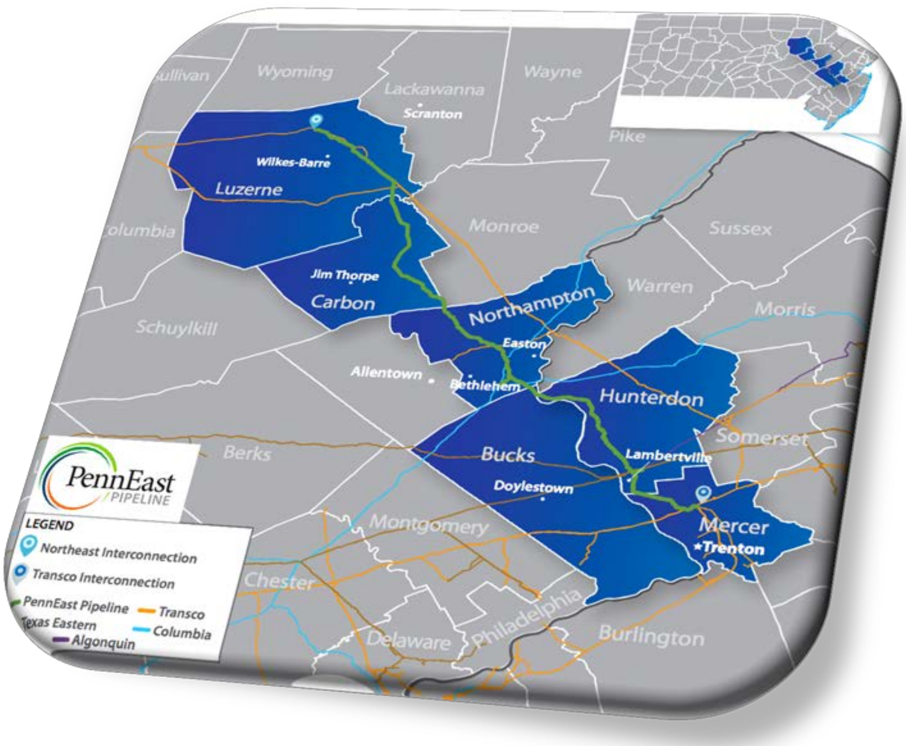
Analysis of Public Benefit Regarding PennEast Pipeline



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For

The New Jersey Conservation Foundation

SkippingStone

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About Skipping Stone
Skipping Stone is an energy markets consulting firm that helps clients navigate market changes, capitalize on opportunities and manage business risks. Our services include market assessment, strategy development, strategy implementation, managed business services and talent management. Market sector focus areas are natural gas and power markets, renewable energy, demand response, energy technology and energy management. Skipping Stone's model of deploying only energy industry veterans has delivered measurable bottom-line results for over 270 clients globally.

Skipping Stone operates Capacity Center which is a proprietary technology platform and data center that is the only all-in-one Capacity Release and Operational Notice information source synced with the Interstate pipeline system. Our database not only collects the data as it occurs, it is a storehouse of historical Capacity Release transactions since 1994. We also track shipper entity status and the pipeline receipt and/or delivery points, flows and capacity. Our analysts and consultants have years of experience working in natural gas markets. Capacity Center has worked with over a hundred clients on a wide variety of natural gas market and pipeline related reports and projects.

Headquartered in Boston, the firm has offices in Atlanta, Houston, Los Angeles, Tokyo and London. For more information, visit [www.SkippingStone.com.](http://www.SkippingStone.com)

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Executive Summary

In evaluating the PennEast application, FERC Commissioners will seek to determine whether the application to build new pipeline capacity provides evidence of public benefit. This study evaluates a central claim in the application – that PennEast will lower costs to consumers. This analysis also examines unserved demand for firm capacity and evaluates two alternatives for meeting peak demand needs of electric generation customers, thereby ensuring reliability of electric generation.

Our major conclusions are as follows:

1. **Local gas distribution companies in the Eastern Pennsylvania and New Jersey market have more than enough firm capacity to meet the needs of customers during peak winter periods.** Our analysis shows there is currently *49.9% more capacity than needed to meet even the harsh winter experienced in 2013 (the Polar Vortex Winter)[1].*

2. **Providers of gas-fired electric generation can meet their need for electric reliability more cost-effectively by using either dual fuel or natural gas from LNG facilities.**

   Natural gas pipelines are typically fully utilized between 10 and 30 days a year. Building a pipeline that is only fully utilized for a short period of time is not a cost-effective way to provide reliable electricity. Electric generation customers prefer to purchase supplies using interruptible contracts[2], knowing that they may not be able to obtain gas supplies during peak demand periods. Under pressure to improve electric reliability, such customers now have to choose between contracting for firm supply from new pipeline capacity, such as PennEast, or choose an alternative to natural gas. A common alternative is to switch to oil-fired generation when natural gas is not available; a second is to purchase natural gas from LNG facilities.

   Based on our analysis of alternative costs, an electric generator would bear a higher fixed cost burden by choosing to meet peak demand through firm pipeline capacity and would be economically better off choosing oil or LNG for the few days each year of high electric demand.

3. **PennEast will add significant excess capacity to the market in Eastern Pennsylvania and New Jersey.** Shippers representing almost 40% of capacity stated in the application that they intend to shift their gas supplies from existing competitor pipelines to PennEast, leaving excess and unutilized capacity on other pipelines.

