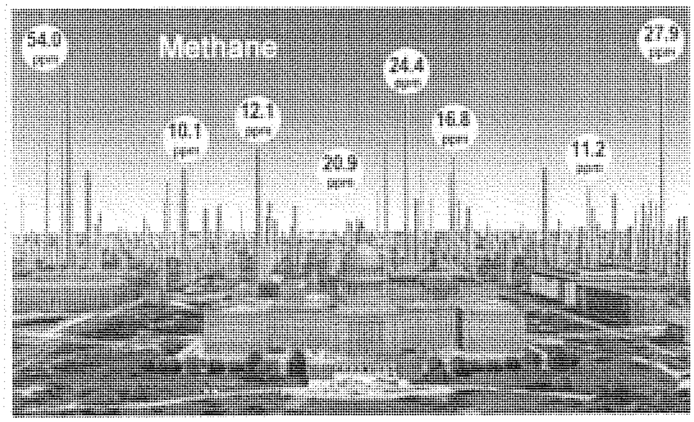
[21] For more information, see http://www.wri.org/blog/new-study-sheds-light-methane-leakage-natural-gas.
[22] For the Boston study, see http://www.sciencedirect.com/science/article/pii/S0269749112004800. For the Washington, D.C. study, see http://pubs.acs.org/doi/abs/10.1021/es404474x.

have demonstrated that distribution pipelines – some made of leaky cast iron that is over 60 years old – may be a much larger source of methane emissions than previously thought.

Figure 3: Detected Methane Leaks in the Distribution Network of Washington, D.C.



Source: Robert B. Jackson et al., 2014, Environmental Science and Technology.
Note: Normal background levels of methane are roughly 2 parts per million (ppm).

Taken together, what these and other studies illustrate is that despite the lack of precision in estimating a system-wide leakage rate, we know the problem is greater than previously thought, and we know enough to act. States have once again taken the lead on addressing fugitive methane emissions – regulations in Wyoming and Colorado served as the basis for the EPA New Source Performance Standard (NSPS) for well completions mentioned above – as Colorado is now at the forefront of addressing methane emissions directly. With the support of some of the largest operators in the state – including Anadarko Petroleum, Noble Energy, and Encana – the state established rules requiring implementation of leak detection and repair regimens at facilities across the state.[23] By requiring large oil and gas producers to inspect their equipment for leaks every month, and to fix the leaks they find, Colorado is demonstrating that sensible regulations to address fugitive methane emissions benefit all parties. In praising the rules, Encana noted that "[s]aving methane from leaking should also result in a financial benefit to the industry, since it should end up with more product to sell."[24] Congress should encourage states and the federal government to regulate methane emissions from oil and gas production, and should require the use of all practical emissions control technologies.

A number of such commercially available technologies can provide financial benefit to the oil and gas industry (see Table 1, below), and have been demonstrated to do so.[25] They address leaks and vents throughout the natural gas production life cycle, and while many are utilized voluntarily (and green completions will be required under the NSPS by January 2015), the level of methane emissions detected from natural gas infrastructure tells us that many are not. In a 2012 paper, the Natural Resources Defense Council estimated that over $2 billion worth of natural gas (at $4 per thousand cubic feet, or Mcf) is lost to the atmosphere each year; if leakage rates are indeed higher than previously estimated, or if the price of gas increases, those lost profits could be greater as well.

[23] See http://www.colorado.gov/cs/Satellite/CDPHE-AQCC/CBON/1251647985820.
[24] Source: http://www.scientificamerican.com/article/colorado-first-state-to-limit-methane-pollution-from-oil-and-gas-wells/.
[25] For a detailed list of technologies and case studies, see http://www.epa.gov/gasstar/tools/recommended.html.

Table 1: Methane Emissions Control Technologies, with Payback Period

Methane Capture Technology Costs and Benefits				
Technology	**Investment Cost**	**Methane Capture**	**Profit**	**Payout**
Green Completions	$8,700 to $33,000 per well	7,000 to 23,000 Mcf/well	$28,000 to $90,000 per well	< 0.5 – 1 year
Plunger Lift Systems	$2,600 to $13,000 per well	600 to 18,250 Mcf/year	$2,000 to $103,000 per year	< 1 year
TEG Dehydrator Emission Controls	Up to $13,000 for 4 controls	3,600 to 35,000 Mcf/year	$14,000 to $138,000 per year	< 0.5 years
Desiccant Dehydrators	$16,000 per device	1,000 Mcf/year	$6,000 per year	< 3 years
Dry Seal Systems	$90,000 to $324,000 per device	18,000 to 100,000 Mcf/year	$280,000 to $520,000 per year	0.5 – 1.5 years
Improved Compressor Maintenance	$1,200 to $1,600 per rod packing	850 Mcf/year per rod packing	$3,500 per year	0.5 years
Pneumatic Controllers Low-Bleed	$175 to $350 per device	125 to 300 Mcf/year	$500 to $1,900 per year	< 0.5 – 1 year
Pneumatic Controllers No-Bleed	$10,000 to $60,000 per device	5,400 to 20,000 Mcf/year	$14,000 to $62,000 per year	< 2 years
Pipeline Maintenance and Repair	Varies widely	Varies widely but significant	Varies widely by significant	< 1 year
Vapor Recovery Units	$36,000 to $104,000 per device	5,000 to 91,000 Mcf/year	$4,000 to $348,000 per year	0.5– 3 years
Leak Monitoring and Repair	$26,000 to $59,000 per facility	30,000 to 87,000 Mcf/year	$117,000 to $314,000 per facility per year	< 0.5 years

Note: Profit includes revenue from deployment of technology plus any O&M savings or costs, but excludes depreciation

Source: Natural Resources Defense Council, "Leaking Profits," 2012.

If these technologies are as cost-effective as their proponents claim, why aren't companies using them more often? There are several possible explanations. First, while many technologies pay for themselves in three years or less, this may entail a lower rate of return than companies expect from other investments. Companies' internal hurdle rates may preclude investment in some emissions control technologies. In addition, there are misaligned incentives throughout the natural gas industry. While a vertically integrated company, one that controlled all aspects of natural gas production from drilling through distribution, would seize on opportunities to reduce leaks and increase profits, there are few examples of such integration. With thousands of companies providing services like drilling wells and building pipelines, the companies that sell natural gas do not often control the gas as it moves from the ground to its point of combustion. Service providers often do not have the incentive to minimize methane leakage, as they will see few, if any, of the benefits. While some gas majors are working to correct this market inefficiency, there is a clear opening for policymakers to influence the workings of the market in a way that would benefit industry as a whole, as well as the environment. A number of options available to Congress are listed in the summary, above. Natural gas customers, and Americans concerned about wasting domestic energy resources, should demand nothing less.

The natural gas stepping stone

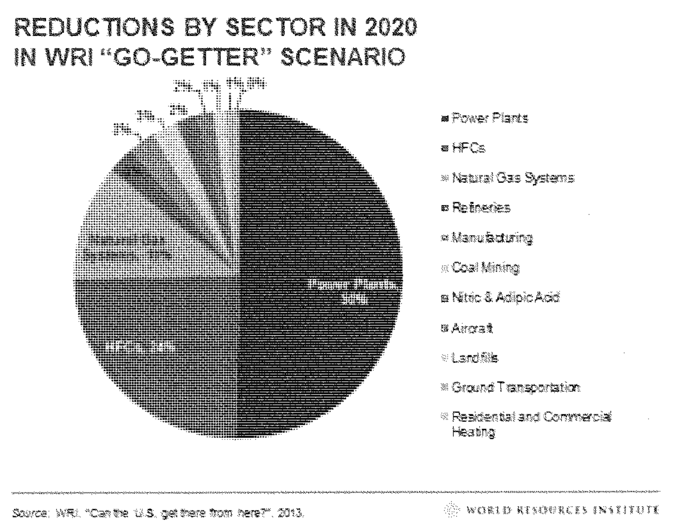
A 1% leakage rate would ensure that fuel switching from coal or diesel to natural gas is a net positive for the climate, but even eliminating methane leaks altogether would not make natural gas a long-term solution for reaching our climate goals. Natural gas may be cleaner than coal at the point of combustion, but merely being cleaner than the dirtiest fossil fuel is a low bar to clear.[26] Natural gas, like coal and oil, is a fossil fuel, and burning it still produces unsustainable levels of CO_2. Natural gas can be an initial step toward a low-carbon future, but it cannot be the dominant source of energy (even displacing coal) for more than another 20 years, at most.

Scientists have been warning for years about the dangers of exceeding a global temperature increase of 2 degrees Celsius above pre-industrial levels. With every degree of temperature change, there will be increasingly more severe impacts, for example from rising sea levels to increasing frequency and intensity of severe weather, significantly altering the way of life for people around the world. There is also the increased risk of abrupt and irreversible changes in the climate system. To reduce the risk of such catastrophic levels of warming, developed countries would have to reduce emissions 80-95% below 1990 levels by 2050, with emissions from

[26] For comparative emissions rates of coal, oil, and gas when burned to generate electricity, see http://www.eia.gov/tools/faqs/faq.cfm?id=74&t=11.

developing countries in all regions deviating substantially from their baselines. Clearly, natural gas alone is not the answer for achieving reductions of this magnitude, especially when previous analysis has determined that the electricity sector (along with natural gas systems) is the source of some of the most cost-effective ways to reduce GHG emissions.[27]

Figure 4: GHG Emissions Reductions by Sector in "Can the U.S. Get There from Here?"



There is an interesting new precedent for how to treat natural gas-fired power generation under an aggressive emissions reduction regime. Regulators in Massachusetts recently approved the construction of a natural gas power plant that will have to comply with the state's Global Warming Solutions Act, which mandates state-wide emissions reductions of 80% below 1990

[27] See, for example, http://www.wri.org/publication/can-us-get-there-here. Emissions reduction opportunities in the power sector include, but are not limited to, supply-side efficiency, demand-side efficiency, combined heat and power, fuel switching, increased renewable generation, and improved dispatch of low-carbon energy sources.

levels by 2050.[28] The permit conditions for the power plant require it to reduce or offset an increasing fraction of its GHG emissions, ultimately reducing its emissions by 80%, relative to the plant's expected start date of 2016, before the power plant is retired in 2050. The state offered the plant's operator flexibility in how the emissions reductions are achieved, including the use of carbon dioxide capture and storage (CCS) or other on-site emissions reduction options, or market-based approaches such as renewable energy certificates or allowances from the Regional Greenhouse Gas Initiative. The plant's useful life of 34 years will provide Massachusetts with time to ramp up its renewable energy capacity while decreasing its reliance on fossil-fired electricity generation.

Viewing energy infrastructure through a climate lens

The example of the natural gas-fired power plant in Massachusetts is instructive, as it demonstrates one way of factoring climate considerations into infrastructure decisions. The math is straightforward: natural gas without CCS or other emissions constraints cannot comprise more than a small fraction of the U.S. energy mix in the low-carbon economy we need to reach by the middle of this century. Internalizing that reality is critical for governments and private companies alike, if we are to avoid stranding expensive, high-emitting infrastructure assets while avoiding dangerous levels of warming.

Some of the largest companies in the world are starting to move in this direction, leaving policymakers to play catch-up. Major corporations as diverse as ExxonMobil, Wal-Mart, Google, and Wells Fargo have disclosed that they are factoring an internal carbon price as high

[28] For more information, see http://www.mass.gov/eea/pr-2014/salem-approval.html and http://www.nytimes.com/2014/02/21/business/energy-environment/massachusetts-approves-a-gas-power-plant-with-an-expiration-date.html?hpw&rref=science.

as $60 per ton of CO_2 into their decision-making.[29] Many of these companies also have their own internal GHG emission reduction targets. These are not necessarily the companies one would consider to be leaders in the fight against climate change; rather, they acknowledge the risks that warming poses to their operations and their bottom line, and they anticipate a world with binding carbon constraints.[30] Getting out ahead of the curve is simply good for business.

Smart climate policy is indisputably compatible with smart economic policy. Reducing methane emissions from leaky infrastructure is good for business. And numerous studies have made the case that inaction on climate change will be more expensive than taking action now to mitigate GHG emissions. Taken together, these arguments point to the need to take climate considerations into account when making investment decisions on long-lasting energy infrastructure. Power plants, pipelines, and other energy infrastructure are designed to last for decades. For Congress to provide the certainty, through comprehensive climate legislation, that unchecked GHG emissions will no longer be tolerated, would ensure that companies take all relevant factors into account when making both short- and long-term investment decisions.

[29] For the full report from CDP, see http://big.assets.huffingtonpost.com/22Nov2013-CDP-InternalCarbonPriceReprt.pdf.
[30] Many companies with international operations are already dealing with explicit or de facto prices on GHG emissions. A recent study found that 66 countries, responsible for 88% of GHG emissions, have legislation in place to reduce those emissions. For more information, see http://www.globeinternational.org/studies/legislation/climate.

Mr. WHITFIELD. Thank you, Mr. Obeiter. Next is Mr. Black, who used to run the Energy and Commerce Committee, so he is recognized for 5 minutes.

STATEMENT OF ANDREW J. BLACK

Mr. BLACK. Thank you, and good morning. I am Andy Black, president and CEO of the Association of Oil Pipe Lines. AOPL represents the owners and operators of energy liquid pipelines which benefit American workers and consumers. Americans use pipelines today to fuel their vehicles, heat their homes, harvest their crops, manufacture consumer goods, and more. In just 2012 pipelines transported 14.1 billion barrels of crude oil, refined products, and natural gas liquids across 185,000 miles of pipelines Nearly every gallon of gasoline consumers put in their vehicles travels at some point through a pipeline.

Pipelines allow American consumers to benefit from new crude oil production in the U.S. and Canada. Pipelines are also transporting growing supplies of U.S. natural gas liquids to chemical and plastic manufacturing facilities here in the U.S., which is creating new good paying jobs for American industrial workers.

Pipelines are the least expensive, most reliable, and safest mode of transporting liquid energy. For example, shipping by rail costs and average of two to three times more than by pipeline, according to EIA. In 2012 99.9998 percent of the products transported by liquid pipelines reached their destination safely. This safety record is a natural outcome of the major financial investment pipeline operators make in safety each year.

In 2012 operators spent more than $1.6 billion on pipeline integrity management. That is evaluating, inspecting, and maintaining their pipelines. The result is that over the last decade liquid pipeline incidents are down over 60 percent, and volumes released by pipelines are down more than 45 percent. The industry recently launched the Pipeline Safety Excellence Initiative to take these safety efforts to the next level.

Today pipelines operate in highly competitive transportation markets, competing vigorously against other pipeline operators, and operators of railroads, trucks, and barges. New and expanded pipeline infrastructure is essential to delivering the benefits of America's energy renaissance to U.S. consumers and workers.

AOPL members have made substantial investments to link new production and supply sources to refining and consuming markets. Pipeline operators have been constructing new pipelines, reversing pipelines, converting pipelines from one type of product service to another, and expanding the capacity of existing pipelines. More than 10,000 miles of liquid pipelines have been placed into service in just the last 4 years.

The importance of pipelines was underscored by what happened in propane markets this winter. As you have heard, propane storage inventory levels in the Midwest downstream of pipelines began this fall at abnormally low levels. Then large supplies of propane were needed to dry crops after an abundant and wet harvest. Next the Midwest and Northeast needed considerable supplies of propane during a winter that started early, and has been very cold. Liquid pipelines were asked to help, and they responded. Pipeline operators coordinated with government, asked shippers of other products to voluntarily defer shipment so that more propane could be shipped, made tariff filings at FERC to facilitate additional shipments, and issued alerts to shippers about unused and available pipeline capacity.

This winter's propane supply issues were not the result of inadequate pipeline infrastructure. There is, and will be, enough pipeline capacity to transport propane supplies to where they are needed. Like FedEx or UPS delivering packages for others, pipelines transport energy products for shippers, who own the products being shipped, and decide when they are to be shipped.

While pipeline service is available to shippers year round, propane shippers do not ship consistent amounts of propane throughout the year. Pipeline capacity exists during off peak times to help propane shippers ensure field supplies are sufficient to meet seasonal needs. If propane market participants want to adjust their supply patterns by shipping more pipeline offseason, more propane offseason to fill downstream storage, pipeline operators are ready. And if shipper expressed a need for new service by committing to use pipelines, pipeline operators will respond by adding new pipeline capacity.

Government can help ensure the availability of adequate pipeline infrastructure. It is essentially that States make timely decisions on siting requests for pipelines, that Federal agencies process permits needed for construction, that FERC policies support new investment, and, of course, that the State Department efficiently decides upon requests for presidential permits for facilities crossing our border.

The recent State Department analysis of Keystone XL found that alternative modes of transportation would result in higher costs to shippers, and more crude oil released in the environment. The high profile debate on Keystone XL has shown that more and more Americans recognize the benefits to consumers and workers of pipeline infrastructure. I want to thank the subcommittee for its interest in Keystone XL, and in pipeline infrastructure generally, including by holding this hearing today. Thank you.

[The prepared statement of Mr. Black follows:]

Testimony of Andrew J. Black, President and CEO, Association of Oil Pipe Lines (AOPL) Before the Subcommittee on Energy and Power, U.S. House of Representatives "Benefits of and Challenges to Energy Access in the 21st Century: Fuel Supply & Infrastructure" March 6, 2014

Liquid pipeline infrastructure across the United States benefits American consumers and workers. In 2012, liquid pipelines transported 14.1 billion barrels of crude oil, refined products and natural gas liquids across 185,000 miles of pipeline. Americans benefit from liquids pipelines to heat their homes, fuel their vehicles, harvest their crops, manufacture consumer goods, and more. Nearly every gallon of gasoline American consumers put into their vehicles travels at some point through a liquid pipeline. Liquids pipelines allow American consumers to benefit from new U.S. crude oil production. Liquids pipelines are transporting growing supplies of U.S. natural gas liquids to new chemical and plastics manufacturing facilities in the U.S. and creating new, good-paying jobs for American industrial workers.

Pipelines are the least expensive, most reliable, and safest mode of transporting liquid energy. In 2012, 99.9998% of the crude oil, petroleum products, and natural gas liquids transported by pipeline reached their destination safely. A recent Department of State analysis of the Keystone XL pipeline project estimated that alternative modes of transportation would result in 2.4 to 9.0 times more crude oil released to the environment each year compared to that pipeline. The safety record of pipelines is a natural outcome of the major financial investment pipeline operators make in pipeline safety each year. In 2012, pipeline operators spent more than $1.6 billion on pipeline integrity management evaluating, inspecting and maintaining their pipelines. The result is that over the last decade, liquid pipeline incidents are down over 60 percent and volumes released from pipelines are down over 45 percent.

Pipelines are also the most cost-effective form of energy transportation infrastructure. The U.S. Energy Information Agency (EIA) reports that shipping crude by rail costs an average of two to three times more than by pipeline. There is a role for rail transportation of crude oil and petroleum products depending upon the route, availability of pipeline capacity, time horizon or specific customer needs. Liquid pipeline operators compete vigorously against other pipeline operators and railroads, trucks, and barge operators that also transport energy liquids.

New and expanded pipeline infrastructure is essential to delivering the benefits of America's energy renaissance to U.S. consumers and workers. AOPL members have made substantial investments to link new production and supply sources to refining and consuming markets. Pipeline operators have been constructing new pipelines, reversing pipelines, converting pipelines from one type of product service to another, and expanding the capacity of existing pipelines by adding horsepower to pumping stations. More than 10,000 miles of new liquids pipelines have been placed into service in the last four years.

Today's hearing will touch on the role of pipelines transporting propane to the Midwest and Southeast. Pipelines transport propane on behalf of shippers who purchase propane at supply hubs and distribute it in their local markets. Pipeline operators earn revenues by transporting product for shippers, and thus have every incentive to ship product tendered for transportation on their systems. This winter, operating within the requirements of federal regulation and contract agreements, liquid pipelines responded to the need for additional propane shipments. Pipeline operators stand ready to work with propane market participants to facilitate the delivery of sufficient propane supplies in the future. Pipeline capacity exists, especially during off-peak times, to help ensure that fuel supplies are sufficient to meet seasonal needs.

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Testimony of

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President and CEO
Association of Oil Pipe Lines (AOPL)

Before

Subcommittee on Energy and Power
Committee on Energy and Commerce
U.S. House of Representatives

"Benefits of and Challenges to Energy Access in the 21st Century:
Fuel Supply and Infrastructure"
March 6, 2014

I am Andy Black, President and CEO of the Association of Oil Pipe Lines (AOPL). AOPL represents the owners and operators of energy liquids pipelines. I applaud the Subcommittee for its continued interest in energy infrastructure, and for holding this hearing. Thank you for the opportunity to discuss the role of pipeline infrastructure in fuel supply.

Liquid pipeline infrastructure across the U.S. benefits American consumers and workers. Pipelines are the safest and least-expensive mode of energy transportation over land. During the recent local propane shortages, pipeline operators worked with propane shippers and the federal government to facilitate the delivery of additional propane supplies. Liquid pipeline operators are expanding the nation's infrastructure network to move energy from new production and storage areas to customers. Pipeline capacity also exists, especially during off-peak times, to ensure that fuel supplies are sufficient to meet seasonal needs. Government can help ensure the availability of adequate pipeline infrastructure by avoiding unnecessary delays in regulatory approvals and continuing to provide a transportation rate structure that supports new pipeline infrastructure investment.

