Before the Public Utilities Commission of Nevada

Joint Application of Nevada Power Company d/b/a NV Energy, Sierra Pacific Power Company d/b/a NV Energy (referenced together as "NV Energy, Inc.") and MidAmerican Energy Holdings Company ("MidAmerican") for approval of a merger of NV Energy, Inc. with MidAmerican	))))))))))	Docket No. 13-07021

Direct Testimony of Frank Ackerman, PhD

PUBLIC VERSION

On Behalf of Sierra Club

October 24, 2013

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name, business address, and position.

A My name is Frank Ackerman. I am a Senior Economist at Synapse Energy Economics, Inc. (Synapse), which is located at 485 Massachusetts Avenue, Suite 2, in Cambridge, Massachusetts.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q Please summarize your work experience and educational background.

A I received a BA in mathematics and economics from Swarthmore College, and a PhD in economics from Harvard University. I have had more than 25 years of experience in economic analysis of energy, climate change, environmental policy, and related issues. Before joining Synapse Energy Economics, I held senior research positions at Tellus Institute in Boston; at Tufts University's Global Development and Environment Institute; and at the Stockholm Environment Institute's U.S. Center, located at Tufts University in Massachusetts. Beginning in the spring semester of 2014, I will also be a lecturer at the Massachusetts Institute of Technology.

I have filed testimony on electric utility issues in a number of states, most recently in Indiana and Kentucky. I have also testified on the economics of climate change impacts and policies before committees of the U.S. House of Representatives in Washington and the European Parliament in Brussels.

I have published more than 40 articles in professional journals, written or edited more than a dozen books, and directed numerous studies for state and federal government agencies, non-governmental organizations, and international bodies such as the United Nations. A recent research article, which I coauthored with Dr. Jeremy Fisher, analyzes long-term scenarios for the Western Electric Coordinating Council (WECC) region.[1] More detail on my experience and publications is provided in my resume, which is attached as Exhibit FA-01.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified in front of the Public Utilities Commission of Nevada?

A No, I have not.

Q What is the purpose of your testimony?

A My testimony addresses questions of market power raised by the proposed merger of the Nevada utilities (collectively "NV Energy" or NVE), and MidAmerican Energy Holdings Company ("MidAmerican" or MEHC).

Q How is your testimony organized?

I begin by addressing Ms. Solomon's testimony. The extraordinary level of confidentiality asserted for her model makes it virtually impossible for other parties to analyze its workings in any detail; we are forced to take her word for the fact that she has done the analysis correctly. Her analysis of horizontal market power presents sharply differing results from two tests for market concentration, based on Economic Capacity (EC) and Available Economic Capacity (AEC). Under the EC measure, several relevant markets are highly concentrated, and the merger would cause a significant increase in that concentration, which raises significant concerns of negative impacts on competition. With the inclusion of one essential revision to her AEC calculation, I demonstrate that the merger would have anti-competitive effects under this measure as well.

[1] Frank Ackerman and Jeremy Fisher, "Is there a water-energy nexus in electricity generation? Long-term scenarios for the western United States," *Energy Policy*, 2013.

Next, I turn to Dr. Morris' treatment of vertical market power. This merger would combine, under the same ownership, Nevada's increasingly gas-based utilities with the Kern River pipeline that is the sole source for almost all of southern Nevada's gas supplies. Thus it is difficult to accept the statement that there are no issues of vertical market power. The Morris analysis exaggerates the degree of competition available on the already heavily subscribed Kern River pipeline, and trivializes the significant costs and regulatory obstacles to the introduction of another, competing pipeline into southern Nevada.

I then address an inaccurate claim made by both Ms. Solomon and Mr. Morris. They assert that even if there were evidence of increased market power resulting from the merger, it would be immaterial because strict cost-based regulation by the Nevada PUC and FERC would be able to hold Nevada ratepayers harmless. This position would imply that regulatory review of utility mergers is necessary only in deregulated states, which is clearly at odds with FERC precedent.

The final section of my testimony offers conclusions and recommendations.

2. SOLOMON'S AEC IS NOT AN ADEQUATE MEASURE OF HORIZONTAL MARKET POWER

Q Were you able to evaluate Ms. Solomon's model?

A No. Although Solomon's workpapers showing the results of her modeling were made available, the model itself was declared to be highly confidential, protected by extraordinary levels of secrecy that definitely obstructed independent analysis. We were granted an opportunity to look at the model on a computer in a lawyer's office, under the conditions that we could not write down or quote exactly what we saw on the screen, nor take it back to our office for extended analysis.

Q Did you examine the model, despite those limitations?

A Yes – at least, I attempted to examine it. I found it to be an opaque, "black box" model, lacking in documentation that would explain its workings or calculations. When I clicked on the on-screen button that appeared to run it, an extensive series of recalculations occurred, with no explanation. My best guess is that these calculations were driven by the series of undocumented "macros" which are embedded in the model spreadsheets. Extended analysis, including permission to copy the model for examination and use in our office, would be required to understand the workings of the model.

