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**BEFORE THE SENATE ENERGY AND NATURAL RESOURCES COMMITTEE**

**"OIL AND GAS PIPELINE INFRASTRUCTURE AND THE ECONOMIC, SAFETY, ENVIRONMENTAL, PERMITTING, CONSTRUCTION AND MAINTENANCE CONSIDERATIONS ASSOCIATED WITH THAT INFRASTRUCTURE."**

**TUESDAY, JUNE 14, 2016**

Chairman Murkowski, Ranking Member Cantwell, and members of the Committee, thank you for this opportunity to discuss some of the challenges and opportunities associated with natural gas pipeline infrastructure.

Environmental Defense Fund (EDF) is a national environmental advocacy organization with more than one million members and supporters nationwide. We are dedicated to finding innovative approaches to solving some of the most difficult national and international environmental challenges. Whenever possible, we collaborate with private-sector partners, state and federal leaders, and other environmental organizations interested in maximizing incentives for market-based solutions to environmental problems.

EDF is devoting considerable attention to our nation's natural gas pipeline infrastructure. EDF is represented on the Pipeline and Hazardous Material Safety Administration's (PHMSA) citizen advisory board for gas pipelines. We are active before the Federal Energy Regulatory Commission (FERC) in ongoing efforts by the agency to refine and improve the market rules governing natural gas pipeline operation and capacity expansion. EDF is a member of the North American Energy Standards Board (NAESB), where I have a seat on its Board of Directors.

As part of an ongoing multi-year effort to better understand the magnitude, causes, and solutions to methane emissions across the natural gas supply chain, EDF has participated in numerous peer-reviewed, published, scientific studies characterizing the problem of methane emissions from the nation's natural gas delivery system. As an outgrowth of this effort, EDF is playing an active role in shaping public policy in response to the catastrophic failure of an injection well at the Aliso Canyon gas storage facility in California this past fall.

In all of our work, EDF prides itself on working constructively with the oil and gas industry, federal and state policymakers and regulators, environmental and consumer advocates, and other stakeholders to achieve a gas delivery system in this country that is safe, reliable, efficient, and configured to support progress toward a low carbon future.

My testimony today will address opportunities to update natural gas wholesale market rules to better align with contemporary supply and demand dynamics, which in turn, will clarify the extent of need and commercial considerations attendant to new interstate natural gas pipeline capacity. I will also discuss the results of our relevant methane emissions studies and the opportunities these studies point to for reducing leaks across our nation's gas gathering, processing, transportation, distribution and storage system, and enhancing the integrity and reliability of this system. My bottom-line message is that there is much that we can do to improve the safety, reliability, and methane emissions performance of our nation's natural gas industry, and to ensure that investment in new pipeline infrastructure is right-sized, as we continue to move towards a cleaner, more efficient, renewable-centric and zero carbon energy future.

## Natural Gas Transportation Wholesale Market Design and Capacity Needs

Natural gas is playing a role in transitioning our nation to a cleaner, lower carbon future. Increased production and use of natural gas is helping to end our dependence on carbon-intensive, highly polluting coal for power generation. Fast-ramping natural gas fired generation helps integrate increasing amounts of renewable electricity generation into our nation's electric grid. And in places like New York City, natural gas is helping to displace high sulfur, dirty fuel oil for home heating, leading to dramatic air quality improvements in our largest city.

But these benefits come with significant environmental costs to the communities where the gas is produced. I will not dwell on the many issues associated with unconventional oil and gas development. They are real, but I respect the fact that this is not the topic of this hearing today.

I will, however, discuss the climate implications of natural gas infrastructure as these are germane to the issue of a safe, reliable, efficient gas delivery system. Simply put, the ability of natural gas to deliver on its promise as a cleaner, lower carbon alternative to coal and oil and as a transition to a low carbon future anchored by renewables, depends on whether we've designed the wholesale market rules to support the gas transportation infrastructure needed to achieve that future, and whether natural gas infrastructure is free from preventable methane leaks and losses, which unabated, eat away at some, if not all, of the climate benefit from substituting natural gas for coal or oil.