4. **The impact of PennEast may well be to increase, rather than decrease, costs to gas customers. Analysis shows that rate-paying consumers of local gas distribution companies (LDCs) bear the greatest risk of increased costs regardless of whether they are on PennEast or competing pipelines.** Customers of the LDC shippers subscribing to PennEast will pay the full cost of annual service for only

[1] Concentric Energy Advisors' (Concentric) report for PennEast used peak sendout figures for this period.
[2] Interruptible transportation contracts are contracts under which no fixed charges are incurred, rather charges are only incurred when and to the extent the contract is actually used to deliver gas.

a few days of effective usage per year. Customers served by LDCs on competing pipelines are likely to suffer financial losses in two ways. First, as PennEast adds 1 billion cubic feet per day of capacity to the market, the value of existing capacity in the secondary market will collapse, shrinking by as much as 50 to 90%. Our analysis of transactions on two competitor pipelines shows that the loss of benefit to ratepayers, just on those two pipelines, could be between $130 to $230 million each year. Second, as customers shift contracts from existing pipelines to PennEast, FERC rules permit those pipelines to file for rate increases on remaining customers to recover lost revenues. Resulting rate increases could expose ratepayers to additional costs of over $50 million per year – just on these two pipelines.

5. **PennEast claims of potential savings for gas consumers or electric generation customers are based on faulty assumptions and analysis.** The price spike experienced during the Polar Vortex is unlikely to be repeated and does not alone justify the addition of new pipeline capacity. PennEast claimed benefits that are not based upon future projections of gas prices and do not take into account 8.1 billion cubic feet per day of infrastructure scheduled to ramp up in 2017. PennEast does not address evidence that similar price spikes did not occur in Winter 2014/2015 or the introduction by PJM and NEISO of important Supply Assurance Programs that reduce dependence on constrained natural gas pipelines during peak demand periods.
6. **FERC should not rely on non-arms-length transactions as a foundation for finding market need.** Owners of PennEast contracted for 74.2% of total capacity. FERC Commissioners have a special responsibility to protect rate-paying customers. For PennEast, 38.9% of the capacity is held by local gas distribution companies whose parent firms will benefit from their ownership of PennEast, and whose customers – rate-payers – are at risk of paying for unneeded capacity for 15 years.
7. **In the case of PennEast, the precedent contracts signed by local distribution companies are not arm's length and should not be relied upon for a finding of public convenience and necessity.**
8. **The Commission should institute a full evidentiary proceeding with discovery and cross-examination to determine what demand is being met by the proposed pipeline and whether less disruptive and more cost effective alternatives exist to meet such demand.**

Section I – Study Overview

Skipping Stone was asked to review the proposed PennEast Pipeline and provide its opinion of the potential utilization of the incremental capacity into the geographic region, and what that might mean for electric generation customers. Understanding that the choice faced by electric generation firms would require an analysis of the cost and benefits of purchasing firm capacity on a new pipeline compared to other options, we also provide indicative cost-benefit analyses of two alternatives. Skipping Stone was also asked to examine possible financial motivations of the Sponsor/Shippers of PennEast as an alternative explanation for the purpose of the project.

This review is based on our examination of documents from the PennEast Pipeline LLC FERC Certificate Application CP15-558 and publicly available natural gas industry data and documents.

The application makes a number of assertions about the project purpose as follows:

> "to bring lower cost natural gas produced in the Marcellus Shale region in eastern Pennsylvania to homes and businesses in New Jersey, Pennsylvania, New York and surrounding states."
>
> "…with the additional pipeline capacity, energy consumers throughout eastern Pennsylvania and New Jersey would have realized over $890 million in reduced energy costs in the winter of 2013-2014…. Further, without additional natural gas infrastructure providing the region increased access to the abundant dry natural gas reserves located in the eastern Pennsylvania production area, similar price spikes and correspondingly, the potential savings offered by the PennEast Project, could be anticipated in the future. Thus, the PennEast Project is expected to bring annual energy cost savings and significant economic benefits to the Pennsylvania and New Jersey economies."

The assertion that PennEast will produce <u>annual energy cost savings</u> requires looking at a number of salient factors, including:

1) What is the demand that PennEast is purporting to serve, is there unmet demand for year-round, firm capacity in the subject region, and related to that, what would be the utilization rate of such incremental capacity into the subject market.[3] And at such utilization rate, what would be the effective per-unit cost of such incremental capacity at indicative utilizations?
2) Is firm, year-round capacity a cost-effective solution to meet electric generation customers' needs during peak winter periods?
3) What might be offsetting costs to any potential savings?

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[3] In this regard, Skipping Stone assumes that the utilization rates of other lines serving the subject market are or remain the same and that utilization of the PennEast line comes from displacement of peak-shaving resources and electric generation. Even if PennEast were to be higher utilized than the estimated utilizations used in this memorandum, such higher utilization of PennEast would come at the expense of utilization of other pipelines serving the market. Thus, for economic analysis of the effective per unit cost of the added capacity, Skipping Stone assumes for these purposes that in the aggregate, PennEast would serve load unmet by existing natural gas pipelines (i.e., load met by LNG, or oil-fired electric generation).

4) Are the potential savings predicated on repeats of unusual circumstances?
5) Have there been developments in electric and gas markets subsequent to the filing of the PennEast application which undermine the assumptions that must be made in order for there to be future savings associated with the incremental capacity proposed to be provided by PennEast?
6) In light of potentially questionable demand, what financial motives might underpin the Sponsor/Shippers' decision to seek permission to construct a new natural gas pipeline.

Section II – Unserved Demand for Pipeline Capacity and Analysis of Cost-Effective Alternatives

Can LDCs Meet Needs for Firm Pipeline Capacity?

To evaluate whether current pipeline capacity is sufficient to meet current and future demand from LDCs and other customers requiring firm capacity in the Eastern PA, NJ region, it is important to identify the Peak Day demand from LDCs in the region and compare it to Total Peak Day Resources available in the region. The Concentric Energy Advisors report, sponsored by PennEast, fails to examine actual pipeline contracts and available resources to meet peak demand in determining whether PennEast is, in fact, needed to meet peak demand.