Liquid Pipeline Infrastructure Benefits American Consumers and Workers

Liquids pipelines transport the crude oil, refined products, and natural gas liquids that American consumers and workers use every day to lead their lives and fuel their jobs. In 2012, liquid pipeline operators delivered more than 14.1 billion barrels of crude oil and petroleum products across more than 185,000 miles of pipeline in the U.S.

Liquids pipelines transport crude oil from production areas across the U.S. and Canada to storage hubs and refineries. Separate liquids pipelines transport refined petroleum products (like gasoline, diesel fuel, jet fuel, home heating oil, and propane) from refineries to local distribution terminals. Still other liquids pipelines deliver natural gas liquids products (like ethane, butane, and propane) from production areas, to and from fractionation facilities, and on to U.S. consumers, manufacturers, and industrial users.

Americans benefit from liquids pipelines to heat their homes, fuel their vehicles, dry their clothes, harvest, and dry their crops, manufacture consumer goods, and more. Nearly every gallon of gasoline American consumers put into their vehicles travels at some point through a liquids pipeline. Liquids pipelines allow American consumers to benefit from U.S. crude production regions in Texas, North Dakota, California and states in between. Liquids pipelines are transporting growing supplies of natural gas liquids from new production areas in Pennsylvania, Ohio, and Texas to chemical and plastics manufacturing facilities in the U.S. and creating new, good-paying jobs for American industrial workers.

Pipelines Are the Safest, Least Expensive Energy Transportation Infrastructure

Pipelines are the least expensive, most reliable, and safest mode of transporting large volumes of energy liquids over long distances over land. In 2012 alone, 99.9998% of the crude oil, petroleum products, and natural gas liquids transported by pipeline reached their destination safely. The Final Supplemental Environmental Impact Statement completed by the U.S. Department of State for the Keystone XL pipeline found that alternative modes of transportation would result in 2.4 to 9.0 times more crude oil released to the environment each year compared to that pipeline. Denying the XL Presidential Permit and relying upon non-pipeline transportation infrastructure would result in the additional release of between 29,778 and 172,830 gallons of crude oil to the environment.

The safety record of pipelines is a natural outcome of the major financial investment pipeline operators make in pipeline safety each year. In 2012, pipeline operators spent at least $1.6 billion on pipeline integrity management evaluating, inspecting and maintaining their pipelines. The result is that over the last decade, liquid pipeline incidents are down over 60 percent and volumes released from pipelines are down over 45 percent.

While pipeline infrastructure is the safest mode of energy transportation, liquids pipeline operators remain focused on continuous improvement with the ultimate goal of zero incidents. Pipeline operators are undertaking a number of industry-wide initiatives to improve pipeline safety performance. In 2012, pipeline operators adopted a set of industry-wide safety values, including the goal of zero incidents. Industry-wide, operator-led safety groups continue to develop new recommended practices and safety improvement tools. In 2014, the liquid pipeline industry launched the *Pipeline Safety Excellence* initiative to take these safety efforts to the next level. The effort includes public sharing of our safety performance record and strategic initiatives addressing a number of key safety issues.

Pipelines are also the most cost-effective form of energy transportation infrastructure and the ideal method of transporting large volumes of energy over long distances. The U.S. Energy Information Agency (EIA) reports[1] that shipping crude by rail costs an average of two to three times more than by pipeline. There is a role for rail transportation of crude oil and petroleum products depending upon the route, availability of pipeline capacity, time horizon or specific customer needs. Liquid pipeline operators compete vigorously against other pipeline operators and railroads, trucks, and barge operators that also transport energy liquids.

Recent Propane Issues

The importance of pipelines and other midstream transportation infrastructure was underscored by what has happened this winter in propane markets. Propane inventory levels in the Midwest, downstream of pipelines, began this fall at abnormally low levels, according to the EIA[2]. This set the stage for the most recent supply difficulties. Large supplies of propane were needed this fall to dry crops after a harvest that was late, abundant, and often wet. Following this increased agricultural demand, the Midwest and then needed considerable supplies of propane for heating during a winter that has been early, long and often very cold. The result was more local and regional concerns with downstream propane supply than has been the case in many recent years.

An existing network of liquid pipelines delivers propane and other natural gas liquids from storage hubs in Texas and Kansas to distribution facilities across the South, Midwest and Upper Midwest. The Dixie dedicated propane pipeline runs from Texas across the south to North Carolina. Enterprise TE Products Pipeline (TEPPCO) delivers refined petroleum products and natural gas liquids, including propane, from Texas north to southern Illinois and then east to Ohio, before continuing on as a propane

[1] EIA Today In Energy, July 26, 2012, http://www.eia.gov/todayinenergy/detail.cfm?id=7270
[2] EIA Propane Situation Update, February 26, 2014, http://www.eia.gov/pressroom/presentations/propane_02262014.pdf

pipeline into Pennsylvania and New York. The Mid-America Pipeline (MAPL) delivers propane and natural gas liquids from a storage hub in Kansas to Wisconsin and Minnesota. The Kinder Morgan Cochin pipeline delivers propane and natural gas liquids southward from Canada down across the Upper Midwest arcing below Lake Michigan and then up into the State of Michigan. ONEOK Partners also operates natural gas liquids pipelines in the Midwest.

It is important to recognize that pipeline operators do not own the products shipped on their systems. Like FedEx or UPS delivering the packages of others, pipeline operators transport energy products for shippers, who own the products being shipped. A pipeline earns revenue by charging a rate for the transportation services it provides to shippers. Thus, pipeline operators have every financial incentive to make deliveries, including deliveries of propane.

The rates, terms and conditions of shipping on an interstate liquid pipeline are regulated by the Federal Energy Regulatory Commission (FERC). Such matters as how much a pipeline charges a shipper to make a shipment and the order in which a product is shipped relative to other shippers' products are set forth in a tariff on file with the FERC.

This winter, when local propane supplies fell, concern naturally focused on the reasons and potential solutions. Pipeline operators were asked to help, and they responded. TEPPCO asked shippers of other refined products on its pipeline system to voluntarily defer shipments so that propane shippers could ship propane from Mont Belvieu, Texas, and some shippers agreed. ONEOK filed several tariffs at FERC to facilitate the delivery of additional propane supplies from Conway, Kansas to markets. Kinder Morgan submitted a tariff filing at FERC to facilitate the shipment of additional propane supplies and alerted shippers about available capacity on the Cochin Pipeline from Alberta. Meanwhile, Enterprise's Mid-America Pipeline, a dedicated propane pipeline, continued to run at maximum capacity. When officials of the Department of Energy initiated regular calls to coordinate efforts to ease the crisis, AOPL participated fully and worked with its members to help address supply and transportation issues.

FERC issued a one-week emergency order[3] that was effective February 7-14, directing TEPPCO to prioritize shipments of propane from Mont Belvieu, Texas to locations in the Midwest and Northeast in order to alleviate propane supply concerns in those regions. TEPPCO voluntarily agreed to a one-week extension of the emergency order through February 21. TEPPCO complied with the emergency orders and prioritized propane transportation requests during this period. I understand from public reports an additional 500,000 barrels of propane was injected into TEPPCO, at the request of propane shippers, during the first week that the FERC emergency order was in effect. AOPL does not know whether any additional propane was injected at the request of propane shippers during the second week of the emergency order.

Minimizing Future Energy Shortages

This situation is not the result of inadequate pipeline infrastructure. There is enough pipeline capacity to transport propane supplies to where they are needed. Business decisions regarding the scheduling of propane supply shipments and filling downstream storage are made primarily by propane market participants and not by pipeline operators. Pipeline operators offer propane transportation service to shippers year-round. However, propane shippers do not ship consistent amounts throughout the year. Generally, propane shippers ship less propane during late winter, spring, and early summer, and more propane just before fall harvests and into winter. While decisions about shipping propane and filling downstream storage might be easy to second guess in hindsight, they are complex and involve many

[3] *See Enterprise TE Products Pipeline Company, LLC*, 146 FERC ¶ 61,076 (2014) ("Order Directing Priority Treatment"); *Enterprise TE Products Pipeline Company, LLC*, 146 FERC ¶ 61,085 (2014) ("Order Extending Priority Treatment"). Effectively, the orders overrode the rules in TEPPCO's tariff on apportionment of pipeline capacity.

factors best explained by propane market participants. Nevertheless, propane supply concerns can in large measure be alleviated by increased off-season purchases by propane market participants in supply areas, with advance shipment to consuming areas and injection of these supplies into storage. The pipeline industry stands ready to accommodate that shift in supply planning patterns by propane market participants, should they elect to do so.

Pipeline operators and AOPL have a strong history of working with shippers and government before and during times of crisis so that American consumers and workers can continue to receive the products they need. After Hurricane Sandy produced local flooding and power outages causing reduced supplies of gasoline and other refined products in New Jersey, pipeline operators worked with government and local stakeholders to restore service. After Hurricane Katrina knocked out power for pipelines and caused concerns about supplies in the Carolinas and mid-Atlantic, pipeline operators worked with government at all levels to return pipelines to service. These rare crises demonstrate the importance to Americans of maintaining a robust and reliable pipeline network.

Importance of New Pipelines

One essential element to assure continued sufficient supply of energy liquids is adequate pipeline capacity, including the building of new pipelines. AOPL members have been responding to the North American energy revolution by making substantial investments needed to link new supply sources to refining and consuming markets. Pipeline operators have been constructing new pipelines, reversing pipelines, converting pipelines from one type of product service to another, and expanding the capacity of existing pipelines by adding horsepower to pumping stations. More than 10,000 miles of new liquids pipelines have been placed into service in the last four years, according to the U.S. Department of Transportation[4]. These new pipelines are enabling Americans to access growing production of crude oil from Texas to Alberta, growing production of natural gas liquids from North Dakota to Texas to Ohio, and increases in refining and fractionation capacity.

Pipeline shippers play a huge role in assuring the availability of needed pipeline capacity. Most new pipeline capacity projects are supported by long-term agreements between pipeline operators and shippers to assure the use of proposed pipelines and enable financing. As transportation service companies moving products for a fee, pipeline operators have every incentive to maximize shipments by their customers. When shippers express their need for service by committing to use pipelines, pipeline operators respond.

Government policies also play a huge role in assuring availability of needed pipeline capacity. Thankfully, the Interstate Commerce Act and FERC policies today allow liquid pipeline operators to respond quickly to changing needs by propane and other shippers. FERC needs to continue to honor long-term transportation agreements between pipeline operators and shippers to ensure that needed new infrastructure can be built. It is essential that States make timely decisions on siting requests for pipelines, Federal agencies process permits needed for certain pipeline construction activities, and, of course, the U.S. Department of State efficiently grants Presidential Permits for pipeline facilities crossing our national borders.

This Subcommittee and Committee have been tremendous advocates of energy infrastructure, including pipelines. AOPL appreciates your attention to these issues with this hearing today.

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[4] Annual Report Mileage, U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=d731f5448a359310VgnVCM1000001ecb7898RCRD&vgnextchannel=3b6c03347e4d8210VgnVCM1000001ecb7898RCRD&vgnextfmt=print.

Mr. WHITFIELD. Thank you, Mr. Black. And, Mr. Hamberger, you are recognized for 5 minutes.

STATEMENT OF EDWARD R. HAMBERGER

Mr. HAMBERGER. Thank you, Chairman Whitfield, Chairman Upton, Ranking Member McNerney. Thank you for the opportunity to appear before you on behalf of the Association of American Railroads. Our members account for the vast majority of the freight railroad mileage, employees, tonnage in Canada, Mexico, and the United States. The transportation of energy products is a central focus of this network, and we are proud of the role we play. By delivering coal to power plants, ethanol to fuel blenders, crude oil to refiners, propane to local distributors, frack sand and steel pipe to natural gas extractors, railroads are indispensable in our nation's ongoing quest to achieve greater energy security and higher domestic energy production.

But that would not be the case if, back in 1980, your predecessors had not passed the Staggers Rail Act, removing strangling regulation and releasing $550 billion of private sector investment. By leading that fight, this committee enabled the rail tonnage to double. The accident rate is down 79 percent, and rates are actually down 42 percent from 1980. The massive investments, and I emphasize they are private sector investments, would not have occurred, were it not for the leadership of this committee, and that Staggers Rail Act has made our system the envy of the world. Had you not done the right thing back in 1980, we would not be the envy of anyone today.

In recent years railroads have seen dramatic increases in demand to transport crude oil. As recently as 2008, class one U.S. railroads originated just 9,500 car loads of crude oil. In 2013, that number is 410,000 car loads, approximately 11 percent of the U.S. crude oil production. And that is good news not just for the railroad industry, but, as you said, Mr. McNerney, for the economy as a whole, as we begin to produce more than we import.

My thesis today is that our nation cannot take full advantage of our new crude oil resources without a safe, efficient, financially healthy freight rail industry. But a very close corollary to that is that our nation cannot reach energy independence without a safe, efficient, financially health pipeline industry, barge and towing industry, and yes, my good friend Shorty, a tank truck industry.

The question that we have been hearing recently, because of some high profile accidents, is can railroads, in fact, move crude oil safely? I am here to tell you the answer to that question is yes. Our safety record is 99.98 percent of the time we get from origin to destination without a spill. That is pretty good, not good enough, and we are going to continue to try to get to 100 percent. And to that end, we reached an agreement just two weeks ago with Secretary of Transportation Foxx to implement a series of voluntary action items that we will take to try to improve our safety record. These include more frequent track inspections than required by regulation, enhanced braking systems, speed restrictions beyond those in the regulations, and the use of a sophisticated routing model to assess the safest and more secure routes.

These steps are aimed primarily at accident prevention, but the next step in dealing with risk is mitigation. And there we are recommending new tank car standards, including a thicker tank car, and a jacket around the tank cars to help them in the mitigation. We also believe that existing tank cars need to be retrofitted, or phased out of service of flammable liquids.

Emergency response is the third bucket of activities, very critical as well. Last year we trained 22,000 emergency responders around the country, and we have stepped up, again, in the agreement with Secretary Foxx, to develop a very specialized emergency response training module at our training center in Pueblo, Colorado, the emergency response training center where we have hands-on experience for emergency firefighters.

You can't talk about energy in the United States without talking about coal. U.S. coal production is focused in a relatively small number of States, but coal is consumed in large amounts all over the country, made possible because the U.S. has the world's best, most efficient, and comprehensive coal transportation system, with freight railroads leading the way. In 2012 railroads delivered 577 million tons of coal to our nation's electric utilities, equal to more than 70 percent of the total coal deliveries to power plants. That happens to be down 23 percent from our peak in 2008.

The lure of higher coal exports to Asia is the main impetus for plans to build new bulk export terminals in the Pacific Northwest. For China and India, if consuming more coal means cheaper and more reliable electricity for the hundreds of millions of people in those countries who currently don't have that electricity, then consuming more coal is what they will do. I submit to you that this coal could be supplied by U.S. coal producers and U.S. coal transporters, who operate under the world's most stringent safety and environmental standards, or it could be supplied by producers and transporters in other countries, who operate under more lax standards.

I apologize for running over, Mr. Chairman. Thank you for the opportunity to be here today.

[The prepared statement of Mr. Hamberger follows:]

TESTIMONY OF

EDWARD R. HAMBERGER

PRESIDENT & CHIEF EXECUTIVE OFFICER

ASSOCIATION OF AMERICAN RAILROADS

BEFORE THE

UNITED STATES HOUSE OF REPRESENTATIVES

COMMITTEE ON ENERGY AND COMMERCE

SUBCOMMITTEE ON ENERGY AND POWER

HEARING ON BENEFITS OF AND CHALLENGES TO ENERGY ACCESS IN THE 21ST CENTURY: FUEL SUPPLY AND INFRASTRUCTURE

MARCH 6, 2014

On behalf of the members of the Association of American Railroads, thank you for the opportunity to discuss the transportation of energy products by rail. AAR members account for the vast majority of freight railroad mileage, employees, and traffic (including energy products) in Canada, Mexico, and the United States.

The growth and vitality of our nation have always been closely tied to transportation. Today, our nation's transportation networks are, in aggregate, far and away the best in the world, providing both a substantial competitive advantage for our farmers and manufacturers in the marketplace and a means to significantly improve the standard of living for all of us.

The transportation of energy products is a central focus of our transportation networks, and railroads are proud of the critical role they play. By delivering (among many other things) coal to power plants, ethanol to fuel blenders, crude oil to refiners, and frac sand and steel pipes to natural gas extractors, railroads are indispensable in our nation's ongoing quest to achieve greater energy security and higher domestic energy production.

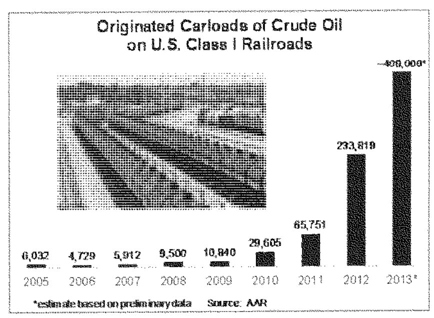
Back in 1980, the Committee on Interstate and Foreign Commerce — the precursor to today's Committee on Energy and Commerce — was the driving force behind passage of the Staggers Rail Act. It's no exaggeration to say that the Staggers Act, named after the chairman of the committee at the time, has turned out to be one of the most far reaching and successful pieces of transportation-related legislation in history.

By passing the Staggers Act, Congress recognized that America's freight railroads — the vast majority of which are private companies that operate on infrastructure that they own, build, maintain, and pay for themselves — faced intense competition for most of their traffic, but excessive regulation prevented them from competing effectively. To survive, railroads needed a common-sense regulatory system that allowed them to act like most other businesses in terms of managing their assets and pricing their services. Since it was passed, average rail rates have fallen 42 percent, train accident rates are down 79 percent, rail traffic volume has nearly doubled, and railroads have reinvested $550 billion — their own funds, not government funds — back into their systems. These massive investments have created a freight rail network that is the envy of the world.

Had this committee not done the right thing back in 1980, the U.S. rail industry today probably would not be the envy of anyone. Rather than providing a huge competitive advantage for U.S. businesses, huge savings for consumers, and strong support for our nation's economic recovery, the rail industry would be much smaller, much less reliable, and much less productive. Below I talk about "shale oil" and the recent huge increase in crude oil traffic on railroads. Prior to the Staggers Act, the rail industry would never have been able to handle something like that. All of us owe this committee our thanks.

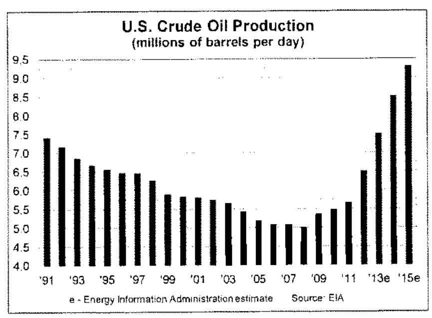
Below I also discuss railroads' role in many energy markets and point out some steps policymakers can take to help ensure that railroads can continue to serve these markets safely, reliably, and cost-effectively for many years to come.

The Transportation of Crude Oil by Rail



All of you are probably aware that, in recent years, railroads have seen dramatic increases in demand to transport crude oil. As recently as 2008, Class I U.S. railroads (the seven largest railroads) originated just 9,500 carloads of crude oil. By 2012, carloads had surged to nearly 234,000. Final numbers for 2013 aren't in yet, but we estimate that crude oil originations on Class I railroads in 2013 were around 408,000 carloads and terminations were around 434,000 carloads.[1] In 2013, crude oil accounted for about 1.4 percent of total originated carloads on Class I railroads, up from just 0.03 percent in 2008.

The huge increase in rail crude oil volume is a function of the massive, salutary development of North American oil resources in recent years, especially "shale oil." U.S. crude oil production peaked in 1970 at 9.6 million barrels per day, but by 2008 it had fallen to 5.0 million barrels per day as depletion of older fields outpaced new production. Over the past couple of years, however, technological advances in the extraction of shale oil, along with relatively high crude oil prices, have led to sharply higher U.S. crude oil production. The Energy Information Administration (EIA) states that production rose to an average of 6.5 million barrels per day in 2012 and 7.5 million barrels per day in 2013. Barring unforeseen circumstances, deposits of crude oil in shale formations across the country will continue to be developed. As a result, the EIA projects that U.S. crude oil production will increase to 8.5 million barrels per day in 2014 and 9.3 billion barrels per day in 2015.

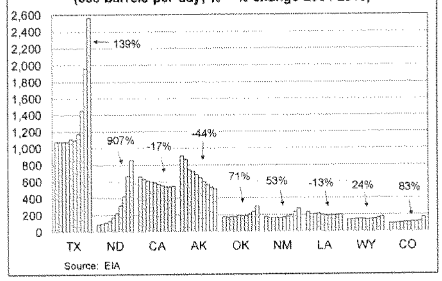


Much of the recent increase in crude oil production has occurred in North Dakota, where crude oil production rose from an average of 81,000 barrels per day in 2003 to 940,000 barrels per day by the fall of 2013, making North Dakota the second-largest oil producing state. Crude oil output in Texas, the top U.S. producer, was around 1.1 million barrels per day for years until 2009. Since then, output has skyrocketed, exceeding 2.7 million barrels per day by late 2013.

[1] Originations do not exactly equal terminations because some crude oil that originates on U.S. Class I railroads might be delivered to U.S. short lines or to railroads in Canada for termination and because some crude oil that terminates on U.S. Class I railroads might originate on railroads in Canada or on U.S. short line railroads.

Assuming for simplicity that a rail tank car holds about 30,000 gallons (714 barrels) of crude oil, the approximately 408,000 carloads of crude oil originated by Class I railroads in 2013 equal around 800,000 barrels per day, or about 11 percent of U.S. crude oil production — up from virtually nothing just a few years ago.