To start with, the energy system in the United States is in the midst of a massive transformation due only in part to prolific new and recoverable natural gas supplies. In parallel to the shale gas revolution has been a dramatic drop in the cost of renewable energy technologies, particularly wind and solar. Energy efficient lighting and appliances are entering the market and fundamentally changing the future trajectory of U.S. energy demand. Information technology applied to energy supply and consumption is enabling greater consumer control in delivery and use, and empowering greater customer choice. Taken together, these developments pose daunting implications for a natural gas market designed and organized at a time when coal was king, gas-fired generation was an afterthought and gas supply for manufacturing and industry was far less a consideration than it is today; and they raise major questions about the magnitude and economics of natural gas supply and consumption in the future.

It is increasingly apparent within the new supply and demand dynamics that there are opportunities to enhance system efficiency by better utilizing existing pipeline capacity. According to the Department of Energy (DOE), average capacity utilization for the interstate pipeline system between 1998 and 2013 was only 54%. (*Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector*, February 2015).

In fact, during the polar vortex event in January 2014, when it is widely believed that the interstate pipelines serving the northeast were totally full, EDF's detailed analysis of pipeline flows demonstrate that several large pipeline systems within the zone of perceived constraint had large amounts of unused capacity, even on the coldest days when gas and electricity spot market prices were at their highest. In addition, other pipelines, notably those with around-the- clock scheduling flexibility, often managed to deliver amounts of gas that exceeded their firm contracted capacity within the zone of perceived constraint. The accuracy of EDF's analysis has been confirmed with the implicated pipelines and market participants.

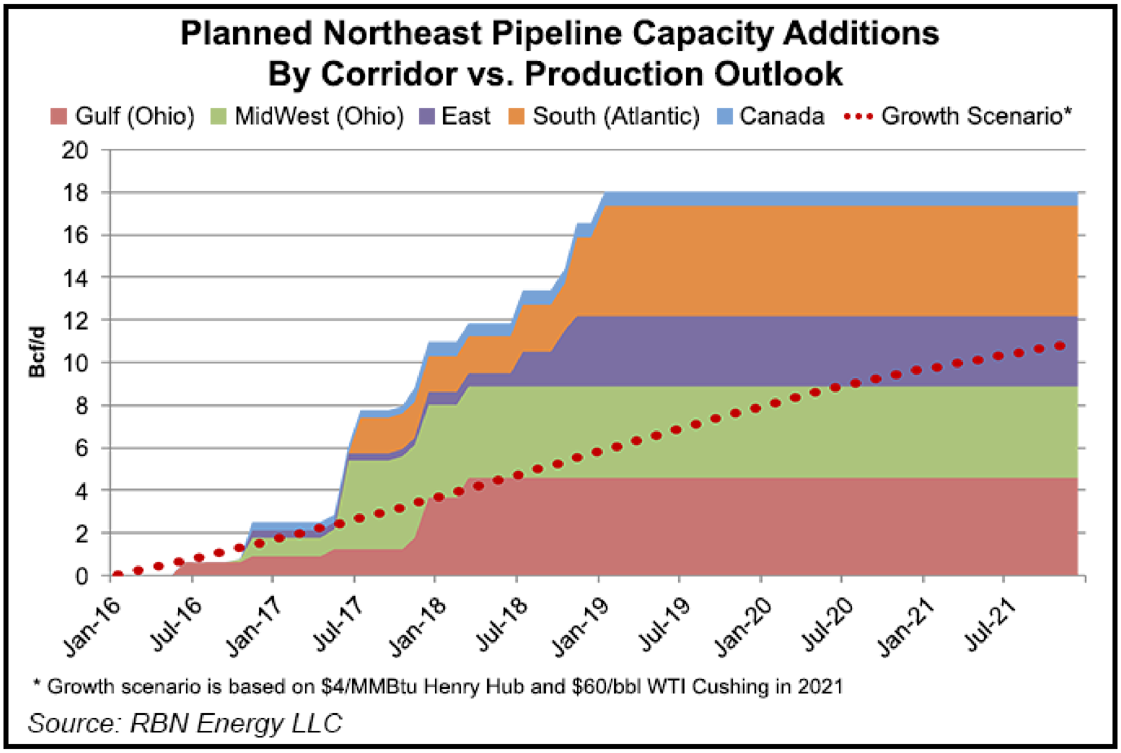
FERC is addressing this market inefficiency and in recent orders directed the industry, under the auspices of NAESB, to develop enhanced scheduling standards and services to "promote more efficient use of existing pipeline infrastructure and provide additional operational flexibility to all pipeline shippers [customers]." (FERC Order 809, *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, April 16, 2015). EDF is deeply engaged in these proceedings and in other ongoing refinements to increase capacity utilization. When pipelines are better utilized, pipeline customers and energy consumers can avoid costs for <u>some</u> new pipeline capacity.