We utilized information provided by Concentric about LDC demand in the region from Table 2: "Eastern Pennsylvania and New Jersey LDC Summary Operating Statistics."[4] Information for each LDC is reproduced below in Table 1 as columns (a), (b), (c), and (d) representing Local Distribution Companies (LDCs), Number of Natural Gas Customers, 2013 Retail Sales Volumes (Mcf) and Peak Day Sendout (Mcf), respectively.

To properly calculate current Peak Day Resources it is important to include not only LDC held pipeline capacity and LNG sendout capability, but to also include winter pipeline subscribed capacity levels of retailers[5] serving load in eastern PA and NJ, end-users and electric generators with contracts to locations in the same geographic area[6] and capacity held by producer marketers into this same geographic area[7]. Rows 13 and 14 provide the contracted winter pipeline capacity for these two categories of pipeline capacity holders. For both

[4] Sources: EIA Form 176, Annual 1307(f) Filing materials, State LDC Filings, and information provided by LDCs.
[5] Here, retailers are those marketers that explicitly serve residential and commercial load in the geographic area and have pipeline FT contracts with firm primary delivery points in the subject geographic area. Note these entities can be distinguished from wholesale Producer-Marketers because these retailer entities in these markets and others have capacity releases from LDCs that carry the indicator that they are serving retail load under one or another "retail choice programs" of LDCs.
[6] With respect to electric generators' capacity, Skipping Stone excluded subscribed winter pipeline capacity level contracts that were for lateral capacity only as these lateral capacity(ies) only entitle the electric generators to move gas under these agreements from one end of the lateral to another.
[7] This type of capacity contract is often referred to as "producer-push" capacity where the capacity comes into the geographic area often (but not always) to pooling points from which it can be purchased for delivery to actual delivery locations within the geographic area.

categories, note that capacity held by shippers to New York points or to pipelines leaving New Jersey, such as Algonquin, was excluded.

We include additional information in columns (e)[8], (f) and (g).

- Column (e) shows these same entities' 2015 Contracted Winter Pipeline Capacity levels in their eastern PA and NJ service locations[9]
- Column (f) provides publicly available LNG vaporization capacity in the same geographic area (including proposed) and
- Column (g) shows Total Peak Day Resources (which is the total of columns (e) and (f))[10]

Table 1. Analysis of LDC Demand in Eastern Pennsylvania and New Jersey

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		No. of Natural Gas Customers	2013 Retail Sales Volumes (Mcf)	Peak Day Sendout (Mcf)	2015 Contracted Winter Pipeline Capacity	2015 LNG Vaporization (Mcf)	2015 Total Peak Day Resources
	Eastern Pennsylvania						
1	UGI Utilities	357,408	116,675,523	654,050	494,607	202,500	697,107
2	UGI Penn	163,796	56,733,872	416,488	218,490	0	218,490
3	PGW	498,694	73,229,988	616,000	304,892	225,000	529,892
4	PECO	498,843	85,834,449	759,594	551,834	161,700	713,534
5	Subtotal	1,518,741	332,473,832	2,446,132	1,569,823	589,200	2,159,023
	New Jersey						
6	PSEG	1,790,240	453,524,804	2,973,000	1,894,994	64,000	1,958,994
7	NJNG	501,595	67,616,570	690,415	525,604	170,000	695,604
8	SJG	359,732	58,997,922	495,056	404,871	75,000	479,871
9	SJR Proposed					250,000	250,000
10	Elizabethtown	278,871	52,732,119	440,148	302,435	24,000	326,435
11	Subtotal	2,930,438	632,871,415	4,598,619	3,127,904	583,000	3,710,904
12	Concentric Regional Total	4,449,179	965,345,247	7,044,751			
13	Retailers, End-Users & Power Gen w- Eastern PA & NJ Capacity				940,095	0	940,095
14	Producer/Marketers w-Eastern PA & NJ Capacity				3,748,500	0	3,748,500
15	Regional Totals			7,044,751	9,386,322	1,172,200	10,558,522

8 Skipping Stone used 2015 Winter Contracted Capacity because this is the level of capacity to which the PennEast capacity is additive. In addition, it represents the level of capacity that exists (and would exist) absent PennEast and that would be utilized to meet repetitive peak send-outs of the magnitude of those experienced in 2013.

9 Note that Skipping Stone excluded from such subscribed winter pipeline capacity level contracts that were for lateral capacity only as these lateral capacity(ies) do not entitle the entity(ies) to receive more gas but rather are means of moving gas under these agreements from one end of the lateral to another.

10 Note that Skipping Stone did not include propane-air resources of any of the entities in the Total of Peak Day Resources.

The above analysis shows that currently subscribed pipeline capacity alone exceeds the Concentric identified entities' peak day sendout by over 33% (Line 15 column (e) divided by Line 15 column (d)). Including these entities' LNG resources increases deliverability resources to 10,558,522 (Mcf per day). The purpose of LNG resources is to provide a local distribution company with additional supplies during peak demand periods that are more cost-effective than the purchase of additional firm pipeline capacity. In total, there are 49.9% more resources available to meet peak day demand from local gas distribution companies in the region than is needed, according to Concentric's own demand data (Line 15 column (g) divided by Line 15 column (d)).

If PennEast is not needed to supply the needs of LDCs in the region, then is the additional supply of 1 billion cubic feet per day of pipeline capacity actually necessary, and for what purpose?

Is Firm Pipeline Capacity Cost-Effective for Electric Generation Customers?