Avg. U.S. Crude Oil Production by State: 2004-2013
(000 barrels per day; % = % change 2004-2013)



Source: EIA

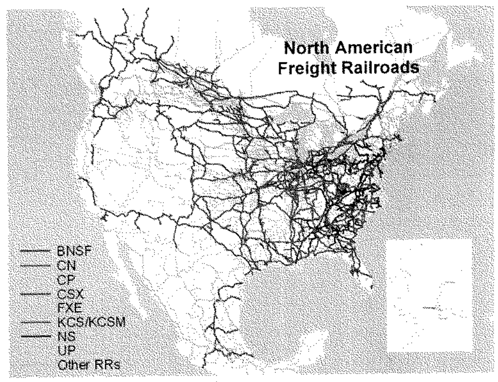
The development of shale oil represents a tremendous opportunity for our nation to move closer to energy independence. The widespread benefits this would entail include reduced reliance on oil imports from unstable countries whose interests do not necessarily match up well with our own; increased economic development all over the country; thousands of new well-paying jobs; tens of billions in savings in our nation's trade deficit every year; and substantial amounts of new tax revenue for governments at all levels. Rail has a critical role in delivering these crucial benefits to our country.

<u>Advantages to Our Nation of Transporting Crude Oil by Rail</u>

In addition to the critical fact that railroads provide transportation capacity in many areas where pipeline capacity is insufficient, railroads offer a number of other advantages for transporting crude oil:

- <u>Geographical Flexibility</u>. By serving almost every refinery in the United States and Canada, railroads offer market participants enormous flexibility to shift product quickly to different places in response to market needs.
- <u>Efficiency</u>. As new rail facilities are developed, railroads are involved at every step, helping facility owners decide where to locate assets and how to lay out rail infrastructure to maximize safety and efficiency.

- Responsiveness. Rail facilities can almost always be built or expanded much more quickly than pipelines and refineries can be. Essentially, railroads are the only transportation mode that can invest in facilities quickly enough to keep up with production growth in the emerging oil fields.



- Underlying Infrastructure and Equipment. Just over the past few years, railroads have invested tens of billions of dollars to replace and resurface tracks, buy new locomotives, build new terminals and track capacity, hire new employees, and take other steps to enhance their ability to transport crude oil.

Notwithstanding these attributes of rail, railroads recognize that if we are to continue down the path of energy independence, other transportation modes — including, of course, pipelines — have crucial roles to play.

Enhancing the Safety of Crude Oil by Rail

Our nation can't take full advantage of our new crude oil resources without railroads. But, at the same time, we have to remember how important it is to move the crude oil safely. From 2000 through 2013, a period during which U.S. railroads originated approximately 832,000 carloads of crude oil, more than 99.98 percent of those carloads arrived at their destination without a release caused by an accident. That's a very good safety record, but the railroads are committed to continuing to look for ways to be safer.

To that end, we are happy that we have been able to come to an agreement with U.S. Department of Transportation Secretary Foxx, with the assistance of Administrator Szabo of the Federal Railroad Administration (FRA) and Administrator Quarterman of the Pipeline and Hazardous Materials Safety Administration (PHMSA), on a series of measures to further enhance the rail industry's ability to safely meet the growing demand for crude oil transportation. These measures focus on prevention, mitigation, and response.

Under the agreement, tracks on which trains carrying large amounts of crude oil will be subject to more frequent track inspections, speed restrictions, and the use of a sophisticated routing model to assess the safest and more secure routes. These steps are aimed mainly at accident prevention. Railroads also help prevent accidents by reinvesting huge amounts to renew, upgrade, and expand their infrastructure and equipment. These investments will likely exceed $26 billion in 2014, more than ever before, as I discuss further below.

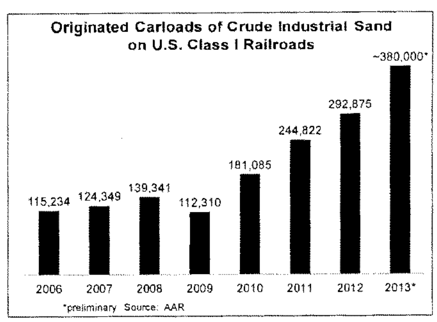
Railroads are also recommending a variety of ways, including the use of thicker shells, to make tank cars safer. This will help mitigate the consequences of accidents should they occur. For example, railroads support strengthening tank cars used to transport crude oil with thicker, 9/16th inch shells. Railroads also believe that tank cars used to haul crude oil should be equipped with a number of other features, including an outer protective "jacket," thermal protection, full-height head shields on the ends of cars, top fitting protections, and bottom outlet handles that provides greater protection in the event of a derailment. These features would make tank cars more robust. We also believe that existing tank cars that do not meet these higher standards should either be modified to meet the standards or aggressively phased out.

Emergency response is crucial too. Railroads already have extensive emergency response functions, which work in cooperation with federal, state and local authorities. More than 25 years ago, the AAR established what is now the Security and Emergency Response Training Center (SERTC), a world-class facility in Pueblo, Colorado. The SERTC has provided in-depth hazmat emergency response training to more than 50,000 people. In addition, as part of regular operations, railroads and communities develop and evaluate emergency response plans and train more than 20,000 emergency responders each year. The rail industry's commitment, announced on February 21, to spend approximately $5 million to assist communities to train specifically for crude oil incidents will help to minimize damage caused by crude oil releases.

The discussion of safety above is just a summary of the significant, comprehensive, and ongoing rail safety efforts related to crude oil. The AAR would be happy to provide more details on any of these efforts upon request. But you should know that, when it comes to safety, railroads are not just focused on crude oil. No matter the commodity railroads are hauling, nothing is more important than safety. We are a safe industry now, but we are always looking for ways to be even safer. We will continue to work with you, policymakers at DOT, FRA, PHMSA, and elsewhere, with rail industry suppliers, and with our customers in every industry we serve in a continuous effort to make tomorrow safer than today.

Other Key Rail Contributions to Domestic Petroleum-Related Production

Hydraulic fracturing, or "fracking," involves pumping a mixture of water, sand and chemicals down a well at high pressure to create thin cracks in the shale rock, thereby freeing oil and gas trapped inside and allowing it to be brought to the surface. Transporting large amounts of "frac sand" marks another important way that railroads are making critical contributions to our energy security and enhanced domestic energy production.



In 2009, U.S. Class I railroads originated just over 112,000 carloads of industrial sand, a broad category that includes frac sand. In 2013, railroads originated approximately 380,000 carloads of industrial sand. Frac sand is the primary driver behind this substantial increase. (A typical rail car of frac sand contains around 100 tons; a single horizontal well typically uses between 3,000 and 10,000 tons of sand, or the equivalent of 30 to 100 rail carloads.)

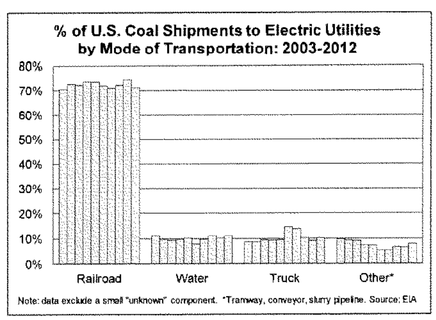
Railroads are also key players in the movement of iron ore, scrap steel, and other raw materials to steel plants that produce the pipes used in crude oil and natural gas production, and in the delivery of those pipes from steel plants to crude oil and natural gas production areas.

Railroads and Coal

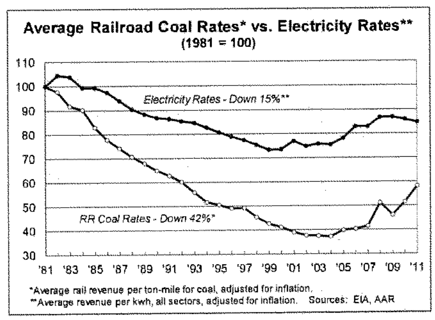
U.S. coal production is focused in a relatively small number of states, but coal is consumed in large amounts all over the country. This is possible because the United States has the world's most efficient and comprehensive coal transportation system, with railroads leading the way. Indeed, no single commodity is more important to America's railroads than coal. Coal accounted for 41.0 percent of rail tonnage and 21.6 percent of rail gross revenue in 2012.

Electricity Generation From Coal

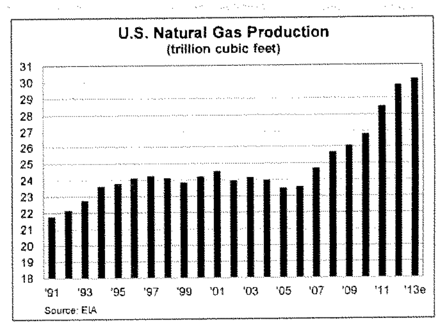
The vast majority of coal in the United States is consumed at coal-fueled power plants. Historically, coal has dominated U.S. electricity generation because it is such a cost-effective fuel choice. In fact, over time, cost-effective coal-fired electricity has generated immeasurable benefits to our economy and our standard of living, and freight rail is a big reason for that. In 2012, railroads delivered 577 million tons of coal to our nation's electric utilities, equal to more than 70 percent of total coal deliveries to power plants.



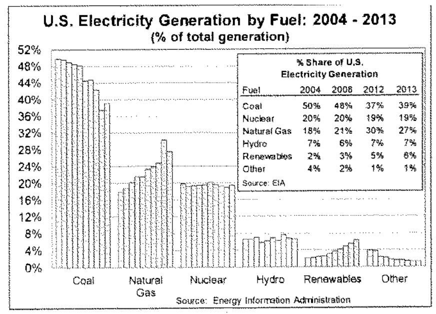
Revenue per ton-mile (RPTM) is a useful surrogate for rail rates. In 2011 (the most recent year for which RPTM data for coal are available), average RPTM for coal was 2.88 cents, by far the lowest such figure among major commodities carried by railroads. Average RPTM in 2011 for all commodities other than coal was 5.78 cents — double the comparable coal figure. Adjusted for inflation, coal RPTM was 42 percent lower in 2011 than in 1981. This means a typical coal shipper in 2011 could ship close to twice as much coal for what the shipper paid 30 years before. The average decline in rail coal rates over time is much greater than the average decline in the price of electricity over time, indicating that railroads are doing their part to keep electricity affordable for U.S. consumers.



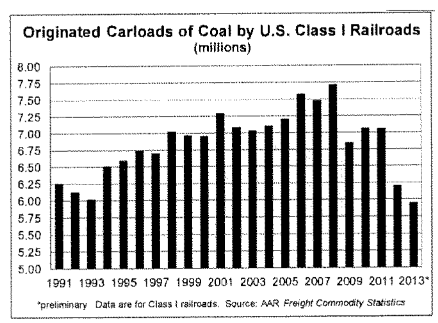
As discussed above, the "shale revolution" has led to higher U.S. rail carloads of crude oil and frac sand, but it's also led to sharply lower rail carloads of coal. That's because fracking and horizontal drilling have led to sharply higher U.S. natural gas production, which in turn has meant sharply lower natural gas prices to electric utilities. This has made electricity generated from natural gas much more competitive in the electricity marketplace relative to electricity generated from coal.



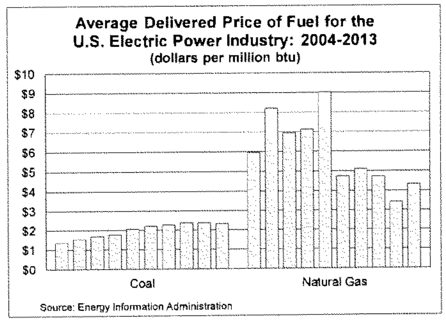
Consequently, natural gas's share of total U.S. electricity generation has surged in recent years, while electricity generated from coal has fallen correspondingly. The coal share of electricity generation was 50 percent or higher each year from 1980 through 2003 and 48 percent as recently as 2008, but was just 39% in 2013. The growth of renewable energy and increasingly stringent environmental constraints have also played important roles in coal's declining share of electricity generation.



Reduced electricity generation from coal in recent years has meant a big decline in rail carloads of coal. U.S. Class I railroads originated 6.2 million coal carloads in 2012, the lowest annual total since 1993; coal carloads dipped just below 6 million in 2013. That decline has been a tremendous challenge for railroads to deal with, but railroads understand that the competitive markets in which they operate are sometimes unforgiving.



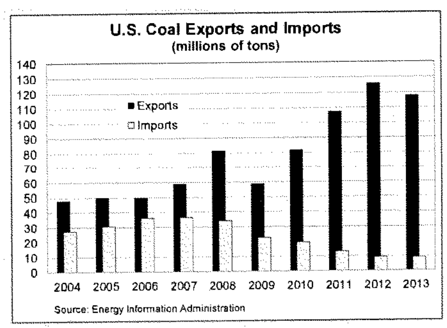
The recent decline notwithstanding, it's clear that coal-based electricity generation is not going to disappear any time soon. In 2013, natural gas's share of electricity generation fell for the first time in five years, in part because the price of natural gas to electricity generators rose, on average, nearly 27 percent in 2013 over 2012. The future of natural gas generation will depend largely on what happens to the price of natural gas; there is no guarantee it will stay as low as it has been in recent years. Meanwhile, the amount of electricity generated by nuclear power has been basically flat for years. Since few if any new nuclear plants will be coming on line in the foreseeable future, that's not likely to change. The share of total electricity generation attributable to non-hydroelectric renewable sources — primarily solar and wind — has doubled in the past five years, but in 2013 was still just 6.2 percent of total U.S. generation.



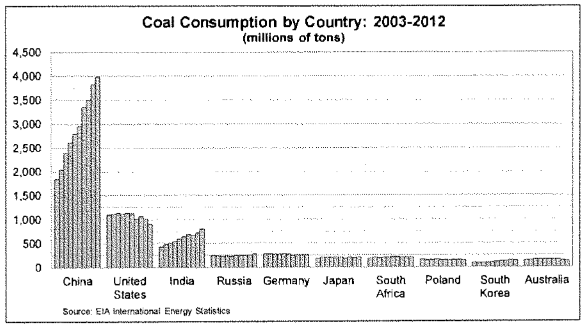
Given these facts, there is no realistic alternative for the United States other than to continue to rely heavily on coal-based electricity generation for many years to come. Railroads look forward to continuing to provide their utility coal customers with safe, reliable, and cost–effective service now and in the future.

U.S. Coal Exports

U.S. coal exports were a record 125.7 million tons in 2012. In 2013, they were down slightly to 117.7 million tons, but that was still the second-highest annual total in U.S. history. A significant portion of U.S. coal exports travels by rail.



As noted above, U.S. coal consumption, primarily for electricity generation, will almost certainly continue at high levels far into the future, albeit not necessarily at levels once seen. In some other countries, especially in Asia, coal consumption continues to grow rapidly. In 1980,



China accounted for approximately 16 percent of world coal consumption and the United States accounted for approximately 17 percent. In 2012, the U.S. share was down to 11 percent, but the China share was up to approximately 48 percent. Likewise, India's share has grown too, reaching nearly 10 percent in 2012. If current trends continue, within a few years China could be consuming as much coal as all the other countries in the world combined, and India will supplant the United States as the world's second largest coal consumer.

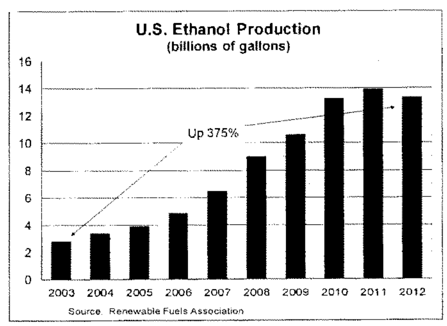
U.S. coal producers can compete with coal producers anywhere else in the world. Thus, U.S. coal producers are hopeful that coal exports will grow in the future, with Asia, especially China and India, seen as especially important potential markets. In 2012, U.S. coal exports to Asia were 32.5 million tons. U.S. coal exports to China in 2012 were just 10.1 million tons, and to India just 6.8 million tons — both miniscule percentages of total coal consumption in those countries.

The lure of higher coal exports to Asia is the main impetus for plans, as of this writing unfulfilled due to opposition by some in the environmental community, to build new coal export terminals in California or the Pacific Northwest. For China and India, if consuming more coal means cheaper and more reliable electricity for the hundreds of millions of people in those countries who currently don't have it, then consuming more coal is what they'll do. This coal could be supplied by U.S. coal producers and U.S. coal transporters, who operate under the world's most stringent safety and environmental standards, or it could be supplied by coal producers and transporters in other countries who operate under more lax standards. The fact is, coal producers in other countries are actively and aggressively pursuing exports to Asia and other markets. They know that U.S. coal is highly competitive and would love to see U.S. coal kept away from global markets. The United States can and should compete aggressively for these markets, and we can do it in a way that both benefits our economy and adheres to rigorous state and federal guidelines to protect the environment.

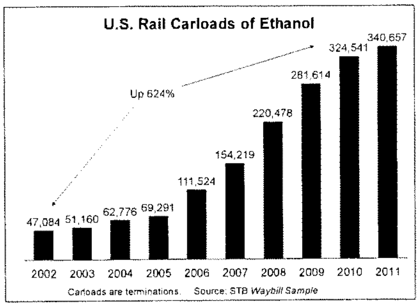
U.S. freight railroads have a long record of working cooperatively with communities in which they operate so that community concerns regarding safety are addressed. It would be no different for communities that see more train traffic related to expanded coal exports.

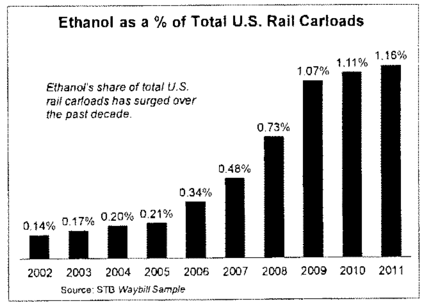
Railroads and Ethanol

The U.S. ethanol industry has seen tremendous growth. In 2012, U.S. ethanol production was approximately 13.3 billion gallons, a 375 percent increase over the 2.8 billion gallons produced in 2003.



Ethanol production is concentrated in the Midwest — where most of the corn that goes into ethanol production is grown — but many of the major markets for ethanol are on the East Coast, California, and Texas. Thus, large amounts of ethanol are transported from production to consumption areas. Railroads are the mode of choice, accounting for approximately 70 percent of ethanol transport.





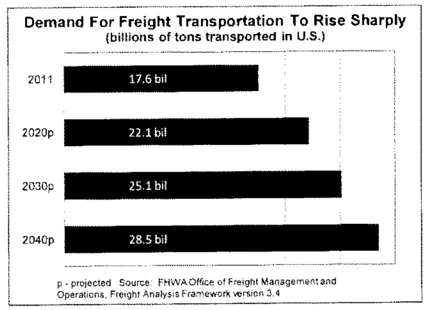
In 2011 (the most recent year for which data are available), U.S. railroads terminated nearly 341,000 carloads of ethanol, up from 47,000 carloads in 2002. In 2011, ethanol accounted for 1.2 percent of total rail carloads (up from 0.1 percent in 2002) and 1.7 percent of rail tonnage (up from 0.2 percent in 2002).

Each of the seven U.S. Class I railroads transports ethanol, with some serving several dozen plants. An estimated 15 to 20 percent of ethanol rail movements originate on non-Class I railroads — not surprising, given the rural nature of many short lines and much of America's ethanol production.

To be sure, the ethanol industry faces its own set of challenges, including the "blend wall" and the price of the corn that is the feedstock for most U.S. ethanol production. Ethanol producers should know that railroads will continue to work closely with them to help ensure America's ethanol transportation needs are met safely and efficiently.

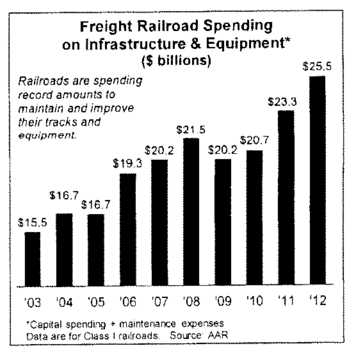
Railroad Capacity Issues

America's demand for safe, affordable freight transportation that promotes economic growth and enhances America's competitiveness in the global economy is sure to grow in the years ahead, for products relating to energy and otherwise. Recent forecasts reported by the Federal Highway Administration found that total U.S. freight shipments will rise from an estimated 17.6 billion tons in 2011 to 28.5 billion tons in 2040 — a 62 percent increase.



From time to time, interested parties question whether railroads will have the capacity to handle this increase in traffic. Along the same lines, sometimes there are questions concerning whether railroads can handle possible growth in crude oil volumes in the years ahead. We're confident that the answer to both questions is "yes."

As noted earlier, unlike trucks, barges, and airlines, America's freight railroads operate almost exclusively on infrastructure that they own, build, maintain, and pay for themselves. Because of the $550 billion — their own funds, not taxpayer funds — railroads have invested in locomotives, freight cars, tracks, bridges, tunnels and other infrastructure and equipment since 1980, the U.S. freight rail network is in better overall condition today than ever before and is the envy of freight rail systems worldwide. It's no surprise that The Economist magazine recently noted that the American freight rail system is "one of the unsung transport successes of the past 30 years" and is "universally recognized ...as the best in the world."[2]



In fact, in recent years, America's freight railroads have been reinvesting more private capital than ever before to renew, upgrade, and expand their infrastructure and

[2] The Economist, "High-speed Railroading: America's System of Rail Freight is the World's Best. High Speed Passenger Trains Could Ruin It," July 22, 2010.

equipment, including a record $25.5 billion in 2012 and a comparable amount in 2013. Rail spending this year is expected to be even higher. These investments enhance the capacity and capability of rail networks and the safety of rail networks.