In the recent Quadrennial Energy Review (QER, April 2015), the DOE summarized approaches to and the comparative costs for improving natural gas pipeline capacity and deliverability. In the first instance, the most inexpensive way to transport gas is by using existing infrastructure, noting that many pipelines have excess capacity. In cases where utilization of an existing pipeline network is high, DOE states that the next most cost effective solution is to add capacity to existing lines through increased compression and looping, noting that the more modern pipelines were designed so that compression could be increased in order to add capacity at low cost. Finally, DOE observes that where existing pipeline utilization is high and capacity utilization is maximized, the market-based underpinnings incent new capacity investment ("then the price differential between the two points on the network should increase and create an incentive for shippers to support midstream pipeline development in order to capture the arbitrage opportunity across the network." QER Appendix B at p. 29). It further observes that "the need for new pipelines is apparent in the Marcellus, where the largest amount of pipeline investment is expected to occur."

More recently, FERC assessed the extent and sufficiency of the ongoing pipeline buildout. In the State of the Markets 2015 Report (April 2016), FERC staff analysis concluded that in most of the country, "regional price differences across the country were not large, a sign that midstream investment over the past 10 years have largely relieved natural gas transportation constraints." An exception, according to FERC staff, is the Marcellus production area of the northeast and into New England, but that "new capacity additions should significantly relieve transportation constraints in these regions by 2019 if projects that are planned and under construction are approved and completed by the scheduled in-service dates."

In fact, there is reason to believe that more year-round capacity than is needed is currently under development to transport Marcellus gas.

Just last week, an experienced and respected gas industry veteran, RBN Energy LLC President Rusty Braziel, shared his analysis suggesting that currently planned takeaway capacity from the Marcellus is on the way to an "overbuild." According to Mr. Braziel, his firm estimated Northeast production through 2021 by taking a range of price scenarios and determining what producers would be likely to drill and how many drilled but uncompleted wells they would put into service. In RBN's most aggressive growth scenario, production would increase by 11 billion cubic feet per day (Bcf/d) over the next five years. Adding up all of the major proposed new pipeline projects, RBN calculated 18 Bcf/day of new takeaway capacity under development, resulting in excess capacity (illustrated below).




With the magnitude of new pipeline projects under development in addition to those deployed over the past 10 years, there are signs that a gas pipeline capacity bubble is forming. A capacity bubble could impose unnecessary costs on energy customers for expensive yet unneeded pipeline capacity, and ultimately constrain deployment of lower cost energy sources like wind and solar in the future considering the long financial lives and expense of new capacity. Where new pipeline capacity is financed by market participants <u>who choose to risk their capital to capture benefits</u>, the prospects of an overbuild are <u>not</u> particularly troublesome from the economic standpoint of society as a whole. However, a pipeline capacity build-out induced by policies designed to spread the costs of new infrastructure on captive retail gas or electric ratepayers will almost surely become un-economic, undermine market drivers for more efficient solutions and impose unacceptable long term environmental and economic costs.