The Concentric study analyzes demand for electric generation, which is typically provided either by contracts for interruptible capacity or by means of bundled (transportation capacity and gas) sales at the generators' delivery points out of the gas network[11], rather than by generator-held contracts with pipelines for firm capacity. That said, the report nevertheless argues that additional capacity is needed for electric generation and to prevent "price spikes."

The period of greatest demand for natural gas is that period of "coincident demand," when gas demand for home heating (provided by LDCs) and for electric generation are both high. In the eastern PA, NJ region coincident demand occurs during winter cold spells. If the demand that PennEast might serve is the coincident demand of natural gas for heating and electric generation in the winter-period, then one has to ask two related questions:

- What is the duration of this coincident demand?
- What is the most economical means of meeting such coincident demand?

Recent studies by EISPC, ICF, ENERGYZT and Skipping Stone[12] have all identified that the period of this coincident demand is from 10 to 30 days, and may increase to 45 days by 2020 and 60 days by 2030. The following analysis calculates the cost of capacity for 10, 20 and 30 days, and includes calculations for 45 and 60 days for completeness.

Is Dual Fuel a Cost-Effective Alternative?

To assess the most economical means of meeting this very short period of peak-period coincident demand, we compare the costs of relying on firm pipeline capacity with a well-known alternative, the use of dual fuel for electric generation. First, we calculate the cost of providing

[11] These delivery points out of the gas network are either at direct-to-plant pipeline points or are points on LDC systems where the generator can receive gas from the LDC.

[12] EISPC "Study on Long-Term Electric and Natural Gas Infrastructure Requirements in the Eastern Interconnection" September 2014
ICF "Options for Serving New England Natural Gas Demand October 22, 2013
ENERGYZT "Analysis of Winter Reliability Solutions for New England Energy Markets August 2015
Skipping Stone "Solving New England's Gas Deliverability Problem using LNG Storage and Market Incentives" September, 2015

pipeline capacity that is fully utilized only between 10 and 60 days per year. We then compare this cost with the equivalent cost of using fuel oil rather than natural gas. This analysis also assumes that because the pipelines in the subject geographic area are fully subscribed from their production locations to their market locations, then electric generation customers, to get such capacity for natural gas during coincident peak demand days, would require incremental firm pipeline capacity that cannot be interrupted during such periods of peak demand.

The all-in cost is the effective cost to a power generator reserving capacity year-round[13] that is only needed from 10 to 60 days per year[14]. To illustrate, Skipping Stone provides the analysis shown in Table 2. This analysis is based on two assumptions that can be adjusted: The 100% Load Factor Pipeline Cost (assumed to be $.50/Dth/Day); and the Winter Gas Cost (using the estimated 2019/2020 winter gas cost published by NYMEX in Feb-2016).

Table 2. Analysis of All-in Cost of Capacity

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
100% Load Factor Pipeline Cost	Days Per Yr	Annual Cost/Dth /Day of Capacity	Equivalent Days of 100% load Factor Use /Yr	Cost of Pipeline Capacity per Dth used	Winter Gas Cost	All-in Delivered Cost per Dth used	Dth/Gal	Equivalent $/Gal
$0.43	365	$156.95	10	$15.70	$2.90	$18.60	0.139	$2.58
$0.43	365	$156.95	20	$7.85	$2.90	$10.75	0.139	$1.49
$0.43	365	$156.95	30	$5.23	$2.90	$8.13	0.139	$1.13
$0.43	365	$156.95	45	$3.49	$2.90	$6.39	0.139	$0.89
$0.43	365	$156.95	60	$2.62	$2.90	$5.52	0.139	$0.77

Calculation of All-in Comparative Costs for Fuel Oil

How does the total cost of using natural gas to meet peak load, available only through year-round firm capacity, compare with the cost of using No.2 fuel oil?

First, we evaluate the cost of contracting for firm pipeline capacity for a given number of peak days. Column (c) shows the annualized cost per Dth per day of capacity[15]. Column (d) varies

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[13] This same all-in cost calculation would also apply to an LDC displacing some amount of LNG vaporization capacity with year-round pipeline capacity. This occurs when the LNG vaporization and LNG storage capacity is utilized to an extent such that it makes economic sense to add an increment of pipeline capacity and then “grow into” that pipeline capacity again relying on LNG for needle peaks until overall load growth and winter period demand once again makes anther incremental pipeline capacity addition economical..

[14] The reason that such capacity may only be needed by a power generator from 10 to 60 days per year is that there is sufficient otherwise un-used existing capacity all but those days when the coincident demand from electric generation and heating load exceeds existing pipeline capacity. See also Concentric report Page 18 where it discusses price spikes when demand is greater than 8 Bcf/d into the subject market which according to Figure 11 on page 17 occurred some 15 times during the Polar Vortex winter of 2013/2014.

[15] The annual cost per Dth per day presents what the cost for one Dth on one day would be if one Dth per day of capacity was reserved for a year and only used on one day to receive the one Dth.

the number of equivalent days of 100% load factor, or days of peak usage. Ten days of full use is equivalent to 5 days of full use and 10 days of 50% use. The all-in cost of capacity per Dth (assuming a cost of $0.43 per Dth per day of reservation and 10 days of use during times of peak load) has an effective capacity cost of $15.70 per Dth used. At 30 days of peak load, the all-in capacity cost drops to $5.23. To calculate the all-in cost of use, we add the cost of gas during the winter period, $2.90 per Dth, for a total delivered fuel cost of $18.60 per Dth used.

Column (i) shows the price per gallon for fuel that results in an equivalent cost per Dth for the natural gas alternative. For peak demand of 10 days, the natural gas alternative would be the lower cost alternative if the cost of No.2 fuel oil is $2.58 per gallon or higher, equivalent to $108.56 per barrel of oil. For peak demand of 30 days, the natural gas alternative would be the lower cost alternative if the cost of No.2 fuel oil is $1.13, equivalent to $47.47 per barrel of oil.