Of course, markets change in every industry over time, and railroads are no different in having to be able to adapt to these changes. Indeed, for railroads, markets and related traffic patterns are continuously in flux. Making things more complicated for railroads is the fact that traffic volume for a particular commodity might be declining in one region at the same time that it's increasing for another commodity in a completely different region. (What's happening with crude oil and coal is a good recent example of this phenomenon.) Or, volume might be low for a particular commodity in one region one month, and much higher a few months later. (Recent experiences with grain, when rail traffic volumes went from record lows early in 2013 to above average in late 2013, is an example of this.)

The key point is that railroads have in place complex and remarkably effective operating plans that are able to incorporate the differing types of demand placed on various portions of a rail network, as well as the changes in that demand, at different points of time. These plans aren't perfect — day-to-day fluctuations in volume, weather, crew and equipment availability, for example, can have an enormous impact on the ability of a railroad to manage to the dictates of its operating plan, and even in the best operation, trains may be late (or early), customers may not release cars on time, bad weather may ensue, grade crossing accidents may happen, and delays may occur. Nevertheless, every day America's railroads do a remarkable job in meeting the needs of an extremely diverse set of shippers. On any given day, they are moving several hundred thousand carloads of freight. The vast majority of these shipments arrive in a timely manner, in good condition, and at rates that shippers elsewhere in the world would love to have.

In the case of crude oil specifically, the approximately 408,000 carloads originated by Class I railroads in 2013 represented about 1.4 percent of total rail carloads. Even if crude oil traffic doubled and railroads were hauling more than 20 percent of U.S. crude oil production, crude oil would still represent only around 3 percent of total carloads. This is less than the year-to-year variations railroads often see in traffic volumes.

That's not to minimize the importance of crude oil traffic, or imply that railroads don't incorporate the needs of their crude oil customers into their operating and infrastructure planning — railroads certainly do those things. It does mean, though, that while there may well be temporary rail capacity limitations in isolated areas where traffic volumes might be highly concentrated, it is unlikely that railroad line capacity will be a major factor in the ability of crude oil to move to market. Terminal capacity owned and developed by shippers and receivers may be another matter, but the solution to that potential problem is generally controlled by those who are most eager to develop crude production, and the tremendous growth in those terminals in recent years is a clear indication that the market is trying to take care of that issue. I noted earlier that railroads are advocating modifications to tank car designs to make tank cars carrying crude oil more robust. Depending on what regulatory steps are taken in this regard, it is possible that rail car availability might be an issue for crude oil, particularly during any transition period.

The bottom line, though, is that while railroad capacity may be a limited, location specific issue, it is almost certainly not a valid reason to believe that, in terms of crude oil production and distribution, growth will be seriously hampered.

As noted above, as America's economy grows in the years ahead, the need to move more people and goods will grow too. Railroads will continue to reinvest huge amounts back into their systems — they know that, if America's future transportation demand is to be met, rail capacity must be properly addressed. But if the United States is to have the socially optimal amount of rail capacity, policymakers must help. Perhaps the most important step policymakers can take in this regard is to retain the existing balanced system of railroad regulation. Today's balanced system protects rail customers against unreasonable railroad conduct while allowing railroads to largely decide for themselves how to manage their operations. Excessive regulation would prevent railroads from making the massive investments required to meet our nation's energy and other freight transportation needs.

Environmental Laws and Regulations

When railroads analyze the financial viability of potential infrastructure investments, one of the significant costs they must consider is associated with compliance with prevailing federal, state, and local environmental laws and regulations. While these laws are designed to further important societal objectives, they have at times been used to delay — and even force cancellation of — needed rail investments.

Under existing law, state and local regulations (other than local health and safety regulations) that unreasonably interfere with rail operations are preempted by federal regulations. These federal regulations protect the public interest while recognizing that railroads form an integrated, national network that requires a uniform basic set of rules to operate effectively.

Nevertheless, rail expansion projects — including projects that would enhance the ability of railroads to move energy products — often face vocal opposition from members of affected local communities or even larger, more sophisticated special interest groups from around the country. In many cases, railroads face a classic "not-in-my-backyard" problem, even for projects for which the benefits to a locality or region far outweigh the drawbacks. In the face of local opposition, railroads try to work with the local community to find a mutually satisfactory arrangement, and these efforts are usually successful. When agreement is not reached, however, projects can face lawsuits, seemingly interminable delays and sharply higher costs.

One of the many examples involves an intermodal terminal BNSF Railway has been trying to build for years near the ports of Long Beach and Los Angeles. This facility would eliminate millions of truck miles annually from local freeways in Southern California, while utilizing state-of-the-art environmentally friendly technology such as all-electric cranes, ultra-low emissions switching locomotives, and low-emission yard equipment. It would be one of the "greenest" such facilities in the world, but the project continues to face court actions and other protests. In addition, as mentioned earlier, rail-served coal export terminals in the Pacific Northwest and California are facing severe delays today due to permitting issues.

Policymakers can help improve the movement of freight by taking steps to shorten the time it takes for reviews of rail expansion projects in ways that do not adversely affect the quality of those reviews.

Conclusion

Freight that is related directly or indirectly to energy accounts for close to half of all rail traffic volume in the United States. Railroads are proud of the crucial role they play in energy-related transportation. They are working hard to ensure that adequate capacity exists to meet our future energy transportation needs, and they never stop seeking ways to make rail service safer. Railroads are committed to working with members of this committee, with their employers, with their customers, and with the communities they serve as we continue on the path toward greater energy security and energy independence.

Mr. WHITFIELD. Well, thank you, and thanks all of you for your testimony. We appreciate it very much. I recognize myself for questions, and then we will move forward as quickly as we can.

Mr. Black, I think you said that 99.998 percent of your products get to their destination safely, and, Mr. Hamberger, you said 99.98. Both of those are pretty good, but, Mr. Hamberger, you touched on this in your testimony, and there has been a lot of publicity recently about some accidents hauling oil out of the Bakken fields. And I was talking to some representatives of Burlington Northern Santa Fe yesterday, and it is my understanding they are moving out 700,000 barrels a day——

Mr. HAMBERGER. Yes, sir.

Mr. WHITFIELD [continuing]. Which is a lot of oil. And frequently we get confused about barrels versus car loads. How many barrels of oil is in a car load? Or maybe I should say gallons.

Mr. HAMBERGER. There are 30,000 gallons, which is 7,000 barrels, in a round figure——

Mr. WHITFIELD. OK.

Mr. HAMBERGER [continuing]. And 100 cars to a train.

Mr. WHITFIELD. OK.

Mr. HAMBERGER. So that would be——

Mr. WHITFIELD. OK.

Mr. HAMBERGER [continuing]. 70,000 barrels per train, a round——

Mr. WHITFIELD. And, you know, of course, we know about the Canadian accident, and there was some negligence involved there regarding braking systems, I believe, but——

Mr. HAMBERGER. Yes, sir.

Mr. WHITFIELD [continuing]. We have heard some stories that the oil coming out of the Bakken is more volatile. Are you aware of any evidence of that, or scientific analysis of that issue?

Mr. HAMBERGER. There is a lot of work going on in that area. The Pipeline and Hazardous Material Safety Administration launched what they termed back in August the Bakken blitz. I think they now call it Operation Classification. They have not yet issued their final report. What we have learned, just in discussions with them, is that there seems to be more natural gas liquids, ethane, butane, in the shale oil than some other oil. And that has led us to then call on the same Pipeline Hazardous Material Safety Administration, PMSA, to issue new tank car regulations which would be able to accommodate this more volatile oil.

Mr. WHITFIELD. And how are they coming along on those regulations? Are they moving quickly, or——

Mr. HAMBERGER. They are still contemplating. They published an advance notice of proposed rulemaking in September, and they have not yet come out with a notice of proposed rulemaking. But I am sure they are working on it.

Mr. WHITFIELD. Yes. OK.

Mr. HAMBERGER. And I should point out, not to throw them under the bus, but we actually petitioned PMSA in 2011. And when I say we, I mean the American Petroleum Institute, the American Chemistry Council, Association of American Railroads. Tank car manufacturers went in March of 2011 and asked them to promulgate a new tank car standard. When they did not do so, that same group of organizations got together and voluntarily adopted a new tank car standard, effective October 1, 2011, so that the tank cars being made since that time are dramatically an improvement over the current Federal regulatory standard. We think, given what we have just been talking about, that what was agreed to in 2011 can be made even more robust going forward.

Mr. WHITFIELD. So the industry is looking for some certainty?

Mr. HAMBERGER. Yes, sir.

Mr. WHITFIELD. OK.

Mr. HAMBERGER. Exactly.

Mr. WHITFIELD. Now, I think it is great that you all are doing this emergency response program out at Pueblo. How is that coming along?

Mr. HAMBERGER. We have a tank car emergency response training out there now, but it does not focus on crude oil. We are looking to get 20 tank cars out there, to have them arrayed as if there had been an accident, to have them set up so that they will, in fact, be on fire, have foam, have emergency response uniforms for people to work. We are hoping to provide at least 1,500 emergency responders the opportunity to go through that program starting July 1, and that would be on top of the 2,000 we already train out there. And that would be an ongoing program into 2015 and beyond.

Mr. WHITFIELD. OK. Thank you. At this time, Mr. McNerney, you are recognized for 5 minutes.

Mr. MCNERNEY. Thank you. I ask unanimous consent to include a letter from Mr. Loebsack to the committee to be included.

Mr. WHITFIELD. Without objection.

[The information follows:]

Congressman Dave Loebsack (IA-02)
Statement for the record
Benefits of and Challenges to Energy Access in the 21st Century: Fuel Supply and Infrastructure
March 6, 2014

Chairman Upton and Ranking Member Waxman, thank you for the opportunity to submit a statement for today's hearing on the "Benefits of and Challenges to Energy Access in the 21st Century: Fuel Supply and Infrastructure."

This winter, states across the Midwest have seen record high propane prices that have wreaked havoc on Iowan's pocketbooks and quality of life. While propane prices typically average \$1 to \$2 per gallon, Iowans have seen this skyrocket to over \$4 per gallon, and even top \$5 per gallon in some instances. This is unsustainable and unacceptable for Iowa families. The doubling and tripling of propane prices is causing thousands of Iowans to struggle to make ends meet and to keep their heat on during the extreme cold temperatures experienced this winter. In Iowa, propane is a critical fuel that heats 13 percent of Iowa homes in addition to barns that keep thousands of livestock alive during the winter months.

Throughout the propane crises in the Midwest, Governors, the U.S. Department of Transportation (U.S. DOT), Department of Energy (DOE), and the Federal Energy Regulatory Commission (FERC) have taken important steps to expedite the shipments of propane to the Midwest. These steps were critical to providing relief. However, it is clear from the hodgepodge of steps taken to address the problem that no comprehensive plan exists for all parties to coordinate and to ensure that a fuel supply disaster that threatens the livelihoods of thousands of Iowans never occurs again.

From the National Propane Gas Association's testimony, there is extreme cause for concern over pipeline infrastructure flows, rail capacity, and exports causing supply restrictions that must be addressed. Consumers who rely on fuels like propane to provide a basic need like heating their homes should not be held victim to the profits of the oil and gas industry. This winter has additionally brought together a storm of crop drying demand and extremely cold temperatures that has contributed to diminished propane supplies. However, with the supply constraints and exports facing the industry, there is no reason a similar fuel supply disaster could not happen again. I am asking the House Energy and Commerce Committee to coordinate the development of an emergency response plan across all relevant federal agencies and state actors including U.S. DOT, FERC, DOE, the Federal Emergency Management Agency, Department of Health and Human Services, and governors to be able to quickly respond to home heating fuel shortage disasters similar to what the Midwest is experiencing this winter.

Thank you again for allowing me to submit my statement today, and I look forward to working with the Committee to address this critically important issue.

Mr. MCNERNEY. Well, I want to thank the witnesses. I think it was a good set of testimony. Well, one side of the aisle wants to move forward with production, produce, produce, produce, and the other side says, well, you know, what about safety, what about the environment? So it is important to have a balance between these two, and I think that is what we ought to be aiming for.

My first question goes to Mr. Logan. I appreciate your comments about flaring. The question I have is kind of political. How much resistance do you think industry would put up to regulating down the flaring levels?

Mr. LOGAN. Well, I think if you asked me the question a year ago, I would have said a whole lot. I think we have seen so much negative attention on the flaring problem over the last year, and also the fact that, you know, the data show that the problem does continue to get worse, so I think there is a growing recognition from industry, as well as from other stakeholders, that voluntary action to date has not gotten the job done.

Well, there are companies that are taking kind of leadership steps to reduce their own flaring, and now see that the actions of some of their peers who aren't doing the right thing sort of drags the whole industry down.

Mr. MCNERNEY. So companies are saying, hey, it is probably in our interest to move forward with a reduction of flaring?

Mr. LOGAN. That is right. I think the question is how far, and kind of what the levers——

Mr. MCNERNEY. Thank you.

Mr. LOGAN [continuing]. To make that happen are.

Mr. MCNERNEY. Mr. Whittington, I appreciate your comments about the reduction in obstacles to the Federal hours of service regulations, and I look forward to working with you on that. I don't really have a question, but I appreciate your comments on that.

Mr. WHITTINGTON. Be delighted to work with you.

Mr. MCNERNEY. OK. Mr. Obeiter, 3-year payback is possible on reducing fugitive emissions, equipment to reduce fugitive emissions?

Mr. OBEITER. Yes. There have been a number of case studies through the EPA Natural Gas Star program, as well as other programs, that have demonstrated that the vast majority of emissions control technologies pay for themselves in 3 years or less.

Mr. MCNERNEY. So how serious is the problem of methane leaks from our natural gas infrastructure?

Mr. OBEITER. It is impossible to say with precision, but we know that it is a significant problem. We know that recent numbers from the EPA inventory, and a survey by industry of fugitive methane emissions likely understates the case. You know, methane is the second most important greenhouse gas after carbon——

Mr. MCNERNEY. So is there good technology out there in existence to help us detect leakage in pipelines and in fracking wells?

Mr. OBEITER. There is. There is technology that can detect leaks, and there is technology to go in and fix those leaks wherever they may be.

Mr. MCNERNEY. And is that being implemented, or is there resistance to implementing that?

Mr. OBEITER. It is being implemented on a voluntary basis in some places, but there has been some resistance simply because, in a lot of cases, a 3-year payback, which sounds great to me, does not compare favorably with a lot of the investments made by these natural gas companies.

Mr. MCNERNEY. And one last question for Mr. Hamberger. How compliant are your members to the voluntary actions that you discussed? I mean, you must have a variety of responses to those——

Mr. HAMBERGER. Well, all class one railroads have subscribed to it, and many of our short line members are as well.

Mr. MCNERNEY. So when you say subscribe to it, you mean they are——

Mr. HAMBERGER. They have committed publicly, signed by the CEO or the Chief Operating Officer on a piece of paper with the Secretary of Transportation that they are committed to adhering to these voluntary items. The administrator of the Federal Railroad Administration has testified that he will direct his inspectors, even though they are voluntary, to treat them as though they were regulatory mandates, and would make public any, you know, this is a commitment that we made in 35 days.

Mr. MCNERNEY. Well, I want to wrap so others can question, but the voluntary measures you identified sounded pretty good——

Mr. HAMBERGER. Thank you, sir.

Mr. MCNERNEY [continuing]. So let us see those implemented.

Mr. HAMBERGER. Yes, sir.

Mr. WHITFIELD. Thank you. At this time recognize the gentleman from Louisiana, Mr. Scalise, for 5 minutes.

Mr. SCALISE. Want to thank the chairman for having this hearing, and want to thank all of our panelists for the information you have been providing.

Want to first ask you, Mr. Black, in your testimony, and in, you know, you all are heavily involved in all the pipeline infrastructure throughout our country. There is a heated debate in this town about the Keystone XL pipeline. I know you referenced it in your testimony. Legislation has been passed in the House to approve the Keystone XL pipeline, very large bipartisan majorities. Obviously, right now, that rests with the President. The President likes talking about using a pen to change laws, especially as it relates to his healthcare law, but one thing the President could do today is actually use a pen to approve the Keystone XL pipeline, and create thousands of good jobs, increased energy security, and a trading partner with Canada. And, again, you mentioned the pipeline infrastructure between the United States and Canada in your testimony.

There has been some debate about the types of job creation that would come with Keystone XL. And there is some very good reports out there, talking about not only billions of dollars of private investment that would come in, but tens of thousands, over 20,000 jobs that would be created. The President often trivializes that, and tries to diminish the job impact. Can you talk to the jobs that would be created, and the energy security that would be created, by approving and developing that pipeline relationship with Canada for Keystone XL?

Mr. BLACK. Sure. Thank you, Congressman. The State Department's final environmental impact statement shows that more than 20,000 jobs would be created Keystone XL. Those are real, good paying jobs. And you are right, the President has the opportunity to sign that permit. And while Congress has acted, and we support the interest of Congress in Keystone XL, the quickest way to do this is just for the State Department to grant a presidential permit. Tomorrow is the final day of comments on the national interest determination, and we hope that soon after that there will be a recognition that this has support not just from a majority of the House and of the Senate, but also of the American people of all parties.

Mr. SCALISE. Well, let me ask you about the jobs, because we still have a very struggling economy. I think if you look at a lot of the policies coming out of this administration, many of those policies, in fact, are the reason that you have such a sluggish economy, when you talk to families who are struggling, people that just got reduced to 28 hours that used to be working 40 hours because of the President's laws and policies. But let us talk about the Keystone jobs, because, again, the President does diminish this. I don't know if you all have done your own study, I have seen studies. What is the impact that you have seen on what kind of jobs would be created in America?

Mr. BLACK. Well, I would refer you to the tremendous support that the project has from the labor community. And when I have been in Nebraska, I have found that the union jobs there that will be supported are tremendous. They are some of the best advocates for this project. There will be manufacturing jobs making pipe, making steel. There are also ancillary jobs in finance and in insurance. A lot of these jobs are going to be outside of the pipeline route. There has been one study that 80 percent of the jobs will be throughout the nation. So it has many positive benefits on——

Mr. SCALISE. Any ideas on numbers, on how many jobs you are talking about?

Mr. BLACK. I don't have those in front of me. I will be happy——

Mr. SCALISE. Because I have seen upwards of 20,000 jobs. And, again, the President trivializes this, and acts as if, you know, those aren't good jobs anyway. You know, maybe we ought to send a copy of this testimony to the President, and maybe he reconsiders a decision. I don't know if he is out of ink on his pen. I will lend him my pen to sign the Keystone pipeline if he wants to. But, you know, it is just something that people are frustrated with. When they are struggling, they are looking at an economy that is struggling, they want to work. They just want to go back to work.

And you have got 20,000 jobs or more that, as you say, are good high paying jobs that would be helping not only create energy security for this country, but also put food on the tables for those families, and the President continues to say no, and then try to trivialize what, to them, would be an important improvement in their life, and their quality of life. So I just hope, you know, we continue this conversation. We are going to continue pushing it, but I appreciate the testimony you gave on it, because——

Mr. BLACK. Be happy to get you some information about——

Mr. SCALISE [continuing]. To underscore. Anything else you can get us, please let us know, and we will even pass it on to the White House, and maybe they will read it.

Mr. Hamberger, I want to ask you about some of the comments you made about the enormous growth in crude oil——

Mr. HAMBERGER. Yes, sir.

Mr. SCALISE [continuing]. Specifically that has been moved through rail through 2008. Can you expand on that and tell us what you are seeing?

Mr. HAMBERGER. Yes, sir. In 2008, 9,500 car loads. In 2013, over 400,000 car loads. To put that in perspective, that is only about 1½ percent. We move about 30 million car loads a year. So while that is incredibly rapid growth, it is something that we think we can accommodate. As I mentioned, our coal franchise is down 23 percent from the height in 2008. But it is traffic patterns in perhaps new areas, and so that is why this year we are investing $26 billion in capex and maintenance to try to expand the infrastructure, and be able to handle it. We expect it will continue to grow at those rates, and we will exceed another couple hundred thousand barrels, 10 car loads, this year. I am being given the——

Mr. SCALISE. Appreciate your answers, and the job creation that you are bringing along with that investment.

Mr. HAMBERGER. Yes.

Mr. SCALISE. Yield back the balance of my time. Thank you.

Mr. WHITFIELD. OK. Ms. Christensen, we will try to get you——

Ms. CHRISTENSEN. Right. I will try to——

Mr. WHITFIELD [continuing]. Before we go out.

Ms. CHRISTENSEN [continuing]. Be quick. Thank you.

Mr. WHITFIELD. You are recognized for 5——

Ms. CHRISTENSEN. I appreciate that, Mr. Chairman, and thank you for this hearing. You know, the testimony that we have received this morning is of particular interest to me, as our utility in the U.S. Virgin Islands undergoes a major transition from diesel as our sole generation source to propane, and then eventually to natural gas, which is projected to lower our rates by at least 30 percent. So we were particularly concerned when we saw the dramatic shifts in the propane market, as we wondered how that would affect our future.

So, Mr. Roldan, while I do understand that this is part of your share, due to rapid abundance, and then a series of demands and pressures, including the polar vortex, still, as we go forward, this is something we have to consider. Could you share for the record what your perspectives are, and what needs to happen to ensure price stability in the propane market, should this perfect storm happen again?