Here's why. Pipelines are capital intensive and expensive. On a per unit (either per dekatherm or per million btu) basis, transportation costs for new greenfield capacity are almost as much as the current commodity price for natural gas.

Before a proposed new pipeline can apply for a FERC Certificate, it must execute contracts providing sufficient revenue from shippers to pay for the full cost of the project. Those costs include: construction, return on and of equity, depreciation, taxes, maintenance and operations. In these contracts (referred to as "precedent agreements"), pipeline customers ("shippers") agree to cover these costs through take-or-pay obligations whereby daily pipeline delivery capacity is reserved and paid for by shippers for every day over the term of the transportation service agreements -- whether or not those services are used. Because the cost of constructing a new pipeline (particularly a greenfield project) are so great, these contracts must be of long duration, typically 20 years. Normally, new pipelines are financed over 35 – 40 years in order to spread the costs so that per unit transportation services can be reasonably affordable.

Pipeline customers voluntarily enter take-or-pay contracts for "firm" transportation capacity over long periods of time when they determine that the cost of the new capacity is less than the price differential between the supply and their delivery points (referred to as the "basis differential"), thus capturing an arbitrage opportunity across a transportation network, as DOE points out (discussed above). In the natural gas transportation market, that basis differential disappears the day the new pipeline capacity comes into service, as the capacity provides a new delivery pathway between the two pricing points to eliminate the basis differential.

Shippers entering into long term agreements with capacity developers must have a high degree of confidence that the market conditions signaling the need for new pipeline capacity will persist for many years into the future. In the absence of a voluntary transaction between capacity developers and market participants risking their own capital, further capacity expansion would only occur in the event policymakers impose long term financial obligations on captive ratepayers for costly long-lived infrastructure. And should they do so, they are going outside of the price signals sent by a rational market. Any such government-induced incursion into the market is highly risky and if pursued, is likely to impose costs on the obligors in excess of putative benefits, while enriching those who benefit without them bearing risk in proportion to the investment.

As it stands, we are seeing a disturbing trend of utilities pursuing a capacity expansion strategy by imposing transportation contract costs on state-regulated retail utility ratepayers so that affiliates of those same utilities can earn shareholder returns as pipeline developers. In the last three years, a dozen or more utility holding companies have entered into affiliate transactions whereby the retail utility affiliate commits to new long term capacity with its pipeline developer affiliate. The essence of this financing structure is to take a cost pass-through for a retail gas or electric distribution utility –a contract for natural gas transportation services- and pay those transportation fees to an affiliated pipeline developer entitled to accrue return on its investment from that same revenue. Thus ratepayer costs which may not be justified by ratepayer demand are being converted into shareholder return.

In this testimony, EDF is not asking the committee to second guess the determinations of state Public Utility Commissions to approve such affiliate transportation agreements. We suggest though, that in the aggregate, ratepayer subsidization schemes along these lines are likely to induce new capacity deployment in excess of rational market outcomes, and therefore bear on the extent of need for and prospective benefits of further policy incursion at the federal level.

From EDF's vantage point, retail energy customers would benefit from policy refinements whereby FERC undertakes a more robust and detailed assessment of the extent and duration of market need for new interstate pipeline capacity by refining its longstanding pipeline permitting policy -which largely relies on the mere existence of transportation service contracts as sufficient evidence of market need. As we and others are pointing out to the Commission, the crux of the Commission's statutory duty in setting rates is to establish an equitable balance of risks and rewards as between pipeline ratepayers and pipeline shareholders. Any policy or outcome which imposes costs on captive ratepayers in a manner that provides disproportionate benefit to pipeline shareholders (or third party gas consumers) is suspect within the rubric of the Natural Gas Act's fundamental risk/reward balancing precepts.