It should be noted that this 10 to 60 days of peak demand analysis is for illustrative purposes to show that even a pipeline that has a daily transportation rate of as little as 43 cents can result in very high effective costs in use unless it is utilized much more than 60 days – i.e., the existing gas system is constrained on that many or more days.

Based on this basic analysis of alternative costs, one can readily see that it is highly unlikely that a generator will choose to bear the fixed cost burden of the pipeline capacity and would be economically better off choosing oil as fuel during the few days of coincident demand each year.

Calculation of All-in Comparative Costs for LNG

In addition to the oil alternative, securing additional LNG deliveries at locations downstream (i.e., north and east) of the NJ/PA demand centers, as well as from existing LNG facilities within the NJ/PA geographic area cited by the Concentric report, are likely to be even less expensive as a supply alternative. Of note here, any additional LNG that is vaporized at Northeast LNG facilities, such as Eastern MA or New Brunswick, Canada, can make supplies traveling to the Northeast on various pipelines available instead for delivery into the NJ/PA region. This is because the LNG resources would physically serve the New England market thereby enabling supplies otherwise bound for New England to remain in the NJ/PA market and serve demand there. As a result, additional capacity would become available on one or more of the major pipelines connecting the NJ/PA demand centers to New England, such as Texas Eastern, Transco, Tennessee or Columbia to Algonquin (or Maritimes and Northeast).

Because of the current substantial excess of worldwide LNG, future LNG supplies are currently priced at $6.00 to $8.00 per Dth vaporized into New England markets. At these prices, LNG supplies are likely to clear the market lower than the above modeled oil prices in Table 2. Customers can arrange LNG supplies in advance of the winter period and ensure that the inventory is either in the LNG tanks or on the floating storage and regasification ships during the winter period. LNG inventory is arranged in advance in much the same way as pipeline capacity is reserved in advance, except subscription terms are typically year to year and for use of existing facilities do not require multi-year commitments.

Section III – Potential for Increased Costs to Captive Customers on Competing Pipelines

The FERC Commissioners are concerned with protecting consumers from excessive rates. We analyzed the potential impact of additional capacity on captive customers of competing pipelines with particular regard for the likely impact on rate-payers. Shippers who own capacity on competing pipelines are likely to suffer two negative impacts, or offsetting costs, as a direct result of the addition of the substantial 1 Billion cubic feet per day incremental capacity proposed by PennEast.

Shippers will encounter two sources of increased costs:

1) As the total supply of capacity increases, the value of secondary market capacity is likely to decline, particularly if demand is largely unchanged over the vast majority of the year (i.e., all but the highest 10 – 60 demand days per year).[16] Thus, shippers who own existing pipeline capacity and seek to resell unused capacity into the secondary capacity market **will suffer a loss of value**.

2) Non-renewal or turnback of subscriptions on existing lines could lead to cost-shifting to captive customers of such lines at the next rate case. The risk of non-renewal is significant, as several PennEast Shippers stated in the PennEast application that they plan not to renew portions(s) of their existing legacy capacity portfolios. In addition, other shippers may find that they are able to rely on excess capacity as a consequence of the addition to the market of the PennEast capacity and also choose to not renew. The revenue lost from such turnbacks will ultimately be re-distributed to the pipelines' remaining shippers.

What is the Impact of PennEast on Secondary Market Capacity Values?

Since there is no evidence of significant increased demand for the 40% of capacity purchased for in-state New Jersey use, the increased supply from PennEast will add to the total supply of pipeline capacity in the region and lead to significant underutilized capacity.

The secondary market enables shippers to find buyers for their unneeded capacity by means of either capacity release transactions and/or Asset Management Agreements[17] (AMAs). As a result of excess capacity, secondary market values related to capacity release and AMAs could drop dramatically.

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[16] The reductions in secondary market values impact any firm capacity holder with a less than 100% load factor use of their capacity which sells their unused capacity to others during period of low use. These secondary market purchasers pay the capacity holder for their firm rights. To the extent a particular geographic area is flooded with new capacity, the secondary market values drop to near zero because the supply greatly exceeds the demand. Specifically, it is generally LDCs that sell unused capacity and use large percentages (usually 80% or more) of these secondary market revenues to reduce rates paid by their firm sales customers (ex. residential and commercial customers).

[17] Asset Management Agreements are agreements where a purchaser agrees to provide capacity management services (and often gas supply) and pay the holder of firm capacity often large sums of money to gain control of their capacity in return for agreeing to use a limited amount of that capacity to meet the needs of the selling party while using the balance to make other sales to other parties. These AMAs are effectuated through capacity release transactions in the secondary market.

In particular, for the purposes of this memorandum, Skipping Stone studied capacity release transactions[18] on two pipelines in the subject geographic area: Texas Eastern Transmission (TETCO) and Transcontinental Gas Pipe Line (Transco). The period studied was 2015. The transactions analyzed were those where the capacity terminated in the same eastern PA and NJ geographic area as that discussed in the Concentric study for PennEast.

Skipping Stone found for these two pipelines that the value of traded capacity was in excess of $250 Million in 2015. The aggregated dollars, quantities and average rates for the two lines' 2015 transactions are set forth in the two tables that follow.