Mr. ROLDAN. Yes. Thank you for the question. It is a very good question, actually. Because we feel under pressure as transportation and storage assets are being taken out of service, the best thing that we could do, as an industry, is build year-round demand. There is no greater incentive for an expanding infrastructure than if you were to take a season industry and build year-round demand, but that is something that takes place over time.

We think that the system could use a big dose of transparency, OK? So we are studying this right now. We have formed an industry task force, and, in a very short period of time, we will come back with concrete policies and recommendations, but we think that the system could use a whole lot more transparency. And let me tell you what I mean by that. We hit a period in the Midwest in late January where essentially, the wholesale price tripled.

Now, to be honest with you, I don't know what happened in that 10 day period, and I can't explain it. I have been associated with this industry for 20 years, and I can't explain it. And so we have joined with Senator Charles Grassley, and other members of Congress, to ask the Federal Trade Commission to look into the transactions that led to that. Because the six million households that depend on our product to heat their homes——

Ms. CHRISTENSEN. Um-hum.

Mr. ROLDAN [continuing]. Are asking us to prove that things are on the up and up. And not only do our customers want to know, but our retail marketers want to know that our markets are performing properly. I have a whole series of recommendations on new data sets that would help our industry, and I will give you a quick example.

Ms. CHRISTENSEN. OK.

Mr. ROLDAN. We believe that markets function more efficiently when transparency is there. When you lack transparency, they perform less efficiently. And, just to give you an example, the EIA does a wonderful job reporting inventory data, OK? But if we are exporting one out of every five gallons, and major foreign purchasers are signing long term contracts, if we don't know what percentage of our inventories at Mont Belvieu and Conway are committed by contract, then we don't know what our available inventories are in this country. That is the type of transparency policies we are going to promote.

Ms. CHRISTENSEN. Thank you. Let me try to get in another question. The testimony has focused primarily today on how we can improve, yes, oil and gas transportation infrastructure. But any meaningful discussion of investing in new energy infrastructure has to consider how the energy choices we are making today will have long term impacts for our climate.

Mr. Obeiter, in your written testimony you state that the infrastructure choices we make today will reverberate for the next 40 to 50 years. Ignoring the climate when making these decisions risks stranding valuable assets. Can you expand what you mean? How can ignoring the risks posed by climate change pose an economic risk to a company?

Mr. OBEITER. Sure, thank you for the question. If you believe, as I do, that we need to make significant reductions in greenhouse gas emissions in order to stabilize the climate, and avoid the worst impacts of climate change, then we need to be thinking long term when making energy infrastructure decisions. The infrastructure is very long lived, and we risk either stranding these assets, as we move away from high carbon fuels to low carbon, or zero carbon, electricity, or we risk locking in, essentially, catastrophic climate change, one or the other. And so this is why I believe it is important to think extremely long term when thinking about the energy infrastructure decisions we are making today.

Ms. CHRISTENSEN. And what measures are some companies taking, or are they taking, to incorporate climate change into their investment decisions?

Mr. OBEITER. A number of companies are incorporating a shadow price of carbon into their internal decision-making processes. These are not just the companies you would think of, but they include massive multi-nationals, like Walmart, and even Exxon-Mobil, which has disclosed that it is incorporating a $60 price per ton on carbon into its internal decision-making.

Ms. CHRISTENSEN. Thank you, Mr. Chairman.

Mr. WHITFIELD. Thank you. I want to apologize to you all, we have a series of votes on the floor. We were trying to get through as quickly as possible. I think Mr. Hamberger has a previous appointment. I think Mr. Sieminski does as well. But for the others, I know some of the members have some additional questions, and if you all would have time, you know, we have two of the best restaurants in America over at the Longworth cafeteria and Rayburn cafeteria, so if you want to go over there and have something, and we will be back here within 1 hour. So thank you, and I do apologize, but we will reconvene in 1 hour. Thank you.

[Whereupon, at 10:12 a.m., the subcommittee recessed, to reconvene at 11:14 a.m. the same day.]

Mr. WHITFIELD. Once again, I will apologize to you all for the delay. And this time I am going to recognize the gentleman from West Virginia, Mr. McKinley, for 5 minutes of questions and/or comments. He ran all the way over here, but he is so physically fit, he won't have to have any time to recuperate at all.

Mr. MCKINLEY. Thank you, Mr. Chairman, and thank you for your presentation. There were a couple questions that I wanted to ask before we broke earlier on the oil pipeline, it was 99.9998 percent efficiency, railroads were 99.98. But I heard some of the discussion earlier about the fugitive gas emissions, and it looks like the amount of gas that we are transmitting, maybe we are losing, is it right, maybe 1.4 percent, something like that, or is it better?

Mr. OBEITER. The EPA inventory, the most recent version, has approximately 1.4 percent leakage rate. But more recent studies that take direct measurement suggest that it could be much, much higher than that.

Mr. MCKINLEY. How about someone else in the industry that might be able to comment?

Mr. SANTA. Mr. Obeiter is correct that the latest EPA inventory number is 1.4 percent. There are a variety of other studies going on. As a matter of fact, as Mr. Obeiter pointed out in his written statement, there is a lot of work going on involving not only EPA, but industry, environmental groups, and academia looking at this to get a better handle on it. And I think, really, we are best to await the results of that to form the basis——

Mr. MCKINLEY. OK.

Mr. SANTA [continuing]. Of making policy.

Mr. MCKINLEY. And I just need to have a little bit more confirmation, because sometimes we chase the wrong rabbit sometimes in trying to improve on efficiency of 99.98, or 99.9998. How much more money should we invest to try to perfect that?

We have heard the comments earlier about climate change. We have heard in previous testimony and other hearings about the dangers of climate change, and use of fossil fuels, be they coal, oil, or gas, that it is causing premature deaths, it is causing asthma, sicknesses. Do you agree that the product that you are shipping is causing climate change problems around the world? Let us start with you.

Mr. SANTA. I will take the first stab at that answer, and, yes, the point that I would make is that, you know, we have seen reductions in U.S. greenhouse gas emissions, and one of the factors that has been cited as a contributor to that is the increase utilization of natural gas to generate electricity in displacing other more carbon intensive fuels. Clearly there are GHG emissions associated with natural gas, but cleaner than other fuels, and also I think, you know, we can focus on ways to reduce those emissions. But I think overall the net contribution, both to reduce GHG emissions, and overall cleaner air from natural gas, has been a real positive for the United States.

Mr. MCKINLEY. Look, I am one of the two engineers here in Washington. I acknowledge that there is climate change as a result of all this, but I am trying to understand how much of it is man-made, and how much of it is natural and cyclical, and whether or not we are pursuing an agenda that is more ideologically intended, rather than consequential.

So I am really interested in where we go with this, because we know that burning the tropical rain forest is far more dangerous and threatening to the ecology and the environment around the world than is coal fired or gas fired power plants in America. But yet we seem to be bent on this war on coal, and war on fossil fuels, and you all are participating in it by transporting our gas, oil, and then railroads with coal. I am curious to see if you feel that that is the right thing to do. Is it indeed contributing to the environmental problems with climate change? You have answered that. Mr. Roldan, did you have a comment?

Mr. ROLDAN. Yes. If I could add the voice of propane to that, because people talk a lot about natural gas.

Mr. MCKINLEY. Yes.

Mr. ROLDAN. What is often lost is the fact that propane is used in the very same applications as natural gas. We reduce greenhouse gas emissions anywhere from 15 to 18 percent, to as much as 50 percent in some applications. So we actually think that we are part of the solution. And I would also draw your attention to comparisons between reductions in greenhouse emissions in Europe, where they have an economy-wide cap and trade program, and greenhouse gas emissions reductions in the United States, and I think the record in the United States is considerably better than Europe.

Mr. MCKINLEY. OK. I am afraid we are running out of time here, so I apologize for the shortness of time, but thank you all for being here.

Mr. WHITFIELD. At this time recognize the gentleman from Virginia, Mr. Griffith, for 5 minutes.

Mr. GRIFFITH. Thank you so much. Mr. Santa, I am going to continue with you. I notice that, in your testimony, you mentioned that the INGAA will be releasing an updated report on the need for new natural gas pipeline infrastructure over the next 15 years. You also state the report will show the need for natural gas pipeline infrastructure will be significantly higher than the 2011 report found. What are the reasons for demand to be significantly higher than in the previous estimates?

Mr. SANTA. Thank you for the question, Mr. Griffith. Our report is going to be released on March 17. What we have noted, compared to when we did the report back in 2011, is the shale revolution, the fact that it is of a greater magnitude than we appreciated then, not only with respect to natural gas, but also gas liquids and oil production, and that that is driving the need for more pipeline infrastructure.

Mr. GRIFFITH. I appreciate that. And you state your support for H.R. 1900 in your testimony. Can you please clarify why there is a need to address delays from agencies other than FERC that issue permits necessary to construct natural gas pipelines?

Mr. SANTA. Yes. We do support H.R. 1900, and we think that the issue to be addressed here, and INGAA, and The INGAA Foundation have documented this, that the duration of delays for the variety of other permits that a pipeline applicant must get before it can proceed with construction has, in fact, gotten longer, and that this can be very costly, both for the pipeline sponsor, but for the market. Let me illustrate that. In many instances, when you are constructing in an environmentally sensitive area, there is a limited construction window during the year. So if you are delayed by two months, if you miss that construction window, you could be delayed by a year, in terms of your ability to build that infrastructure. So we feel that the discipline and accountability that H.R. 1900 would bring to the process would be a positive.

Mr. GRIFFITH. And it seems to me that, when you have these issues of delays from agencies in getting new pipeline laid and out there, that that makes it that much more difficult to get the natural gas to the places that it is needed and wanted, and that perhaps the administration has been shortsighted in its war on coal by attacking our coal resources, and saying, well, we are going to use natural gas, at least as a transition, and that natural gas is the way to go, and then start holding up all kinds of other things, and making it difficult for natural gas to get to the market. Wouldn't you agree with that, yes or no?

Mr. SANTA. I would agree that there is a cost associated with delays in getting natural gas to the market, yes, sir.

Mr. GRIFFITH. One of my arguments, and many others on this committee feel this way, is that the EPA, on its regulations that are basically attempting to put coal out of business, particularly when it comes to electric power generation, that the EPA is moving faster than the science. Other testimony comes in and says maybe 10 years, maybe 7, but probably 10 years before the technology is available to meet the regulations that are out there now.

And yet we find in the testimony today that, and I quote from page two of Mr. Obeiter's testimony, that, "although natural gas emits only 50 to 60 percent as much CO2 as coal when burned for electricity generation, fugitive methane emissions throughout the natural gas life cycle undermine the climate advantage of switching from coal to gas."

Now, I understand that when we get those kinks worked out, as Mr. Logan and Mr. Obeiter have mentioned today, and you don't have methane flaring, and you don't have as many leaks in the pipes, and you are not admitting it, natural gas may be better, but, again, it appears that our administration currently in power in DC over these agencies has gotten the cart in front of the horse, and that we need to continue to use coal for the foreseeable future, because that is actually cleaner for the environment, until we figure out how we can get all those pipe leaks taken care of, and we don't have the flaring going on. So I think the testimony today has been very interesting in that regard.

Mr. Whittington, on the propane side, you indicated that it is generally 50 to 100 miles for transport——

Mr. WHITTINGTON. Yes, sir.

Mr. GRIFFITH [continuing]. But your testimony also indicates that maybe as much as 800 this last year. What was the reasoning for that?

Mr. WHITTINGTON. The supply was not at the locations that we generally haul from because of the problems of moving the product into the caverns. And then what is happening in the fracking thing, when you look at all the fracking up in Pennsylvania, Ohio, West Virginia, in that area, they were planning on having product coming to the marketplace a lot quicker, and it didn't. And, therefore, the pipeline that had been feeding that area for so many years wasn't anticipating the need that they needed to have there, so we were forced in shortages.

One example I can tell you, we were at Catlettsburg, which is pretty near your area, 10:30 one night to load, and the company we are hauling for was put on allocation. We were going to Winchester, Kentucky. The next phone call, that truck leaves there empty, goes to Hattiesburg, Mississippi, to come to Winchester, Kentucky, because that is the only place we could get the guy propane. And he had homeowners, and people that——

Mr. GRIFFITH. I am sure.

Mr. WHITTINGTON [continuing]. Hog houses, chicken houses that were needing that kind of thing, but we had to go to where the supply was. But it was interrupted in so many places because we were counting on a supply, and it didn't happen.

Mr. GRIFFITH. All right. Appreciate it very much. My time is up. I yield back, Mr. Chairman.

Mr. WHITFIELD. At this time recognize the gentleman from New York, Mr. Tonko, 5 minutes.

Mr. TONKO. Thank you, Mr. Chair.

Mr. Roldan, how much time, and what resources, are required to reverse the flow of propane in a pipeline?

Mr. ROLDAN. Well, I will give you an example. In fact, I am probably going to have to get back to you on that question. The best example I have right now is that the Texas eastern pipeline, that flows from the Gulf Coast up into the Midwest, and serves the Northeastern United States, recently reversed part of that line, a 16-inch line, to flow southward, rather than northward. And I will get you a specific answer to that, how long it took to do that, but

I want to make a quick point here, because this affected the Northeast, and your constituents. When you reverse a line, imagine that there are products, it is a mixed batch line, that flow in the 16-inch line, and they both go northward. If you reverse the 16-inch line to go south, all of those products that are shipped on that 16-inch line cause congestion on the 20-inch line, and that is exactly what we saw happening this year.

Mr. TONKO. Um-hum. Thank you, and I appreciate anything you can forward——

Mr. ROLDAN. Certainly.

Mr. TONKO [continuing]. To the subcommittee concerning that.

[The information follows:]

NPGA
NATIONAL PROPANE GAS ASSOCIATION

March 18, 2014

The Honorable Ed Whitfield
Chairman, Subcommittee on Energy and Power
House Energy and Commerce Committee
U.S. House of Representatives
Washington, D.C. 20515

The Honorable Bobby Rush
Ranking Member, Subcommittee on Energy and Power
House Energy and Commerce Committee
U.S. House of Representatives
Washington, D.C. 20515

The Honorable Paul Tonko
Subcommittee on Energy and Power
House Energy and Commerce Committee
U.S. House of Representatives
Washington, D.C. 20515

Chairman Whitfield, Ranking Member Rush, and Congressman Tonko:

On March 6, 2014, the Energy and Power Subcommittee held a hearing titled, "Benefits of and Challenges to Energy Access in the 21st Century: Fuel Supply and Infrastructure," during which I testified on behalf of the 3,000 members of the National Propane Gas Association (NPGA). I would like to provide the Subcommittee with a more complete answer to one of the questions posed by Congressman Tonko.

Congressman Tonko, you asked, "How much time and what resources are required to reverse the flow of propane in a pipeline?" Please find my response below.

There are several different types of propane pipeline reversals. Depending on the specific circumstances of the pipeline, a pipeline flow reversal can take from two weeks to three years or more to plan and implement. We have described the different types of pipeline reversals below:

1) **Reversal of flow on a tariffed bidirectional pipeline**

Certain pipelines, including the Phillips66 Borger-Denver line, parts of the Oneok system, and parts of the MAPL system, are designed to allow flow to be reversed on a seasonal or short-term basis to match changes in demand.

These pipelines have FERC tariffs that specify the terms and conditions of the pipeline reversal. The reversal itself is typically planned on an annual basis, hence providing significant notice to shippers at both ends of the system. Implementation of the reversal depends on the length of the pipeline, since the last shipment going in one direction must clear the pipeline before the first shipment going the other way is put into the pipeline. This can take two to three weeks from the time that shippers stop putting product into the pipeline at one end until products from the other end of the pipeline can reach the delivery point.

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In addition, it is relatively easy to permanently reverse a tariffed bi-directional pipeline by canceling the tariff serviced for flows in one direction. FERC rules based on the Interstate Commerce Act allow pipelines to cancel a pipeline tariff for a specific service at any time, and without effective notice.

2) Reversal of flow on an nontariffed bi-directional pipeline

During the recent supply crisis, Oneok Partners requested FERC tariff approval to reverse North Line 5 of the Oneok system running from Kansas to Oklahoma for South-North service, allowing the shipment of propane from its Medford, OK fractionation hub to Bushton, KS, adjacent to the Conway hub. This section of the ONEOK system was originally designed to be bi-directional, but the pipeline had not filed tariffs for bi-directional flow by FERC and thus did not have approved FERC tariffs for bidirectional flow. The timeframe for a reversal of this pipeline or similar pipeline segment is similar to the time frame for the reversal of a tariffed bi-directional pipeline, with the additional time necessary to file for and receive FERC approval of the tariffs specifying the terms and conditions for the reversed flow services. Depending on the priority placed on the reversal by the pipeline company and by FERC, this can add a few days to a couple of months to the reversal project.

3) Reversal of flow on a non-bi-directional pipeline

Most pipelines are built to flow only in one direction. Reversing the flow on these pipelines can require significant investments to modify the pipeline compressor stations, valves, receipt and delivery points, and other infrastructure to enable the pipeline to flow in the opposite direction. In addition, these changes likely require tariff approval from FERC, as well as negotiations with new shippers that would be served by the reversal. As a result, this type of reversal can take six months to two years to accomplish.

4) Repurposing an existing propane pipeline to provide non-propane services

There have also been two major pipeline projects that reversed the flow of the pipeline and converted the pipeline to ship other products instead of propane. These projects include:

- The Kinder Morgan Cochin pipeline project is in the process of converting an existing propane pipeline from Alberta, Canada, into the Midwest to a diluent pipeline transporting natural gasoline and diluents from the Midwest to the Alberta oil sands.
- The Enterprise ATEX project took a section of pipe from the TEPPCO pipeline flowing from the Gulf Coast to the Northeast out of service and repurposed the pipe to move ethane from the Marcellus Basin in Pennsylvania to the Gulf Coast

This type of project requires significant changes to the physical structure of the pipeline, as well as regulatory approval for the cessation of the original services and approval of the new services, which in all can take two to three years (or longer) from the time that the project is announced until project completion.

The Cochin pipeline reversal, which will be completed in June/July of 2014, will have taken about two years from the notice of open season offering services on the reversed pipeline, which occurred on April 23, 2012, until commissioning of the project. This project required multiple regulatory approvals. Kinder Morgan filed the request for approval with FERC on August 9, 2012, and received approval on October 22, 2012, less than 12 weeks after the initial filing date. The project also required approval from the Canadian National Energy Board (NEB), which was requested on August 12, 2012, and received on June 13, 2013. In addition, because the repurposing resulted in the export of crude oil (by definition, diluent or field condensate is considered a form of crude), Kinder Morgan required a Department of State Presidential Permit, which was applied for on August 7, 2012, and granted on November 19, 2013.

The ATEX Pipeline open commitment period was initiated on October 11, 2011, and brought into service in December of 2013, slightly more than two years after the project was initiated. It is worth noting that as part of the review of the ATEX pipeline application by Enterprise, FERC determined that it does not have jurisdiction over the abandonment of service by oil pipelines:

> The Commission lacks jurisdiction over the abandonment of service by oil pipelines. As such, the Commission has no jurisdiction to require an oil pipeline to continue to provide a service that it wishes to cancel in its entirety. In its proposed tariff filing, Enterprise TEPPCO makes it clear two distinct services—jet fuel and distillates—are to be entirely discontinued for interstate mainline service. The Commission determines this to be a complete abandonment of service, and as such, the Commission does not have jurisdiction to prevent such an action by Enterprise TEPPCO.[1]

It is my hope that these details on pipeline reversals, and the timelines to do so, have been helpful. Thank you again for the opportunity to testify before the Subcommittee and please let us know if we can ever be helpful in the future.

Sincerely,

Rick Roldan

Richard Roldan
President & Chief Executive Officer
National Propane Gas Association

[1] 143 FERC ¶ 61,191, Docket No. IS13-265-000, page 7, paragraph 20. May 31, 2013.

Mr. TONKO. Are the decisions about what product is in the pipeline, or the product's direction of flow, subject to input or review by either State or Federal agencies?

Mr. ROLDAN. Yes, it is subject to FERC review. And I realize that there are different statutes that govern natural gas transportation and petroleum products transportation, but it is our view that there are certain standards on the natural gas side where, if you are going to discontinue a service, the commission takes into consideration the impact it is going to have on end users. That doesn't really happen on the petroleum products side, and we think that that should happen. Somewhere in that process we have to take into consideration the impact that those business decisions are going to have on the consumer.

Mr. TONKO. Thank you. And does permitting for export facilities take into account the potential of United States shortages of propane that could result from the increased export——

Mr. ROLDAN. It does not. That is sort of a big disconnect between, again, natural gas and propane. If you export natural gas, you factor into that equation the effect on U.S. consumers, and whether it is in the best interest of the United States. No such consideration is given for propane exports.

Now, I will tell you one quick point. We know that global demand is driving production to record levels. We also know that those very same global markets are forcing American consumers to compete with foreign buyers. Now, we think there is a continuum out there somewhere between completely unfettered exports and a near export ban that similarly applies to crude oil today. We think that somewhere between those goalposts there are some reasonable policy options that will allow us to continue to foster increased production, but at the same time allow us to serve our customers reliability. And those are the policy options that we are looking for now.

Mr. TONKO. OK. In reference to the hours of service waivers that have been granted——

Mr. ROLDAN. Certainly.