Another issue for policy consideration, with major implications to capacity utilization and market price signals for new pipelines results from the current market design: increasingly there is a mismatch between the level and types of transportation services provided (and priced) by the pipelines versus the more flexible needs of their largest growth customer, electric power generation. Because pipeline revenue is heavily weighted towards the sale of capacity, pipelines have diminished commercial incentive to earn revenues by providing flexible delivery services (either by facilitating varying flow quantities or multiple delivery scheduling opportunities over the course of a day). Flexible delivery services, however, are the primary need of electric power generators, and becoming increasingly so in a more dynamic and renewable electric grid.

Under the standard contract form, virtually all transportation services are provided as "ratable" flows. Ratable flow means that when a shipper schedules deliveries with a pipeline, it must schedule hourly delivery of 1/24th of its contracted daily quantity every hour. In other words, the market design assumes that transportation customers want and will take a fixed level of flow over every hour of the day after making a scheduling request with a pipeline. While some pipelines provide enhanced delivery flexibility (such as "no-notice" scheduling allowing shippers to vary flows), the overwhelming majority (approximately 90%) of contracted transportation services require uniform hourly flow.

Electric power generation has grown from less than 15% of total pipeline flows in 2008 to 34% in 2015, and is forecasted to grow to 40% or more in the next five years. (EIA data, National Association of Manufacturers Nay 2016). But very few electric generators need steady flows of gas because the vast proportion of power plants do not run at the same level of output for every hour of the day. According to EIA data (January through November 2015, compiled by energy consultancy Skipping Stone) only 6% of natural gas-fired power plants operate at above an 80% load factor with the majority of output (68%) being generated by plants operating between a 50% and 80% load factor. Moreover, daily power production fluctuation is increasing as more renewable energy is deployed.

Going forward, we suggest that it is critical to reliable, efficient and cost-effective operation of the grid for pipelines to provide and price short-term (even within day) flexible delivery services, as natural gas-fired power generation continues to increase its market share.

We suggest that market rules should provide pipelines with some form of within-day pricing flexibility for non-ratable short-term services in order to start sending price signals for this type of service. Only through effective price formation for the value of flexible services, will the market see price signals and in turn channel investment to those willing to provide these fast response varying receipt and delivery services, either provided by pipelines or others.

Such price signals, along with those coming from basis differentials, will signal to the market the type of capacity services that are needed and will call forth the right mix. Without such price signals, neither the market nor policymakers will know with any certainty whether what is called for is more short-term flexibility or more costly long term year-round pipeline capacity. It may be that what is needed is better and higher utilization of storage, including gas, and/or electric (batteries), or price responsive demand response; or it may be more pipelines. Without such short-term services and the price signals they generate, market participants and regulators can't know.

What we do know is that for the first time in almost thirty five years, there are existing pipelines seeking rate relief from FERC because they are unable to generate sufficient contract revenue to cover operating costs plus entitled rates of return. The FERC filings of two sizeable pipeline networks seeking FERC approval to increase rates assert that production increases from new regions are altering flows away from and on different parts of their systems and these alterations negatively impact revenues to the pipeline systems. Notably, the filings also explicitly recognize that going forward, renewable energy sources like wind and solar "are likely to offer a viable competitive alternative to natural gas" particularly over the presumptive 35-40 year economic life of new pipeline capacity. (ANR Pipeline and Tallgrass Interstate Transmission System testimony before FERC).

The ANR and Tallgrass filings seek to impose large rate increases on "recourse" customers and provide a glimpse of an overbuilt future. EDF suggests that a rate design weighted to the value of services, more so than the cost of capacity, will provide more focused price signals for where, what amount and what types of new capacity are cost effective (both now and in the future).