Table 3. Texas Eastern (TETCO) Traded Capacity[19]

TETCO 2015 Capacity Release Quantities, Rates and Value			
Eastern PA and NJ locations	**Annualized Daily Equivalent Traded (Dth)**	**Avg Rate per Dth/Day**	**Dollars Realized 2015**
From M2 and into M3	1,398,127	$0.3415	$174,292,476

[18] The transaction types studied were releases from capacity holders to acquiring shippers that were done outside of those done to enable retail choice. Under retail choice many LDCs release capacity at pipeline maximum rates (regardless of capacity values) to marketers that have contracted to serve firm customers on the LDCs' systems. These transactions do not reflect competitive pipeline capacity market conditions and therefore were eliminated so as not to overstate the value of released capacity in the subject markets. In addition, in those cases where no price was provided under an AMA transaction, the average price for the similar capacity was used.

[19] TETCO presents the values of their trades on a segment and point basis so Skipping Stone provided just the segment values (i.e., the values of capacity to get gas into M3 which is the eastern PA and NJ zone from the adjacent M2 area which is the western PA and OH zone) as those would be the values most impacted by an incremental 1 Billion Cubic feet (1,000,000 Dth/d) of capacity into their M3 zone serving eastern PA and NJ. Transco on the other hand reports the values for their trades on a point-to-point basis so the value of getting to a market area point from supply areas is that which would be impacted.

Table 4. Transcontinental Gas Pipe Line (Transco) Traded Capacity

Transco 2015 Capacity Release Quantities, Rates and Value				
ST	County of Delivery	Annualized Daily Equivalent Traded (Dth)	Avg Rate per Dth/Day	Dollars Realized 2015
NJ	Camden	2,000	$0.3050	$222,650
NJ	Essex	215,924	$0.1761	$13,879,181
NJ	Gloucester	104,589	$0.1430	$5,459,521
NJ	Mercer	208,184	$0.3453	$26,238,007
NJ	Middlesex	264,000	$0.2130	$20,524,680
NJ	Union	1,274	$0.0200	$9,300
PA	Monroe	152,459	$0.2553	$14,204,015
PA	Montgomery	167,962	$0.1135	$6,958,227
PA	Philadelphia	42,691	$0.1683	$2,622,767
Totals and Average		1,159,083	$0.2130	$90,118,348

Within the subject market area, the Annualized Daily Equivalent Traded[20] quantity on the two pipelines was approximately 2.55 Billion cubic feet per day. The impact of adding another 1 Billion cubic feet to the same market, an amount roughly equivalent to a 40% increase in regional capacity, would likely crush these values; potentially by as much as 50-90% depending on time of year and other factors. Thus, the PennEast pipeline is likely to put at risk the value of existing capacity, which recently traded for $260 Million per year in secondary market transactions. The greatest volume of existing capacity is held by local gas distribution companies, and ratepayers receive 80% of the value of such resale transactions. These ratepayers are captive customers of the LDCs served by existing pipelines and would suffer a significant financial loss if excess capacity were to be approved by FERC Commissioners.

Notably, this loss of benefit to ratepayers in the subject market would be experienced every year and we estimate could be between $130 Million and $230 Million, or averaging $180 Million each year until such time as the regional demand increase sufficiently to make use of the incremental capacity.

What is the Impact of Non-Renewals of Subscribed Capacity on other Pipelines?

With the addition of the incremental capacity associated with PennEast into the subject market, shippers with contracts expiring in the near to medium term (3 to 10 years from now) would be able to either forgo renewal and rely on the existence of the capacity or be able to negotiate substantial discounts.

[20] Annualized equivalent means if there were two trades, one of 1,000 Dth/d for a year and another for 365,000 Dth/d for a day, the Annualized Daily Equivalent of each would be 1,000 Dth/d and the total of the two would be 2,000 Dth/d.

We evaluate the potential impact of non-renewals on customers of Texas Eastern (TETCO) and Transco pipelines. The rates on TETCO and Transco for capacity to Eastern PA and NJ run on average between $0.52 and $0.67 per Dth/day. To illustrate, we calculated the impact if half of PennEast capacity, or 500,000 Dth/d, were to go unsubscribed on existing pipelines. At the average of the two rates above (~$0.595), the result would be a loss of over $108 Million per year between the two pipelines.

FERC rules permit affected pipelines to file for rate increases on remaining customers to seek to recover lost revenues. This could mean that the same ratepayers facing a potential loss of secondary market benefits could see a substantial portion of the costs of a rate increase as well. Moreover, like the cost of lost secondary market benefit, the cost of increased rates would be a cost they would bear every year.

Even if Pennsylvania and New Jersey ratepayers were forced to absorb **only half** of the potential lost revenues of $108 Million, this conservative estimate shows that ratepayers could be asked to pay an additional $50 Million a year.

Section IV – Factors that Diminish Possible Future Savings Suggested by Concentric

Are Potential Savings Due to a Repeat of Polar Vortex Circumstances Likely?

Concentric cites the 2013/2014 market disruptions coincident with the Polar Vortex as a measure of savings that could have been realized had PennEast been in service at that time.

Concentric appears to be justifying the build of a pipeline purely on the basis of a past price experience, one that notably did not occur in either the 2014/2015[21] nor in prior winters. So, the likelihood of reoccurrence is lower than assumed by Concentric. Concentric should, in any case, reduce their estimate of "potential savings" based on the likelihood of a reoccurrence of the conditions that would create such savings.

Furthermore, any calculation of potential savings should also include potential additional costs that would be borne by ratepayers holding capacity on competing pipelines. The costs, as calculated above, could range from $180 to $280 Million a year (averaging possibly $230 Million a year).