Mr. TONKO [continuing]. Do these waivers apply to any truck transport of propane, or only to delivery of propane for heating to shortage areas?

Mr. ROLDAN. Any truck.

Mr. TONKO. Any truck? And could this also apply to deliveries to refineries for feed stock propane, or to propane delivered for export?

Mr. ROLDAN. I believe the answer to that question is yes, but I would like to confirm that for you.

Mr. TONKO. Well, I would point out that, while these waivers are necessary to deal with a serious supply problem, they increase transportation risks. So not only are our citizens accepting environmental costs and risks associated with drilling, processing, and transport of these fuels, the risk we have just increased with these waivers. As an added cost, they have fuel shortage and high prices.

If this is what the market has provided, it is unacceptable. We need a more strategic energy plan here that emphasizes something more than just getting the best price for large fossil fuel supplies in whatever market will provide it. And I think this propane situation illustrates clearly that increased domestic productions to not necessarily result in domestic energy security, and is something that I think we need to work on as a committee.

Mr. ROLDAN. I think you are right, and if you want to look at the numbers, you will find that year over year the increase in propane production here was about 1.5 billion gallons. The increase in propane exports was two billion gallons. So this is the first year, the first season, where propane export volumes exceeded new production coming on line from shale development. And that is a bit troubling to us, and we are looking at policy options right now to propose that might alleviate that situation.

Mr. TONKO. I thank you. And, Mr. Chair, I yield back.

Mr. WHITFIELD. Mr. Whittington, did you want to make a comment? You seemed to——

Mr. WHITTINGTON. We could haul to the retailers that were moving that product and be exempt from the hours of service. Well, if you are going to a refinery, or you are going to an export terminal, we did not have an exemption from the hours of service on those trucks.

Mr. WHITFIELD. All right. Thanks. Mr. Shimkus, you are recognized for 5 minutes.

Mr. SHIMKUS. Thank you. And, I am sorry, I am bouncing back, and so some of this may have been asked over this discussion, but just to the propane issue and transportation, I know that in our area we had truckers who were usually doing a short haul of 100, 150 miles driving, I am from southern Illinois, going to North Carolina. So not only do you lose the multiple runs, but, obviously, then you have this address. I am not a great fan of my Governor, but he did well in this process, and I think it was testified throughout that people were really trying to respond.

And before that, it is good to see Bobby back. He has been absent for a while, and we are glad to have him back here. And Andy Black, you know, what goes on in the committee stays in the committee, so we won't harass you too much, but it is always good to see you. And he helped me cut my teeth on the committee, so I appreciate seeing you.

No one disagrees, I would assume, and we are going to find out, because I am going to ask it, that liquid commodity products, the cheapest, safest way to haul a liquid commodity product is a pipeline. Does everyone agree with that? So everyone is saying yes, except for Mr. Roldan?

Mr. ROLDAN. Yes. I think the difference is, if you compare rail rates to pipeline rates, rail rates tend to be considerably higher, except when it comes to propane.

Mr. SHIMKUS. Even though I am a big fan of the railroads, the question is posed in the way cheapest and safest. I mean, I think the basic answer is, if you are in logistics, and I kind of played in a little bit, moving bulk commodity products, liquid, through pipelines is the cheapest and the safest way, followed by then barge? This is just logistics. And then rail, and then trucks. That is pretty much assumed to be correct. OK. This is an infrastructure discussion, but there are places where pipelines can't go. The waterway system is not there, and that is why you need the whole logistics tale.

But I am concerned that we are not moving fast enough because of these changing in commodity products in expanding our pipeline system. I have been dealing with a local retailer, and I am not going to name the companies or the pipeline, but in the e-mail transactions that I have dealt with a couple times, he says FERC allowed X pipeline to discontinue shipping ultra-low sulfur diesel on its blank pipelines. The pipeline testimony to FERC to remove one of the two pipelines from south to north service, they claimed that there would be no impact in their capacity or ability to ship refined products. FERC allowed the line to be switched to a north-south service to ship methane from Pennsylvania to the Gulf Coast. This is now the X pipeline. They protested, FERC found in favor of the pipeline. Refined products were impacted because of discontinued ultra-low sulfur diesel shipment.

Andy, you mentioned about it. You mentioned changing the flow based upon the need. They also have a responsibility to meet the service of the folks who are on that line. So when you repurpose the product, there is a risk of not servicing the people on the line. Does that make sense to people? What is the solution to that? Go ahead. Mr. Black, would you answer that, please, first, and then we will see if anybody else wants to chime in?

Mr. BLACK. So you have got rail, truck, pipeline here at this hearing, and you could have barge, as you say. Liquid energy products can be transported on any mode, and so the transportation competition is intense. There is also no regulation, no obligation to serve customers in liquids. So the reversals that Mr. Tonko was asking about are a reaction of pipeline operators to developments in the market. Right now we had underutilized pipelines moving up that direction because shippers weren't asking for that pipeline to be used. Pipeline operator who can lose business like that wants to find a better economic use of the asset. Pipeline operator finds customers who want to ship product in a different direction, and they will reverse the pipeline.

That is the easiest way to add capacity into a market today. It is cheaper and quicker than building a new pipeline. So the story of the ATEX pipeline, which had been taking refined products north, and is taking——

Mr. SHIMKUS. You told——

Mr. BLACK [continuing]. Out——

Mr. SHIMKUS. You ratted me out. I was——

Mr. BLACK. Sure. No, I think it is fine to discuss that. There is propane capacity available today on the northbound TAPCO, and it is available for propane shippers to use it. And if they will use it throughout the year, there will be more than enough propane supply into those regions. I encourage you all to not think that reversals are a problem. Reversals are a way to satisfy shipper needs.

Mr. WHITFIELD. Gentleman's time is——

Mr. SHIMKUS. Mr. Chairman, if I could just say, the real solution is to build another pipeline too, my guess would be, because it is not just propane, it is other products.

Mr. WHITFIELD. His time has expired, but, Mr. Roldan, you wanted to make a comment?

Mr. ROLDAN. Yes. Just very quickly, I will tell you that, if you look at how natural gas pipelines are regulated, versus oil pipelines, there is a big difference, because on the natural gas side, if you wanted to discontinue a service, the commission takes into consideration who is affected by that. The same doesn't happen on oil pipelines. So if you look at the Midwest, and you look at the extraordinary tightness we felt this year, consider the fact that you have the Cochin pipeline, that goes from Alberta and serve the upper Midwest, 40 percent of the propane sold into Minnesota came into Minnesota from that pipeline. That pipeline is now out of service, and has been reversed. You look at the ATEX line, has been reversed, and those products are moving over.

So it is having an effect, and what we are saying is we think somewhere in the equation FERC should be able to have the obligation to consider what the impact is of those business decisions on the customers that depend on those pipelines.

Mr. WHITFIELD. Did you have a comment, Mr. Whittington?

Mr. WHITTINGTON. Storage is really important on the pipeline. A very current example downstate from St. Louis area, they reversed a pipeline. Two loading facilities there, because of the current demand, the weather, and everything else, their storage only lasted for three or four days, then we are out of product. We have got to go 200 miles to the next facility to pick up product to come back in. Time of the year is the other thing. You know, it is kind of like here, when you have a snowstorm, send your wife to the store to get the milk. If you are 2 hours late, there is no milk. But 300 days out of the year, there is plenty of milk on that rack for everybody to have.

So I think we don't want to lose sight of some of the stuff being seasonal stuff, but storage will be king. That is the problem with all the stuff in the Northeast. They are spending all the money to make the plants, they are going so quick, but storage is not on their priority list. It will be in a couple years, and then that is where you get the bottlenecks, and you get people running out.

Mr. WHITFIELD. All right, thank you. At this time I would like to recognize the gentleman from Illinois, Mr. Rush, for 5 minutes, and I would like to say, we are delighted to have you back, Mr. Rush, and look forward to working with you as we move forward.

Mr. RUSH. Thank you, Mr. Chairman, and it is a delight to be back again with this subcommittee, and the entire Congress. And we have continued to work, and I missed spending every Monday, Wednesday, and Friday of my life here in a subcommittee hearing, so I am glad to be back in the saddle again.

My question is directed to Mr. Roldan. Mr. Roldan, we have heard that the propane shortage in the Midwest was caused by a sort of "perfect storm" of contributing factors all converging at the same time, turned out to be a lot of distress and a lot of heartache for many of our constituents. And here on Capitol Hill, there were a variety of letters going out to everyone that you can think of, from President Obama, to the Department of Transportation, calling for a wide range of remedies, including relaxing weight requirements on the roads and highways, to lifting DOT's hours of service limitations for motor carriers, as well as a host of other potential solutions.

And the question that I have for you today, are there any legislative actions that you could recommend that we can take to prevent these types of shortages from happening in the future, or do the various agencies and entities that work in this propane market have the tools necessary to prevent this issue from happening again next year, or somewhere down the line? Similarly, I would ask if you could comment on the impact that exporting propane gas, which, by the way, increased eightfold from 2005 to 2013—what impact does our exporting propane gas have on the supply that is needed in the Midwest and across the nation?

Mr. ROLDAN. Thank you, Congressman. That is a very long question, so I am going to try to dissect it. We believe it is incumbent upon our industry to, first of all, understand the root causes and contributing factors of what took place this year, and then educate our members so that we never find ourselves in this situation again.

Now, I would like to point out that, of our 3,000 retail distributors, the vast majority worked very hard, and did a really good job reliably serving their customers. But we know that we are going to come forward after our task force, an industry task force that was put together, examines the situation, we are going to come back with some concrete policy proposals, and I can tell you they are going to come down in a couple of areas. We want to increase transparency, so that we know that our markets are functioning lawfully and transparently. We want to put in place in statute, and in regulation, consumer protections so that when changes are made, and storage and transportation assets are taken out of service, somebody asks the question, how are these affecting consumers that rely on these products?

We are going to take a look at export policy, because, as I said just a moment ago, there is a range of options that we think responsibly could let us continue to increase production, but at the same time strengthen our ability to reliably serve our customer. And then, finally, the areas of transportation efficiency and storage, I want to talk just a brief second about storage. I know you are time limited here. Give you a good example, I am sorry Mr. Tonko left, because this affects the State of New York. We talk about public storage, private storage. We have a company that is in the process right now of trying to put in 88 million gallons of storage, underground storage, in the Finger Lakes region of New York. That has been ready to go. It is fuel——

Mr. RUSH. Mr. Roldan, excuse me for interrupting you——

Mr. ROLDAN. Please.

Mr. RUSH [continuing]. But I do have another question that I really want to get to, so I want to get to my second question.

Mr. ROLDAN. That is good. And if I can follow up for the record?

[The information follows:]

NPGA
NATIONAL PROPANE GAS ASSOCIATION

March 18, 2014

The Honorable Ed Whitfield
Chairman, Subcommittee on Energy and Power
House Energy and Commerce Committee
U.S. House of Representatives
Washington, D.C. 20515

The Honorable Bobby Rush
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Chairman Whitfield and Ranking Member Rush:

On March 6, 2014, the Energy and Power Subcommittee held a hearing titled, "Benefits of and Challenges to Energy Access in the 21st Century: Fuel Supply and Infrastructure," during which I testified on behalf of the 3,000 members of the National Propane Gas Association (NPGA). I would like to provide the Subcommittee with a more complete answer to one of the questions posed by Ranking Member Rush: What needs to be done legislatively to prevent future shortages, and what effect do exports have on the industry?

In regard to what needs to be done legislatively, a few areas would help prevent future regional shortages:

1) Increased transparency
   a. Request the Federal Energy Regulatory Commission (FERC) regulate petroleum products pipelines similarly to natural gas pipelines (see 18 C.F.R. §358.1 *et seq.*);
   b. Amend Sections 15(13) and 15(14) of the Interstate Commerce Act so that identities of shippers and aggregate volume data can be made available in a timely manner;
   c. Similar to natural gas pipeline requirements, require FERC to make available petroleum products pipeline data on pricing, rates, volumes, etc.;
   d. Require the U.S. Energy Information Administration (EIA) to collect more detailed data on propane, such as separating propane from propylene, more detailed inventory data on storage providers, separate pricing data for different types of sales (residential vs commercial vs agriculture, etc.), transportation data including costs.

2) Research
   a. Require Federal Trade Commission (FTC) to assess the markets of the previous winter and determine areas of concern, if they exist;
   b. Review the market concentration and ownership of propane pipelines and determine whether market conditions are injuring consumers, including concerns for monopoly conditions of merchant, trading, and export functions
   c. Study supply, demand and exports to determine what role exports played.

3) Federal Emergency Authority
    a. Revise existing emergency authority to give Secretary of Transportation and Secretary of Energy the ability to exercise emergency authority with greater flexibility and specificity.

4) Other
    a. Require the Department of Commerce, when undertaking the price analysis required by Section 9 of the Propane Education and Research Act of 1996 (P.L. 104-284), to utilize existing EIA data on consumer propane prices reported by the EIA in the "Propane (Consumer Grade)" column on *Table 2, U.S. Refiner Prices of Petroleum Products to End Users;*
    b. Extend the alternative fuel excise tax credit (6426(d)) and alternative fuel refueling property credit (30(c)) to incentivize increased year-round use of propane (versus seasonal demand), which encourages expanded propane delivery infrastructure;
    c. Expand the Environmental Protection Agency (EPA) *Corporate Average Fuel Economy (CAFE) Standards* to provide an incentive multiplier for CO_2 emission compliance for propane autogas vehicles, similar to those that EPA issues for natural gas vehicles – again expanding year-round demand.

In regard to the role exports played, during the winter of 2013/2014 as supply constraints emerged and as prices spiked, many consumers and members of the propane industry questioned whether these events were caused by the growing exports of propane. Over the past four years, exports of propane from the Gulf Coast have increased dramatically as new export facilities have been developed and brought online. Based on the number of additional projects designed to increase export capacity that are currently under construction or have been announced, this growth trend is expected to continue.

NPGA has commissioned a study to examine the propane export question. Further in-depth analysis is, however, needed, and NPGA will request that EIA conduct a study of propane supply, demand, and exports similar to the study it conducted with respect to Liquefied Natural Gas (LNG) exports. Should policy action with regard to exports be deemed necessary, there are a variety of broad options to be considered. Congress, of course, has plenary authority to enact a new law that addresses this issue in any fashion that it determines to be in the interest of the United States.

It is my hope that these details have been helpful. Thank you again for the opportunity to testify before the Subcommittee and please let us know if we can ever be helpful in the future.

Sincerely,

Rick Roldan

Richard Roldan
President & Chief Executive Officer
National Propane Gas Association

Mr. RUSH. Mr. Santa, I have been working with the Department of Energy and various industry stakeholders to increase minority participation and engagement in all sections of the energy field, including gas and oil, renewables, coal, nuclear, and pipeline. And I want to work with your association as well to find out how we can increase the visibility of the natural gas industry in minority communities. And I wanted just to let you know that I look forward to working with you in the future. But can you kind of summarize what you think the status of your agency's, or your association's, participation with minorities, and women-owned businesses?

Mr. SANTA. Mr. Rush, I don't know what the numbers are with regard to the interstate natural gas pipeline industry and INGAA's members. That is certainly something that we can inquire about. I do know that, you know, our members are very active in trying to promote employment opportunities across the board, and also that, you know, overall I think the energy revival we have had in the United States has created tremendous job opportunities across the board, ranging from information technology to a lot of blue collar jobs that are very high paying. But with regard to specifically...

Mr. RUSH. Are there any minority members——

Mr. SANTA. Yes.

Mr. RUSH [continuing]. Who are part of your association?

Mr. SANTA. Excuse me?

Mr. RUSH. Are there any minority members who are part of your association? Minorities, women.

Mr. SANTA. Our membership is made up of the owners of interstate natural gas pipeline companies, so they are large corporations, as opposed to small businesses that might be woman or minority owned.

Mr. WHITFIELD. You might want to follow up by request. At this time I would like to recognize the gentleman from Nebraska, Mr. Terry, for 5 minutes.

Mr. TERRY. Thank you, and I appreciate this opportunity to ask a fundamental question that has kind of been hinted at, at least in the State of Nebraska, from those that rely on propane, so I want to ask the question directly. By the way, Jeff Fortenberry and I were both discussing this, so I will say I will ask it on his behalf as well as mine.

And I wanted to start with Mr. Santa, and go down the line. Are you aware of any allegations of fraud or manipulation to increase the price of propane during what would be, on the surface, a unique confluence of events? Is there fraud or manipulation in the background? Mr. Santa?

Mr. SANTA. Mr. Terry, given that INGAA represents the interstate natural gas pipelines, we have not followed the propane situation closely, other than to note its coverage in the trade press and the media. Based on what I have seen there, I cannot say that I have seen anything that would alert me to such allegations.

Mr. TERRY. Thank you.

Mr. ROLDAN. I am not aware of any specific allegations of manipulation, but I can tell you this. I can't explain the price anomaly that took place at Conway, Kansas over a 10 day period. We represent a lot of Midwestern retail marketers, and their customers, and they are all asking the same question, which is, how can this happen? I understand that volatility is associated with markets, but we think our customers demand the assurance that our markets are functioning properly and lawfully, and so do our members. And that is why we have taken the position to support Senator Grassley and other Members of Congress——

Mr. TERRY. Is that a yes or no? Because I only have——

Mr. ROLDAN. Yes.

Mr. TERRY [continuing]. 13——

Mr. ROLDAN. I am asking——

Mr. TERRY [continuing]. 3 minutes.

Mr. ROLDAN. I am urging the FTC to examine the transactions related to that run-up in price to——

Mr. TERRY. All right. That was actually a follow-up question to you, so you might as well keep going.

Mr. ROLDAN. OK. Well, all right.

Mr. TERRY. Why do you think the FTC needs to do an investigation?

Mr. ROLDAN. Really, because I think that our customers saw that price increase, and they are looking at us, saying, is everything on the up and up? And we need to give them the assurance that our markets are functioning properly. And the FTC is the only agency that can do that.

Mr. TERRY. All right. Mr. Logan?

Mr. LOGAN. I have no perspective on that.

Mr. TERRY. You haven't heard anything? All right. Mr. Whittington?

Mr. WHITTINGTON. I can tell you that we have customers that the freight this year was almost a dollar difference between where they generally get their propane and where we had to pick it up. $1 in freight. Didn't make any difference what the——

Mr. TERRY. So you are saying the freight charges spiked?

Mr. WHITTINGTON. Well, it takes a lot of money to go 800 miles instead of 16 miles. And so what happens there, that, you know, the product wasn't where it needed to be, and we had to go get it. And I can also tell you that if we hadn't been able to enjoy the hours of service exemption, we would have had to have twice as many trucks, and the expense would have been much greater than that to supply the demand.

Mr. TERRY. Mr. Obeiter, anything?

Mr. OBEITER. This is not an issue I follow closely.

Mr. TERRY. Mr. Black?

Mr. BLACK. From the perspective of a transporter that doesn't own the products being shipped——

Mr. TERRY. Yes.

Mr. BLACK [continuing]. Short answer, no.

Mr. TERRY. All right. This is a question that Mr. Sieminski was probably best apt to answer, and I am disappointed that he wasn't able to stay, but I will submit a written question to him, Mr. Chairman. So at this point, that answered my question. I wanted to follow up with the FTC question, and you answered that in the first part, so I will yield back my time.

Mr. WHITFIELD. Gentleman yields back. At this time I recognize the gentleman from California, Mr. Waxman, for 5 minutes.

Mr. WAXMAN. Thank you very much, Mr. Chairman. In North Dakota and Texas, crude oil production from shale formations has expanded very quickly. In these areas, oil wells often don't just produce oil. They produce natural gas, propane, butane, and other fuels as well. As oil production has boomed, so has the amount of natural gas and other fuels produced. That should be good news to the producers. The companies could capture this gas and sell it, but far too often the oil companies simply flare the natural gas. They treat it as little more than waste. In 2012, 32 percent of the natural gas produced in North Dakota was flared, burning gas valued at $560 million.

But more than potential profits are disappearing into the air. This flaring creates carbon dioxide and smog forming pollutants as well. The flaring of a valuable and finite natural resource is nothing less than a market failure. Something is going wrong here. Mr. Logan, is it economic to capture the natural gas, rather than to flare it?

Mr. LOGAN. Certainly in North Dakota it is. I mean, I think we have heard from the North Dakota industrial commission, as well as from some of the industry itself, that, you know, because of the unique nature of the gas being produced in North Dakota, it is not a dry gas. It is not just methane that you would get, you know, say, in the Marcellus, but it is very rich in liquids like propane and butane. So the economics of capturing it are actually quite good.

Mr. WAXMAN. Well, if it is profitable to capture the natural gas, rather than flare it, why aren't more companies doing it?

Mr. LOGAN. Well, it is really all about the relative economics, and also the state of regulation in places like North Dakota. So while it is profitable to capture the gas, it is more profitable to drill the next oil well. So if you are an oil company with a limited amount of money to spend, as they all are, you know, it is a somewhat rational short term choice to say, well, look, if I don't have the capture the gas, I would rather spend that money to drill another well. When you think of the long term, that is very short-sighted, actual wasted value of the resource, but you can kind of see, you know, why the market is pushing companies in that direction.

Mr. WAXMAN. Tell me the role of regulations on flaring in North Dakota and other States. Does it perpetuate the problem because the regulations are too lax? And what kind of regulations would move them in the right direction, if——

Mr. LOGAN. Yes. I mean, I think if you——

Mr. WAXMAN [continuing]. Profit motive is not enough?