## Methane Leaks: An Economic, Safety and Environmental Problem

An area of particular environmental concern to scientists and environmental groups is the problem of methane emissions from across the natural gas supply chain. Although it burns more cleanly than coal, un-combusted natural gas is mostly methane, a greenhouse gas 84 times more potent than carbon dioxide in the first 20 years after its release. As natural gas production and use continue to expand, methane emissions threaten to cancel out the climate benefits that natural gas proponents often claim, especially with regard to the growing share of electricity generation fueled by gas.

According to EPA's most recent greenhouse gas emissions inventory (1990 through 2014, released April 15, 2016), the oil and gas sector represents 33% of U.S. methane emissions, the largest of all U.S. sources. My scientist colleagues at EDF are in the midst of completing the most comprehensive assessment of methane emissions from the oil and gas sector thus far through 16 studies conducted with academic experts and in collaboration with dozens of oil and gas market participants.

One of these studies, conducted by researchers at Colorado State University, conclude that emissions from the gathering system amount to 30% of total emissions. (Marchese et al, ES&T 2015). According to this study, facilities that collect and gather natural gas from well sites across the United States emit about one hundred billion cubic feet of natural gas a year, roughly eight times the previous estimates by the EPA for the segment. The wasted gas identified in the study is worth about $300 million, and packs the same 20-year climate impact as 37 coal-fired power plants. Currently, these gathering facilities are largely unregulated; in the vast majority of the system, leak abatement and safety management are dependent on voluntary measures by individual operators.

In the transmission and storage segment, another study in our series of 16 estimated annual emissions of about 80 billion cubic feet per year escaping from thousands of key nodes along the nation's natural gas interstate pipeline system. This equals the 20-year climate impact of 33 coal-fired power plants and more than $240 million worth of wasted natural gas per year.

The estimated storage emissions, however, do not include emissions from well failures like the recent Aliso Canyon disaster in California which released nearly 100,000 tons of methane. Operators aren't required to report the amount leaked to regulators – nor is there currently a method for EPA to consider these emissions in their official estimates. Aliso Canyon is a glaring example of the public health, safety, environmental and economic consequences when oversight of expanding mid-stream infrastructure is left to largely voluntary measures, and research shows similar problems occurring regularly on a smaller scale throughout the supply chain.

In addition to adverse climate and public safety impacts, methane emissions from gathering, processing, transmission and storage infrastructure waste a valuable resource paid for, more often than not, by natural gas consumers rather than infrastructure operators. The cost of lost and unaccounted for gas, which includes but is not analogous to leaked gas, is borne by shippers (i.e., customers) in the interstate pipeline system, and by retail ratepayers in the natural gas utility distribution network.

While research about methane emissions is ongoing, we already know that there is much that can and should be done. A cost analysis performed by experts at ICF, International – based on data from industry -- found a striking opportunity for achieving dramatic reductions in methane emissions from the oil and gas sector, including in the equipment being used by midstream operators. The study revealed that a 40% reduction in methane emissions from the sector could be achieved over the next five years at a cost of less than 1 penny per thousand cubic feet of gas produced. Low-cost reductions of this magnitude would go a long way toward ensuring that the expansion of natural gas infrastructure and supply will not be a net loss for the environment.

Moreover, according to ICF, methane emissions reductions at this scale can be achieved using current technology. That is, most if not all, of the equipment and operational improvements needed to provide meaningful emissions reductions can already be found in the market. Accordingly, in any discussion about the need, means, or opportunities for reducing methane emissions from the supply chain, there need be no debate about whether the equipment exists to get the job done. It does, and it is cost-effective to use.

From EDF's standpoint, it is necessary and appropriate for EPA and the Department of Transportation to advance ongoing regulatory initiatives to prevent future Aliso Canyon type incidents and to require cost-effective reductions in methane emissions from the midstream segment. It is critical to the propriety of natural gas, as an increasingly important fuel in the US energy system, for these efforts to continue to fruition.

Thank you for the opportunity to present our ongoing science and policy advocacy which is designed and intended to ensure that natural gas infrastructure is deployed and used in a manner that broadly advances economic, public safety and environmental interests.