In addition, potential savings are reduced or even wholly eliminated as additional pipeline capacity comes online. Several other projects are slated to come on line before or around the same time as PennEast might come on line. If this occurs, the price depression facing producers with trapped gas supplies will largely be or have been abated. As recently reported by Barclays Bank[22], "Almost 8.1 Bcf/d of infrastructure in the Northeast region has been fully subscribed and is scheduled to ramp up in 2017." Barclays goes on to state "[m]ost of the 2017 pipeline projects are in the southwestern portion of the Marcellus and Utica shales[23], which potentially could strengthen price points," meaning that once the trapped production has outlet to market, the currently favorable pricing will dissipate, if not fully evaporate.

Pipelines should be planned to address longer-term conditions and trends, rather than as a response to a single event, since planning and construction of pipeline capacity takes several years. In order to have been in service by the winter of 2013 PennEast would have had to have started its development process somewhere around the 2008/2009 period. The gas price situation at that time was wholly different from the price situation today, and five years from now the price situation will be wholly different from today's, with or without PennEast.

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[21] Notably the winter of 2014/2015 was colder and had colder days than the Polar Vortex winter of 2013/2014.

[22] See Natural Gas Intelligence March 03, 2016 "Barclays Reduces 2016 NatGas Price Outlook and Sees Breakout in 2017"

[23] These projects largely involve east to west capacity additions and pipeline flow reversals to the south and west. This means that these now trapped supplies will soon have choices of markets and will flow to the most favorably priced market, whereas absent these additions, producers have few choices and compete with one another to gain access to the limited NE market, namely the subject geographic area identified by Concentric.

Are Potential Savings Impacted by Recent Electric Market Reforms?

In the past two years, both PJM and NEISO have instituted market rules which heavily incentivize generators to have fuel during peak critical periods[24]. Skipping Stone will refer to these market rule changes as "Supply Assurance Programs."

Notably also, in the short-run NEISO has instituted its Winter Reliability Program where it pays generators to have fuel oil and/or LNG in tanks ready to be used to assure such critical winter period fuel supplies are available for generation. In New England this has had the effect in both of the past two winters (2014/15 and 2015/16) of greatly dampening price spikes. In turn, price spikes in the subject geographic area have also been dampened, as the pipelines running through eastern PA and NJ also either continue north and east or supply pipelines running into New England.

Under the Supply Assurance Programs, both PJM and NEISO have auctions that create price signals and payments to generators. While significant dollars are to be paid to generators under these Supply Assurance Programs, they are amounts that are far short of amounts required to cover year-round firm transportation on interstate pipelines. As a result, anecdotally and to Skipping Stone's knowledge, gas-fired generators have either opted to install dual fuel capability, arrange for peaking LNG supplies, or make firm supply call arrangements with large wholesale players to backstop their commitments.

The likely ongoing impact of these developments is that the scrambling for supply that led to the enormous price spikes experienced during the period covered by the Concentric report are much less likely to occur in the future. Thus, it is increasingly likely that price spike avoidance, a claimed attribute of a proposed PennEast Pipeline, has in large part already, and enduringly, been addressed. To the extent, then, that the potential for future price spikes have been largely avoided by such market rule changes, the supposed benefits from such avoidance have already been realized – without the proposed presence of PennEast to do so.

[24] In PJM this market rule change is known as "Capacity Performance" and in NEISO the market rule change is referred to as "Pay for Performance".

Section V – Weak Public Benefit but Strong Financial Incentives

Given the lack of evidence from the LDC Sponsor/Shippers of their systems' load growth, as well as certain LDC Sponsor/Shippers' statements made regarding replacing some of their currently contracted interstate capacity with proposed new-build PennEast capacity, questions arise as to what could be the driver behind such a project.

Generally pipelines are proposed and built to meet known demand, such as when LDCs sign-up for expansion to serve new territories or replace over-reliance on winter-peaking resources. Pipelines can also be proposed to meet the needs of Producers who seek to move gas from capacity constrained supply areas to liquid market locations. From our review of the documents, the PennEast Pipeline is proposed to serve neither demand from LDCs nor supply from Producers.

What then is a possible motivating genesis for PennEast?

Is Return on Capital a Motivating Factor?

A potential motivator might be a rather simple one: namely, a vehicle for the LDC Sponsor/Shippers to replace dollars collected from ratepayers and sent to third-party unaffiliated interstate pipelines, with dollars collected from ratepayers and paid to themselves – or rather paid to the affiliated, non-regulated, companies owned by the same corporate shareholders as the regulated LDC signing the contracts.

Under an LLC structure such as that of PennEast, the owners (called unit-holders) are generally entitled to distributions of cash net of direct expenses and retained working capital. Direct expenses of new pipelines are both Fixed and Variable. Fixed Expenses can be simplified into the categories of a) interest payments, b) overhead, c) maintenance expenses and d) Non-income taxes (ex. property taxes and franchise taxes). Variable expenses, such as the costs of running compressors and those related to transporting gas, are collected from customers as they transport gas and do not meaningfully figure into the profits of pipeline owners. Thus, for the purposes of this analysis they will be disregarded.

In addition, Pipeline LLCs typically have a 50% Equity and 50% Debt capital structure. Below is a simplified but typical structure for the annual revenue of a pipeline and how it is generally put together.

Assuming an initial capital cost of $1.2 Billion, at the LLC level, investors would put in $600 Million and banks would finance the other $600 Million. For these purposes, Skipping Stone will assume an annual interest rate of 5%. Generally, pipelines then seek to get rates that will generate revenue based upon an annual percentage of total capital that is between 8% and 10% more than their interest rate (i.e., 13% to 15%) and apply that percentage (i.e., revenue level) to total initial capital cost (i.e., the $1.2 Billion). Assuming the lower level, 13% applied to the $1.2 Billion would mean that the pipeline would seek rates that recovered $156 MM per year. Once pipelines have determined their desired revenue level they then design their rates. In our simplified example, applying that revenue level to a pipeline with 1 Bcf per day (1,000,000 Dth/d) of capacity yields daily rates per the below.