Mr. LOGAN. I think all you have to do is look at the difference in flare rates between a North Dakota and a place like an Alaska, or a Texas. You know, in Alaska, flaring is basically non-existent because the State has mandated that you are not allowed to flare. In Texas, the flaring rate is less than one percent, compared to, you know, 36 percent in North Dakota, and that is because, you know, for all the issues in Texas, and flaring is a problem there, the regulatory presumption is not to allow flaring, and to do so only in limited and very time limited circumstances.

In North Dakota, you have a situation where, while the regulations on the books are not necessarily bad, the way that they are enforced, and the high degree of exemptions that are granted, mean that, essentially, you know, industry has carte blanche to flare certainly for up to a year, and often beyond that. So I think, you know, the fact that flaring is cheap, and free, and easy, certainly means you are going to get a lot more of it.

Mr. WAXMAN. So instead of investing in infrastructure that would be necessary to capture the gas, companies choose to flare it off, where regulations allow them to do so?

Mr. LOGAN. That is right. And it is a billion-dollar-a-year opportunity in somewhere like North Dakota, once you factor in the value of the liquids. And, you know, as I mentioned in my opening remarks, there is a lot of innovation going on in North Dakota. I mean, companies from, you know, small start-ups, to big companies like GE, coming up with new technologies to capture the gas, to liquefy it, to move it without pipelines. But without the right signals going to the market in the form of regulation, you know, none of that really gets off the ground.

Mr. WAXMAN. Now, Mr. Roldan, the upper Midwest has experienced significant shortages of propane this winter. Do you think it makes sense for oil companies to be flaring off natural gas liquids, like propane, that Americans need to heat their homes and farms, to dry their crops?

Mr. ROLDAN. Actually, that is a really good point. Consider the irony here. You are a North Dakota propane marketer, you are having trouble getting supply. You are driving all the way to the Texas Gulf Coast to pick up a load of product, and you are driving through fields as the sky is lit up with flaring. It doesn't make a lot of sense.

Mr. WAXMAN. Does anybody on the panel think this makes sense, to allow this kind of flaring? My time is up, almost, I have a few seconds left, but, Mr. Chairman, the wasteful and unnecessary flaring of natural gas is a serious problem. It has no place in a modern energy infrastructure. Mr. Rush, Ms. DeGette and I have previously requested that we hold a hearing on this specific issue.

I still believe the subcommittee should hold a hearing to get the facts regarding flaring, and to develop real solutions to the problem. So I want to reiterate that point to you. And it just seems to me there is a market failure, because even though they can make a lot of money, they are making more, or they are making enough, and not doing what they should be doing. And if the market is not working, that is when regulations step in. Yield back my time.

Mr. WHITFIELD. Thank you, Mr. Waxman, and thank you all for raising this issue in the hearing today. And at this time I would recognize the gentleman from Ohio, Mr. Latta, for 5——

Mr. LATTA. Well, thank you very much, Mr. Chairman, and thanks very much for our witnesses for being here with us. This is a really important issue because, in my district, we have had a real issue with propane this winter. Had a lot of meetings, a lot of discussions, and also here in Washington with letters for the hours of service for folks, and also we sent letters out on the issue of how much weight a truck could be hauling at that time.

This week we also had a bill on the floor from Chairman Shuster from the Transportation and Infrastructure Committee that I was on the floor with, again, that, you know, it is a real issue. I mean, looking at the Midwest, and we have had a very, very cold winter.

If I could start with Mr. Whittington, you know, you were talking about some of the barriers out there for increasing storage for capacity out there. You know, what could overcome that problem that we are having for storage?

Mr. WHITTINGTON. From my understanding, there is some storage that is available. It has been checked, but there are some regulatory things that are real fine line that is not letting that storage come into play. So there are some regulations that may be overregulating some of that kind of stuff. The other thing is, and I appreciate the comments from Congressman Waxman there, we need to look at the infrastructure that is going to be coming out of the Pennsylvania/Ohio/West Virginia stuff that is going to be able to take care of the Midwest. We are just not there yet. It is 2 or 3 years away before we are going to be able to take care of that product.

The indication that we are getting, the industry has been looking at that, and once that is up and going, you are going to have an oversupply in the Midwest. This is all new. It has never been here before. And that is what has really causing a lot of problems.

Mr. LATTA. Mr. Roldan, you know, if I can go back to you, I know that the gentleman from Illinois was asking this question to you about the Finger Lakes, and the storage potential up there. Can you talk about how this proposed facility would help, and what has been the delay in getting it done?

Mr. ROLDAN. Yes. It is private investment, private capex, 88 million gallons of storage in the Finger Lakes region. It is ready to go right now. We have been waiting on the decision from the Governor for quite a long period of time. I am not here to be critical, but I just want to emphasize how different the situation would have been this year if we had that 88 million gallons of storage. Because what the forced people to do without it, in the Northeast, is to travel to western supply hubs, like Sarnia, Ontario, which also supplies the Midwest, and compete with Midwestern marketers for product in Sarnia. It also required Northeastern marketers to go south, and compete with Southeastern marketers for product off the Dixie pipeline.

So you are talking about storage that could have helped alleviate the situation not just in the Northeast, but in the Midwest and the Southeast as well.

Mr. LATTA. Thank you. And also, Mr. Santa, I figured I would ask this question. You know, we are talking about where it is in the country you see the greatest demand for new pipeline development, it was just brought up by Mr. Whittington, especially in Ohio, with the Utica Shale, and over in Pennsylvania, with the Marcellus. Where do you see in the next 10 years that we are going to have to have a lot of pipeline development in this country to really move that product where it needs to be?

Mr. SANTA. That is a very good question, and it is one of the things that will be addressed by the INGAA Foundation study that is going to be released on March 17. However, looking in the nearer term, I note that I saw a recent financial analyst report that noted that within the next 3 years there was going to be nine billion cubic feet of proposed new pipeline capacity that could enter service to transport Marcellus Shale natural gas.

Some of that will be transporting the gas to markets in the Northeast and the Mid- Atlantic, but a lot of it will be taking that supply to the Southeast and the Gulf Coast, because the Marcellus production is literally overwhelming the demand in the Mid-Atlantic and Northeast markets. The demand is largely industrial, some electric generation, but also some anticipation of LNG exports.

Mr. LATTA. Thank you. And, Mr. Black, also in your testimony you stated that the country would benefit from more pipeline capacity. What do you see that needs to be done to get that capacity?

Mr. BLACK. Well, just like Don Santa said for natural gas pipelines, there is a need for new liquids pipelines for increased crude oil production. That is North Dakota, the Utica, hopefully, and Texas. Similarly, natural gas liquids. The phenomenon he is talking about, and Mr. Whittington talked about, about the Marcellus Shale, and the overwhelming production there, means there is a need to move more natural gas liquid products to where industrial workers can add value to them.

So throughout a lot of the country, because of our energy revolution that we are having, there is more that needs to be built. Oil and Gas Journal estimated last year $23 billion on liquids pipeline projects, and when I talked to execs, we find that that is probably low. There are thousands of miles of pipeline projects that are on the books today. We would be delighted to build some more capacity for propane shippers who want to sign up for long term service as well.

Mr. LATTA. Thank you very much. Mr. Chairman, I see my time has expired, and I yield back.

Mr. WHITFIELD. Well, thanks very much. Mr. Roldan, I just want to follow up with one question. I am not an expert in this area, but I have been told that in Texas the natural gas is wet natural gas, and that up in the Dakotas it is more of a dry natural gas, and therefore there is more propane in the wet natural gas. Can you elaborate on that, or am I——

Mr. ROLDAN. Actually, that is not my understanding, Mr. Chairman. I think the natural gas in all the northern formations is pretty wet.

Mr. WHITFIELD. In the northern formations it is——

Mr. ROLDAN. That is correct. In fact, when you look at the commodity price of natural gas which is down here, it is actually the value of the gas liquids, the propane, I think, that is driving production.

Mr. WHITFIELD. OK. Holding the value that is——

Mr. ROLDAN. Value of the gas liquids.

Mr. WHITFIELD. OK. All right. Well, I think that concludes today's hearing. Once again, I want to thank you all for your patience, and it has really been enjoyable being with you the last 3 ½ hours here. And we look forward to working with all of you as we move forward on this very important subject matter. And, with that, the hearing record will remain open for 10 days, and if we have any additional questions, we will get them to you, and would appreciate your response. So that concludes today's hearing. Thank you very much.

[Whereupon, at 12:03 p.m., the subcommittee was adjourned.]

[Material submitted for inclusion in the record follows:]

FRED UPTON, MICHIGAN
CHAIRMAN

HENRY A. WAXMAN, CALIFORNIA
RANKING MEMBER

ONE HUNDRED THIRTEENTH CONGRESS
Congress of the United States
House of Representatives
COMMITTEE ON ENERGY AND COMMERCE
2125 Rayburn House Office Building
Washington, DC 20515–6115
Majority (202) 225-2927
Minority (202) 225-3641

March 26, 2014

The Honorable Adam Sieminski
Administrator
U.S. Energy Information Administration
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Dear Administrator Sieminski:

Thank you for appearing before the Subcommittee on Energy and Power on Thursday, March 6, 2014, to testify at the hearing entitled "Benefits of and Challenges to Energy Access in the 21st Century: Fuel Supply and Infrastructure."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Wednesday, April 9, 2014. Your responses should be e-mailed to the Legislative Clerk in Word format at Nick.Abraham@mail.house.gov and mailed to Nick Abraham, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, D.C. 20515.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Ed Whitfield

Ed Whitfield
Chairman
Subcommittee on Energy and Power

cc: The Honorable Bobby L. Rush, Ranking Member,
Subcommittee on Energy and Power

Attachment

Department of Energy
Washington, DC 20585

April 14, 2014

The Honorable Ed Whitfield
Chairman
Subcommittee on Energy and Power
Committee on Energy and Commerce
U. S. House of Representatives
Washington, DC 20515

Dear Mr. Chairman:

On March 6, 2014, Adam Sieminski, Administrator, Energy Information Administration, testified regarding "Benefits of and Challenges to Energy Access in the 21st Century: Fuel Supply and Infrastructure."

Enclosed is the answer to one question that was submitted by Representative Lee Terry to complete the hearing record.

If we can be of further assistance, please have your staff contact our Congressional Hearing Coordinator, Lillian Owen, at (202) 586-2031.

Sincerely,

[redacted]

Christopher E. Davis
Principal Deputy Assistant Secretary
for Congressional Affairs
Congressional and Intergovernmental Affairs

Enclosure

cc: The Honorable Bobby L. Rush, Ranking Member

QUESTIONS FROM REPRESENATEIVE LEE TERRY

Q. In light of the data presented prior to and during the spike of propane prices, do you believe that an investigation by the FTC is warranted?

A. EIA does not usually state a view as to whether an investigation is warranted or not, as this is a policy issue. However, EIA does have some limited information that might help other agencies decide whether or not a review or investigation is warranted. The retail prices EIA reports are state averages collected by the state energy offices. EIA provides funding support for states to participate in the State Home Heating Oil and Propane Program (SHOPP) http://www.eia.gov/petroleum/heatingoilpropane/. This supports efforts to monitor the heating fuel markets in each State, to publish weekly average retail prices, as well as to develop and maintain programs which provide financial assistance for heating costs to low-income residents. EIA also has republishing rights for the weekly statewide average wholesale prices collected by a private vendor.

FRED UPTON, MICHIGAN
CHAIRMAN

HENRY A. WAXMAN, CALIFORNIA
RANKING MEMBER

ONE HUNDRED THIRTEENTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON ENERGY AND COMMERCE
2125 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, DC 20515–6115
Majority (202) 225-2927
Minority (202) 225-3641

March 26, 2014

MR. Donald F. Santa
President and CEO
Interstate Natural Gas Association of America
20 F Street, N.W., Suite 450
Washington, D.C. 20001

Dear Mr. Santa:

Thank you for appearing before the Subcommittee on Energy and Power on Thursday, March 6, 2014, to testify at the hearing entitled "Benefits of and Challenges to Energy Access in the 21st Century: Fuel Supply and Infrastructure."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

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Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Ed Whitfield

Ed Whitfield
Chairman
Subcommittee on Energy and Power

cc: The Honorable Bobby L. Rush, Ranking Member,
Subcommittee on Energy and Power

Attachment

Questions for the Record, The Honorable Pete Olson

1) Can you describe the regulatory hurdles faced by the interstate gas pipeline industry in securing permits for new pipelines?

As discussed in my testimony before the Subcommittee last July 9th, regarding H.R. 1900, the interstate natural gas pipeline permitting process is complex. While the Federal Energy Regulatory Commission (FERC) has exclusive authority under the Natural Gas Act to approve the construction of proposed interstate natural gas pipelines and is the "lead agency" for the environmental review conducted pursuant to the National Environmental Policy Act, it is not the only agency that must act in order for construction of a proposed pipeline to proceed. A myriad of other federal and, in some cases, state permitting agencies must act, and all permits and approvals must be received in order to build the pipeline. Consequently, a pipeline project can be delayed if but one of many required permits is not issued in a timely fashion.

In late 2012, the INGAA Foundation released a report on permitting delays prepared by Holland & Knight LLP that was referenced in my July testimony. The report compared pipeline permitting delays before the enactment of the Energy Policy Act of 2005 (which included several provisions intended to improve the permitting process) with delays after enactment of this law. Notwithstanding the intent of the new law, the report found that permitting delays have increased in recent years. Specifically, of those companies surveyed, the number of delayed permits increased from 7.69 percent to 28.05 percent of permits, and the number of delays that lasted 90 days or longer increased from 3.42 percent to 19.51. So, not only are permitting delays become more prevalent, but the delays are for longer periods.

Further, the impact of these delays may be much greater than just the additional number of days needed to obtain the permit. For example, if the delay causes the pipeline to miss the limited season for construction in environmentally sensitive areas, the initiation of construction could be delayed for nearly another year.

These delays affect not only the pipeline project developer, but also the customers of the pipeline. For example, the pipeline developer might incur the cost of keeping construction crews on hold and even may incur damages if the pipeline ultimately misses the in-service date specified in its contracts with customers. Producers and marketers lose the opportunity sell their natural gas during the period that initiation of pipeline service is delayed and consumers likewise are deprived the additional opportunities to purchase natural gas during this period. Getting agencies to work together in reviewing pipeline projects, and resolving permitting decisions in a cooperative and timely fashion, is a key to getting necessary energy infrastructure built in response to market demand.

2) Have these hurdles made attracting new infrastructure more difficult?

While it rarely happens, a handful of interstate natural gas pipeline projects have been cancelled due to the inability to obtain permits or protracted delays in permitting. In fact, the permitting reforms that were included in the Energy Policy Act of 2005 and that would be perfected with the enactment of H.R. 1900 were intended to address this situation.

Overall, the natural gas pipeline industry has succeeded in attracting the capital investment needed to finance new infrastructure. Often multiple proposed pipeline projects and proposed enhancements of existing facilities compete for new market opportunities to transport natural gas.

Still, interstate pipeline industry's ability to attract capital on favorable terms could be adversely affected if it is perceived that the potential for unreasonable permitting delays (and perhaps ultimately not receiving a needed permit) created a level of risk not associated with other investment opportunities. Such capital would flow to other energy infrastructure investments that were exposed to relatively less risk or for that matter to investments outside the energy sphere. This ultimately would harm consumers and the economy, because pipeline rates necessarily will reflect the higher cost of capital.

The challenges will grow greater as pipelines build facilities in more densely populated areas that are in close proximity with both new supply areas and growing markets, and as some activist groups target natural gas infrastructure as part of pursuing broader agendas. For example, even with support from the governors of New York and New Jersey and the mayor of New York City, it took Spectra Energy four years to obtain all of the authorizations needed to build its New York/New Jersey project. Consequently, efforts to improve the efficiency of pipeline permitting are warranted.

FRED UPTON, MICHIGAN
CHAIRMAN

HENRY A. WAXMAN, CALIFORNIA
RANKING MEMBER

ONE HUNDRED THIRTEENTH CONGRESS

Congress of the United States

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Majority (202) 225-2927
Minority (202) 225-3641

March 26, 2014

Mr. Richard Roldan
President and CEO
National Propane Gas Association
1899 L Street, N.W.
Washington, D.C. 20036

Dear Mr. Roldan:

Thank you for appearing before the Subcommittee on Energy and Power on Thursday, March 6, 2014, to testify at the hearing entitled "Benefits of and Challenges to Energy Access in the 21st Century: Fuel Supply and Infrastructure."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

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Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Ed Whitfield

Ed Whitfield
Chairman
Subcommittee on Energy and Power

cc: The Honorable Bobby L. Rush, Ranking Member,
Subcommittee on Energy and Power

Attachment

NPGA
NATIONAL PROPANE GAS ASSOCIATION

April 8, 2014

The Honorable Ed Whitfield
Chairman, Subcommittee on Energy and Power
House Energy and Commerce Committee
U.S. House of Representatives
Washington, DC 20515

The Honorable Bobby Rush
Ranking Member, Subcommittee on Energy and Power
House Energy and Commerce Committee
U.S. House of Representatives
Washington, DC 20515

Dear Chairman Whitfield and Ranking Member Rush:

On March 6, 2014, the Energy and Power Subcommittee held a hearing titled, "Benefits of and Challenges to Energy Access in the 21st Century: Fuel Supply and Infrastructure," during which I testified on behalf of the 3,000 members of the National Propane Gas Association (NPGA). I would like to provide the Subcommittee with a more complete answer to Representative Pete Olson, who asked:

1. **Mr. Roldan, there are federal actions that can be taken in a crisis like the propane shortage we are working through. However, I understand that my home state of Texas also helped by waiving requirements that trucks moving propane out of state must be *from* Texas.**

   Mr. Roldan, you commented that "The State of Texas deserves specific recognition for its efforts, which were crucial in getting propane supplies out of the state to the rest of the country."

   Can you describe how this action was useful, and what other state actions were taken to help alleviate shortages?

The 2013/2014 winter was very challenging for the propane industry, beginning with a strong crop drying season and extending through months of colder-than-normal temperatures. NPGA members worked very hard to serve their customers, but there are many people who contributed to resolving, and are still working to resolve, the issues posed by this year's heating season. On behalf of the industry and our customers, NPGA wishes to thank these individuals and organizations for their commitment to finding both short-term and long-term solutions.

Governor Perry and the State of Texas deserves specific recognition for its efforts, which were crucial in getting propane supplies out of the state to the rest of the country. Texas is host to the largest primary storage of propane in the world, and many truck drivers from out of state traveled to Texas to obtain the fuel directly from the storage facilities near Mont Belvieu. Specifically, the state waived its permitting requirements for out-of-state vehicles, a process that can otherwise take as much as 30 days to complete. This allowed drivers from other states to immediately operate in Texas so they could transport their load back to their home state.

Many states including Texas granted Hours of Service (HOS) waivers, which have helped immensely. These waivers allow truck drivers to obtain needed propane from far-away places and deliver that propane to customers. Some states granted exemptions from weight limits for trucks traveling over state roads. While this does not allow drivers to carry overweight loads on interstate highways, it does help trucks carry additional fuel volumes up to the maximum amount of propane allowed by law even though the vehicle was overweight. A number of states have taken advantage of the Low-Income Home Energy Assistance Program (LIHEAP) to help consumers. At a time when we've seen unusually high prices, this program has provided much needed assistance to the customers who need it most.

Finally, we are grateful for the meetings with the Governors of numerous affected states, and the teleconferences with states' energy, transportation, and agriculture officials that were held, which allowed the sharing of credible real-time information and increased coordination among all parties.
It is my hope that these details have been helpful. Thank you again for the opportunity to testify before the Subcommittee and please let us know if we can ever be helpful in the future.

Sincerely,

[redacted]

Richard Roldan
President & Chief Executive Officer
National Propane Gas Association

FRED UPTON, MICHIGAN
CHAIRMAN

HENRY A. WAXMAN, CALIFORNIA
RANKING MEMBER

ONE HUNDRED THIRTEENTH CONGRESS

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Minority (202) 225-3641

March 26, 2014

Mr. Shorty Whittington
President
Grammer Industries, Inc.
American Trucking Association and the
National Tank Truck Carriers
18375 East 345 South
Grammer, IN 47236

Dear Mr. Whittington:

Thank you for appearing before the Subcommittee on Energy and Power on Thursday, March 6, 2014, to testify at the hearing entitled "Benefits of and Challenges to Energy Access in the 21st Century: Fuel Supply and Infrastructure."

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Sincerely,

Ed Whitfield

Ed Whitfield
Chairman
Subcommittee on Energy and Power

cc: The Honorable Bobby L. Rush, Ranking Member,
Subcommittee on Energy and Power

Attachment

U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON ENERGY AND COMMERCE
Subcommittee on Energy and Power

Response to Additional Questions for the Record
TO: The Honorable Pete Olsen

Benefits of and Challenges to Energy Access in the 21st Century: Fuel Supply and Infrastructure
FROM: Shorty Whittington

1. **Mr. Whittington, there are federal actions that can be taken in a crisis like the propane shortage we are working through. However, I understand that my home State of Texas also helped by waiving requirements that trucks moving propane out of the State must be *from* Texas.**

   Mr. Roldan commented that "The State of Texas deserves specific recognition for it's efforts, which were crucial in getting propane supplies out of the State to the rest of the country."

   Can you describe how this action was useful, and what other State actions were taken to help alleviate shortages?

Mr. Congressman Olsen, the propane, or LPG, shortages the country has experienced this winter have necessitated extreme measures to meet demand.

The tight supply and higher prices of LPG are being blamed on an assortment of factors:

- Huge demand by farmers to dry crops that were harvested last fall;
- An increase in exports;
- The shutdown of Cochin, a Kinder Morgan pipeline, to the Midwest in December for maintenance;
- Burdensome federal and State regulations which do not add to safety; and
- The extreme weather experienced across the country.

The U.S. Energy Information Administration reported in February that LPG stocks were 44 percent below the year-ago level due to its scarcity. Prices have risen to almost $4.00 a gallon, a staggering price hike.

Mr. Shorty Whittington QFR Response
Tuesday, April 1, 2014

These shortages have compelled suppliers to travel to Texas, Kansas, Mississippi, and elsewhere to get the necessary fuel. Typically, supplies for the Midwest are available at much shorter distances.

I concur with Mr. Roldan's comment in so far as Texas for taking responsible actions to ensure the safety of those requiring fuel across the country. I firmly believe, however, that the suspended State law is actually part of the problem, not part of the solution. Attempts by various States, including Texas and new Mexico for example, discourage efficient transportation of fuel supplies, do nothing to add safety, overlap existing regulations promulgated by the U.S. Department of Transportation, and place an undue burden on U.S. interState commerce.

The requirement for trucks moving propane out of the State which are not based in Texas must be registered with the Texas Railroad Commission is, at best, inequitable. The extensive licensing, inspection, testing and managerial fees administered by the Texas Railroad Commission place a large financial burden on suppliers, as well as inhibiting business operations.

Not only are these a one-time expense, they must be renewed annually, further inhibiting business operations and causing unnecessary delays. Furthermore, the fees do not increase safety in transportation; rather, the fee is deposited into the Texas General Fund for use in other areas.

Congressman, the federal regulations in place should preempt the Texas statute, as they take into consideration the interest of all transportation concerns. The Federal Hazardous Materials Transportation Act ("HMTA") provides safety by ensuring consistency in laws and regulations for inspections and test requirements. The conflicting requirements in Texas destroy uniformity and create unnecessary confusion, while discriminating against all out-of-State drivers and suppliers. This law is a logistical nightmare, with questionable legality. It would serve the country well to remove this inhibition.

The Texas Department of Public safety did waive limits on hours of service in Texas for fuel carriers providing emergency relief, along with numerous other States, to alleviate the shortage. This action merits recognition.

The actions taken by Texas were timely and sensible to assist those needing aid this winter. The action, however, should remain a permanent regulation for the State, in order to encourage safe and efficient interState commerce in the future and I highly encourage you to support the continued repeal of State laws which serve to thwart, rather than encourage, the timely and efficient flow of goods and commerce across our great Nation.

FRED UPTON, MICHIGAN
CHAIRMAN

HENRY A. WAXMAN, CALIFORNIA
RANKING MEMBER

ONE HUNDRED THIRTEENTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON ENERGY AND COMMERCE
2125 Rayburn House Office Building
Washington, DC 20515-6115
Majority (202) 225-2927
Minority (202) 225-3641

March 26, 2014

Mr. Andrew J. Black
President
Association of Oil Pipe Lines
1808 Eye Street, N.W., Suite 300
Washington, D.C. 20006

Dear Mr. Black:

Thank you for appearing before the Subcommittee on Energy and Power on Thursday, March 6, 2014, to testify at the hearing entitled "Benefits of and Challenges to Energy Access in the 21st Century: Fuel Supply and Infrastructure."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Wednesday, April 9, 2014. Your responses should be e-mailed to the Legislative Clerk in Word format at Nick.Abraham@mail.house.gov and mailed to Nick Abraham, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, D.C. 20515.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Ed Whitfield

Ed Whitfield
Chairman
Subcommittee on Energy and Power

cc: The Honorable Bobby L. Rush, Ranking Member,
Subcommittee on Energy and Power

Attachment

Andy Black
Association of Oil Pipe Lines
Answers to Questions for the Record
Subcommittee on Energy & Power Hearing March 6, 2014

The Honorable Ed Whitfield

1. **What are the jobs benefits of the proposed Keystone XL pipeline, the total number of direct, indirect and induced jobs their types, locations, economic benefits to workers, and overall economic beuefits?**

A. The proposed Keystone XL pipeline is expected to support approximately 42,100 direct, indirect and induced jobs with over $2 billion in worker earnings, according to economic analysis completed for the U.S. State Department's Final Supplemental Environmental Impact Statement (FSEIS) for the project.

Approximately 16,100 come directly from firms that are awarded contracts for goods and services, including construction, directly by the project sponsor. A further 26,000 would result from indirect and induced spending, consisting of goods and services purchased by the construction contractors and spending by employees working for either a construction contractor or for any supplier of goods and services required in the construction process.

Workers across the nation will benefit from Keystone XL-related jobs. While residents of the project area in Montana, South Dakota, Nebraska and Kansas would hold approximately 12,000 of the jobs associated with Keystone XL, residents in the rest of the United States would hold 30,000 Keystone XL jobs.

Furthermore, while Keystone XL will benefit construction workers, it will also benefit workers in good-paying jobs from manufacturing to service professions. Figure 1.10.1-2 from the FSEIS, copied below, breaks out worker earnings expected from the project. Not only will Keystone XL provide about $420 million in construction trade earnings, it will provide $309 million in manufacturing earnings, and $343 million in professional services and management earnings. Table 4.10-5 of the FSEIS, on the next page, describes in detail how Keystone XL will support 6,800 construction jobs, 4,600 manufacturing jobs, 5,100 professional services and management jobs, 5,700 jobs in accommodations and food services, 2,700 health and social services jobs, as well as numerous other trades and professions.

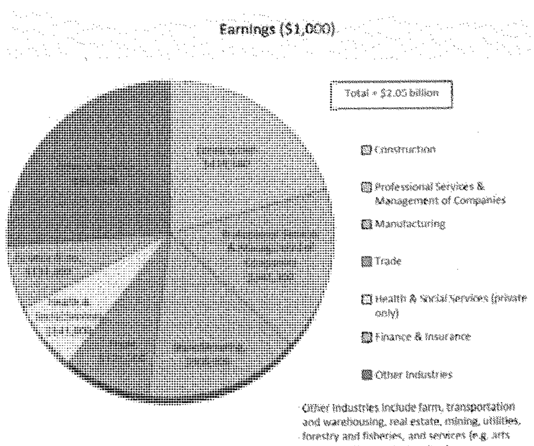

Table 4.10-5 Total U.S. Employment and Earnings by Industry Supported by Construction of the Proposed Project

	Employment (average annual jobs)			Earnings (thousands of 2010 dollars)[a]		
	Current (2010)	Total Effects of Proposed Project[a]		Current (2010)	Total Effects of Proposed Project[a]	
Industry	Jobs[b]	Jobs[b]	Share of 2010 Total	$1,000[c]	$1,000[c]	Share of 2010 Total
Farm	2,665,000	300	0.01%	77,215,000	7,400	0.01%
Forestry, Fisheries, & Support, including Farm Support	835,800	100	0.01%	22,548,000	3,800	0.02%
Mining	1,185,500	300	0.02%	83,081,000	28,300	0.03%
Utilities	579,000	100	0.02%	73,306,000	18,400	0.03%
Construction	8,914,200	6,800	0.08%	479,541,000	419,500	0.09%
Manufacturing	12,206,900	4,600	0.04%	891,607,000	308,900	0.03%
Trade	23,808,200	4,400	0.02%	1,009,713,000	172,100	0.02%
Transportation & Warehousing	5,504,400	2,000	0.04%	295,408,000	110,400	0.04%
Information	3,210,700	600	0.02%	294,252,000	40,100	0.01%
Finance & Insurance	9,651,300	2,200	0.02%	647,655,000	131,400	0.02%
Real Estate & Rental	7,459,200	1,600	0.02%	148,119,000	31,200	0.02%
Professional Services & Management of Companies	13,765,700	5,100	0.04%	1,110,322,000	343,300	0.03%
Administrative & Waste Services (private only)	10,478,800	2,300	0.02%	353,648,000	71,100	0.02%
Educational Services (private only)	4,076,600	500	0.01%	146,724,000	18,000	0.01%
Health & Social Services (private only)	19,062,300	2,700	0.01%	1,000,258,000	141,000	0.01%
Arts, Entertainment & Recreation Services	3,777,100	600	0.02%	100,953,000	13,600	0.01%
Accommodations & Food Services	12,048,000	5,700	0.05%	278,844,000	103,300	0.04%
Other Services	9,858,700	1,800	0.02%	330,361,000	62,100	0.02%
Government & Government Enterprises	24,680,000	400	< 0.01%	1,642,674,000	29,900	< 0.01%
Total	173,767,400	42,100	0.02%	8,986,229,000	2,053,800	0.02%

[a] Time period for realizing all effects is uncertain.
[b] Includes direct, indirect, and induced full-time and part-time jobs by place of work.
[c] Labor earnings by place of work

With current national policy debates over a federal minimum wage and income inequality, it is important to note the good-paying jobs and wages Keystone XL workers will receive. Factoring the number of expected jobs into the total expected earnings yields $67,152 in earnings per manufacturing job, $67,313 in earnings per professional services and management job, and $61,691 per construction job.

2. What is needed to encourage or ensure there is sufficient pipeline infrastructure development to meet the nation's energy needs?

A. Prompt review and permitting of pipeline projects, certainty as to the rates that pipelines will be able to charge to shippers, and commitment by shippers to use proposed pipeline projects are all needed to encourage pipeline infrastructure development.

Delayed government review and approval of pipeline construction projects can slow pipeline development. The most prominent example of increased permit delay is the Keystone XL project. The federal government issued a presidential permit for the largely similar Alberta Clipper project in a little over 2 years ending in 2010. However, total review time for the Keystone XL project has now stretched to over 5 years. Even a simple review, consisting of a change in the corporate name of a presidential permit holder, is facing a multi-year review.

Review of previously straight-forward nationwide permit (NWP) authorizations by the Corps of Engineers also seems to be slowing. Reports are growing of greater review times after a recent court challenge to the nationwide permit program and its application to the Gulf Coast pipeline from Cushing, OK to the Gulf Coast, even though that challenge was unsuccessful. There is also concern that limited Corps staff to review NWP authorizations is slowing processing times.

In order for project sponsors to construct pipeline infrastructure, they need certainty as to the rates that may be charged to shippers. Traditionally, project sponsors seek contractual commitments from potential shippers wishing to ship product on a proposed pipeline to ensure there is demand for the proposed pipeline and a commitment to pay the agreed upon rate and use the line over time. The project sponsor makes its investment and obtains financing for the project based upon these contractual commitments, and typically files a petition with the U.S. Federal Energy Regulatory Commission (FERC) seeking assurance that FERC will honor the sanctity of these contract commitments. Last year, a recommended decision issued by a FERC Administrative Law Judge (ALJ) hearing a rate case departed from established policy and found that the rates agreed upon in such shipper contractual commitments could be challenged and rejected. AOPL and others argued for FERC to reject the ALJ's recommendation, which it did. Continued preservation of this system of shipper commitments is vital to ensuring future financing of pipeline construction projects.

Lastly, shipper demand is necessary to ensure pipeline construction. Pipeline operators and project developers are eager to build new pipelines. However, demand from shippers wishing to commit to using the new line over time is necessary to justify the projects and obtain project financing. Demand for a specific project is contingent on many factors. Geographic location of supply and potential shippers, alternative modes of transportation, and projections of commodity pricing and demand in the future are some of the key factors that play into decision making. Regional production increases may indicate the potential for a new pipeline servicing that area. However, the right combination of specific pipeline route, competition from other modes of transportation, and alternative supply sources in the receiving markets are necessary for a proposal to go from the drawing board to construction.

3. To what degree will reversal of liquid pipelines currently servicing the Midwest impact regional propane deliveries?

A. Liquid pipelines operate in dynamic markets that are experiencing geographic shifts in supply and demand. These vastly changing market dynamics are causing changes in regional delivery patterns with respect to propane and other energy liquids. Pipelines are responding to these changes by not only constructing new facilities, but also by making efficient investments to increase capacity and reverse flows on existing systems to meet customer demand.

Historic propane pipeline usage patterns and available future space both indicate reversal of liquid pipelines in the Midwest will not have a material impact on propane deliveries over the long-term, and that market dynamics are driving the need for changes in pipeline flows. In the case of the Cochin line previously delivering propane from Alberta, Canada to the U.S. Midwest, that line was underused by propane shippers due to a precipitous decline in demand for propane shipments from Canada for over a decade. Increased oil and gas production in the U.S. has resulted in increased U.S. domestic production of propane, a natural byproduct of oil and gas production. Consequently, U.S. propane marketers are importing less Canadian propane and taking advantage of the abundant U.S. production. Reports put Cochin operating at only one-third of its total capacity. (Kinder Plans Cochin Pipeline Reversal, Calgary Herald, Apr. 24, 2012) Operators of Cochin made the decision to reverse Cochin because of Cochin's underutilization and strong market support to put the line to better use delivering other products.

Similarly, the development of the Marcellus Shale production region of Pennsylvania and Ohio is resulting in increased local supply of propane for Midwestern markets. This is reducing the need to transport propane from the Gulf Coast to the Midwest via the TEPPCO line owned by Enterprise Products Partners. TEPPCO, which includes two parallel pipelines, proposed retaining one of the lines to continue delivering natural gas liquids, including propane, from the Gulf Coast to the Midwest, and reversing the flow direction of the second line to carry new production from the Marcellus to Gulf Coast manufacturing markets. There was a concern voiced at the hearing that the new configuration would leave insufficient capacity for propane deliveries to the Midwest on the remaining TEPPCO line. As part of the regulatory process to allow the offering of southbound service on one of the two TEPPCO lines, TEPPCO analyzed the usage and capacity of the remaining northbound TEPPCO line. (FERC Docket No. OR13-20-000, p. 15) That analysis of the remaining northbound line demonstrated projected volumes of propane and other similar liquids at that time would represent only 74% of the capacity available to such products from the Gulf Coast to southern Illinois, and only 56% of the available capacity from southern Illinois to southern Indiana.

There is projected to be enough pipeline capacity to transport propane supplies where they are needed. Propane shippers can prepare for periods of high demand, like experienced this past winter, by shipping on pipelines to consuming areas and injecting these supplies into storage in advance.

The Honorable Pete Olson

1. **My home state of Texas is crisscrossed by pipelines. Ever since the early 1900s, they have been a fact of life for Texans. Modern pipelines mean quick and reliable access to affordable energy. They also have meant good-paying jobs for the men and women across even rural parts of this state.**

   However, it is becoming clear that we need even more pipelines. The Eagle Ford shale is booming. Production has spiked in just the last few years from 200,000 barrels of oil per day up to beyond 1.2 million While that is great news, we have seen that some regions grow so quickly that they move faster than their infrastructure allows.

   a. **Mr. Black, can you tell me some of the deciding factors when a company looks at a region and determines whether to build new pipelines?**

      The decision to build a new pipeline is based on many factors, including the availability and volume of supply at a proposed project's starting point and the demand for supply at its terminus, the desire of shippers to contract for usage of the pipeline, the cost to construct the pipeline, competing modes of transportation to deliver that product to market, and other siting, permitting and logistical challenges facing the potential pipeline. Projects must demonstrate their viability over the longer term to pay off construction financing and attract capital. This means customers must commit to use a proposed pipeline over the long term, and the return on investment must be adequate. Projections of customer demand, commodity prices, the cost of shipping product with alternative modes of transportation such as truck, rail and waterborne transportation, and customer desire for flexibility to change delivery volumes or locations, may all factor into whether a pipeline project gains the support to go forward.

   b. **What are some of the safety improvements that we see on pipelines compared to a decade or two ago?**

      Pipelines are the safest way to transport crude oil and petroleum products. A barrel of oil delivered by pipeline has a 99.999% chance of reaching its destination safely. Over the last 10 years, the overall number of pipeline releases are down over 60 percent, and volumes released are down over 40 percent. Specific causes of pipeline incidents, such as corrosion and 3rd party damage, are down almost 80%.

      That said, pipeline incidents do happen on rare occasions. This drives the pipeline industry's goal of zero pipeline incidents. To that end, pipeline operators spent over $1.6 billion in 2012 evaluating, inspecting and performing maintenance on their pipelines. In 2014, the pipeline industry launched the *Pipeline Safety Excellence*™ initiative reflecting the shared values and commitment of pipeline operators to building and operating pipelines. The initiative includes jointly held industry-wide pipeline safety principles such as zero incidents, promoting safety culture, organization-wide commitment to safety, continuous improvement, and learning safety lessons from experience. Pipeline operators engage in a range of industry-wide pipeline safety efforts, devoting personnel and resources to developing new pipeline standards and recommended practices, sharing safety lessons, and improving pipeline safety across the entire industry.

In 2014, the pipeline industry released its first annual pipeline safety performance report, sharing with the public in one place a range of pipeline safety data, reflecting both safety successes and areas needing improvement. Coupled with that, pipeline operators released a 2014 strategic plan containing seven different strategic initiatives to improve industry-wide pipeline safety. Over the next year, pipeline operators will improve pipeline inspection technology, develop industry-wide recommended practices to fight pipeline cracks, detect pipeline leaks, and respond to emergencies. Pipeline operators will also develop ways to better integrate data needed to keep pipeline safe, share, incorporate and measure safety learning, and implement comprehensive safety management programs.

FRED UPTON, MICHIGAN
CHAIRMAN

HENRY A. WAXMAN, CALIFORNIA
RANKING MEMBER

ONE HUNDRED THIRTEENTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON ENERGY AND COMMERCE
2125 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, DC 20515-6115
Majority (202) 225-2927
Minority (202) 225-3641

March 26, 2014

Mr. Edward R. Hamberger
President and CEO
Association of American Railroads
425 Third Street, S.W.
Washington, D.C. 20024

Dear Mr. Hamberger:

Thank you for appearing before the Subcommittee on Energy and Power on Thursday, March 6, 2014, to testify at the hearing entitled "Benefits of and Challenges to Energy Access in the 21st Century: Fuel Supply and Infrastructure."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

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Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Ed Whitfield

Ed Whitfield
Chairman
Subcommittee on Energy and Power

cc: The Honorable Bobby L. Rush, Ranking Member,
Subcommittee on Energy and Power

Attachment

ASSOCIATION OF
AMERICAN RAILROADS

Office of the President
Edward R. Hamberger
President and Chief Executive Officer

April 9, 2014

The Honorable Ed Whitfield
Chairman, Subcommittee on Energy and Power
House Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, DC 20515

Dear Chairman Whitfield:

Thank you for the opportunity to testify before the Energy and Power Subcommittee on March 6, 2014 regarding the transportation of energy products by rail. Enclosed, please find a response to your question for the record of this hearing.

Thank you for considering our views. If you or a member of your staff should have any additional questions, please feel to contact me at 202-639-2400 or John Wetzel of the AAR Government Affairs staff at 202-639-2538 or jwetzel@aar.org.

Sincerely,

[redacted]

Edward R. Hamberger

THE HONORABLE ED WHITFIELD
CHAIRMAN, SUBCOMMITTEE ON ENERGY AND POWER
HEARING ON BENEFITS OF AND CHALLENGES TO ENERGY ACCESS IN THE 21ST CENTURY: FUEL SUPPLY AND INFRASTRUCTURE
MARCH 6, 2014

QUESTIONS FOR THE RECORD
TO
MR. ED HAMBERGER, PRESIDENT
ASSOCIATION OF AMERICAN RAILROADS (AAR)

Q. Can you please explain the review process that is being proposed by the FCC for each and every one of these [22,000 antenna] poles and what kind of impact these reviews will have on deploying this new [Positive Train Control] technology?

A. The applicant railroad would begin work on a cultural resources report and the State Historic Preservation Office due diligence process several weeks prior to the intended application date for one or more sites. On day one, the applicant would then file a batch submission of locations in a particular county into the FCC's Tower Construction Notification System (TCNS). TCNS would send out electronic notices to tribes that have indicated interest in that particular county. Each individual pole location would need to be cleared by every Tribe that has indicated interest in TCNS at that location. In the absence of any response over the course of the next 20 days and assuming the applicant has made at least one follow-up inquiry, the applicant could then ask the FCC to send a letter/e-mail to the Tribe(s) in question. This would happen five business days following the applicant's request. On day 40, if there is still no response, then the sites in the batch would be considered cleared.

However, at any time during this 40-day period, a Tribe could request more information and/or compensation. If the Tribe does not respond after receiving additional information, the applicant may request that the FCC contact the Tribe(s) and give them an additional 15 days to respond. If there is no further response, the sites would be considered cleared.

If the parties have disputes regarding information or compensation that they cannot resolve after 15 days, they can bring them to the FCC to resolve. Also, if the parties have disputes about the identification of sites of cultural and religious significance or appropriate mitigation they can bring it to the FCC to resolve.

The FCC is required to resolve all disputes within 30 days, with one 30-day extension permitted. Further extensions are only to be granted upon extraordinary circumstances.

In terms of impacts, the fact is that railroad industry would not have been able to achieve the 2015 deadline even if there had been no delay attributable to the FCC. However, the delay in installation of the antennas has set back the timeline for rolling out PTC. Last May, AAR projected that by December 31, 2015, the industry would have rolled out PTC on 40 percent of the approximate 60,000 miles of route mileage required to be equipped with PTC. AAR has now reduced that December 31, 2015, projection to 20 percent of the PTC route mileage, and lacking a date certain by which approval to install PTC antennas will be granted, the industry cannot offer any additional projections.