Table 5. Simple Economic Structure of Pipeline Revenue Derivation

	Dollars ($M)	Typical Pctg.	Annual Revenue ($M)	Capacity (Dth/d)	100% LF Rate ($/Dth/d)
Assumed Interest Rate		5.0%			
Typical delta to Int Rt%		8.0%			
Upfront Costs					
Total Capital Cost	$1,200	13.0%	$156	1,000,000	$0.4274

Then, there are costs that are deducted from the pipeline's revenues which in the case of LLC structured pipelines result in distributable cash – otherwise considered return to the investors. A typical illustrative revenue, cost and distributable cash[25] structure of a new-build LLC Pipeline is set forth below.

Table 6. Typical LLC Pipeline Revenue, Cost, and Distributable Cash Structure

	Applicable Dollars for Pctg ($M)	Typical Pctg.	Annual ($M)	Capacity (Dth/d)	Cost Component in Rate
Annual Revenue			$156	1,000,000	$0.4274
Annual Costs					
Total Capital Cost Financed		50.0%			
Interest Cost	$600	5.0%	$30	1,000,000	$0.0822
Typical Annual Costs as Pctg of Total Capital Cost					
Operations & Maintenance	$1,200	1.0%	$12	1,000,000	$0.0329
Non-income taxes	$1,200	2.5%	$30	1,000,000	$0.0822
Overhead	$1,200	2.0%	$24	1,000,000	$0.0658
Total Annual Cost	$1,200	8.0%	$96	1,000,000	$0.2630
			Annual Cash ($M)		**Portion of Rate to Investor Cash**
Distributable Cash	$1,200	5.0%	$60	1,000,000	$0.1644

In addition, it is often the case that entities that form LLC Pipelines also double leverage their invested capital. This generally means that while the LLC gets 50% of its total capital cost as equity (in the case above $600 Million), the LLC Members then finance often as much as 50% of that equity contribution at their respective corporate levels. If this were to be the case with all of the LLC members of the LLC Pipeline, then their total equity cash investment would be just

[25] Note that Distributable Cash is on-going once the pipeline has established what it considers sufficient Working Capital Reserves, usually on the order of 2-4% of Total Capital Cost.

$300 Million and assuming they financed their other $300 Million at the same 5% (for an annual cost of $15 Million) then the return on equity to those partners would be $45 Million ($60 Million of cash minus $15 Million of interest) on a $300 Million cash investment. This would mean that those entities would possibly be seeing a 15% return on their cash investments.

The potential 15% return on capital is a very healthy one indeed in this overall economic environment. It is quite possible that this level of financial gain is a very strong motivator behind the proposed PennEast Pipeline.

Do Non-Arm's-Length Commitments Demonstrate Market Need?

Since the restructuring of the US Natural Gas Pipeline Industry in the mid 1990's, the Federal Energy Regulatory Commission (FERC) has had a policy of relying on contracts to pay for new pipelines and expansions of existing pipelines as evidence of market need sufficient to find such construction was in the "public convenience and necessity." A finding that a project is in the public convenience and necessity is what is required for the FERC to both grant eminent domain and to justify any construction of interstate facilities. That said, for most of the past 20 years since it established its policy of reliance on contracts as evidence of market need, those contracts were almost always between un-related parties – they were arm's-length contracts.

That previously prevailing fact is not the case with respect to 74.2% of the capacity and ownership of PennEast. In fact most of the Shippers, that is, the contracting parties on whom FERC typically relies as evidence of market need, are owners with a distinct financial interest in the existence of the pipeline and the returns it will provide. Moreover, assuming the LDC shippers are able to have their PennEast Contracts paid for by those LDCs' ratepayers, one has to question whether the FERC can continue its policy of relying on contracts as evidence of market need, the foundational aspect to a finding of public convenience and necessity.

This cannot be overstated or overemphasized.

If non-arm's-length contracts, possibly motivated by financial gain to affiliates of the shippers, are properly scrutinized then there may be *no market need* for a large proportion of the PennEast capacity upon which a finding of public convenience and necessity can rely. Instead, it may be that rather than a market need, there is purely a shareholder return "need" which should not be sufficient to grant a certificate of public convenience and necessity.

Section VI – Conclusion

As discussed in this memorandum, given all of the following:

1) The potentially evident low percentage utilization;
2) The likely existence of lower cost potentially less disruptive alternatives[26];
3) The likely negative impacts on ratepayers who presently benefit from secondary market transactions to reduce their energy costs;
4) The possible negative impact on LDC ratepayers due to turnback of capacity and/or non-renewal of capacity due to a potential glut of capacity;
5) The likely elimination of favorable pricing for gas in the supply area of the proposed line owing to other known developments;
6) The inappropriateness of relying on past events rather than modeling and forecasting future events based upon known changes as a justification for an action as large as adding a Billion cubic feet of incremental pipeline capacity to a limited geographical area;
7) Recent changes in Electric market rules which may have already eliminated the conditions that gave rise to the price spikes of the past;
8) The likely inappropriateness of reliance on non-arm's-length transactions as a foundation for finding market need; and finally,
9) The fact that most of the sponsors of the proposed line are the regulated utility-shippers' unregulated affiliates that are likely committing ratepayer dollars to provide equity returns that will be realized by the unregulated affiliates;

the Commission should institute a full evidentiary proceeding with discovery and cross-examination to determine what demand is to be met by the proposed pipeline and whether less disruptive and more cost-effective alternatives exist to meet the demand determined from such evidentiary proceeding.

[26] Especially alternatives relying on greater utilization of existing LNG facilities to meet short duration peak demands