Q What is the effect of the highly confidential status of this model?

A Solomon's model is surrounded by extraordinary claims of confidentiality, inhibiting the ability of independent analysts to examine it in any detail or estimate how much influence it has on her conclusions. In effect, the assertion of hyper-confidentiality says to others in this case, "Trust me, I'm the expert – and I can't allow you to look at the secret way in which I reached my conclusions." This is at odds with the traditional openness of all arguments to examination by all parties in public utility hearings; it threatens to introduce a new, less appealing standard of escalating secrecy, thwarting any hope of independent review of utility claims.

Q Please describe the analysis of horizontal market power offered by Ms. Solomon.

A To analyze the potential horizontal market power impacts of the proposed merger on relevant electricity markets, Ms. Solomon conducts a forward-looking, competitive analysis screen, the Delivered Price Test ("DPT").[2]

The DPT compares market concentration before and after the merger transaction, applying the Herfindahl-Hirschman Index (HHI)[3] to two measures of the market share: Economic Capacity ("EC") and Available Economic Capacity ("AEC"). EC is the amount of energy that can be delivered into a destination market at a delivered cost less than 105 percent of the destination market price; AEC is the

[2] Solomon's analysis is intended to comply with the Department of Justice and Federal Trade Commission's Horizontal Merger Guidelines: *Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, FERC Stats. & Regs ¶ 31,111 (2000), order on reh'g, Order No. 642-A, 94 FERC ¶ 61,289 (2001) ("Revised Filing Requirements" or "Order No. 642").

[3] The HHI measures market concentration by squaring the percentage market share of each firm competing in the market and summing the results; the maximum possible HHI, for a one-firm monopoly, is 10,000.

amount of EC remaining after subtracting suppliers' obligations to serve native load.

The key destination markets for the analysis are the balancing authority areas ("BAAs") of PacifiCorp-East ("PACE"), PacifiCorp-West ("PACW"), and NV Energy ("NVE"). In addition, Solomon analyzes first-tier wholesale markets (BAAs directly connected to the relevant destination markets).

Ten time periods are analyzed: off-peak, peak, and super-peak for each of the summer, winter, and shoulder seasons, as well as the peak hour of the year. In each time period, Solomon models the capacity available to serve load in each of the relevant markets by imposing simultaneous import limits (SILs) on links within the transmission network, and allocating scarce transmission capacity based on the relative amount of economic generation that each party controls at the interfaces.[4]

Q What are the results of these tests?

A FERC interprets an HHI of less than 1,000 points as evidence that a market is unconcentrated. An HHI between 1,000 and 1,800 is taken to mean that the market is moderately concentrated, while HHI above 1,800 points implies that markets are highly concentrated. In a horizontal merger, an increase of more than 50 HHI points in a highly concentrated market or an increase of 100 HHI points in a moderately concentrated market fails its screen and warrants further review.[5]

Under the EC measure, Solomon's analysis finds widespread screen failures. Combining the 10 time periods in the NVE, PACE, and PACW markets, for a total of 30 results, the post-merger HHI is above 1,800 in 24 cases, including all peak periods, and above 1,000 in 27 cases. The increase in the HHI caused by the merger is above 100 in 22 cases, and above 50 in 29 cases.[6] These results suggest

[4] Exhibit Solomon-Direct-2, pages 119-120 of 200 (Solomon FERC Affidavit Exhibit J-1, at 26-27)
[5] Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,129; see also Analysis of Horizontal Market Power under the Federal Power Act, 138 FERC ¶ 61,109 (2012).
[6] Exhibit Solomon-Direct-2, pages 177-178 of 200 (Solomon FERC Affidavit Exhibit J-9)

that under the EC screen, the proposed merger could result in significant anti-competitive impacts.

Under the AEC measure, Solomon's DPT results show virtually no screen failures. In the NVE, PACE, and PACW markets, the post-merger HHI is below 1,000 in 27 cases, and below 1,800 in all 30 cases; the increase in the HHI caused by the merger is below 50 in 25 cases, and below 100 in every case.[7]

Thus Solomon's conclusion that the merger would not create problems of horizontal market power is crucially dependent on her argument that her version of the AEC calculation is the only appropriate test to use.

Q Why does Solomon argue that the AEC measure of market power should be relied on in this case?

A On this issue, Solomon follows FERC precedent, which calls for the use of EC as a measure of market power in deregulated markets, and AEC in jurisdictions with conventional utility regulation, such as Nevada. The rationale for this distinction is that in deregulated markets, there is no obligation on any individual generator to supply any particular load, so all economic capacity, i.e. EC, could be directed to a destination market (subject to transmission constraints). In regulated markets, on the other hand, utilities have the obligation to serve native load, so only their capacity beyond the requirements of native load, i.e. AEC, is deemed available to serve a destination market.[8]

Q Do you disagree with this interpretation of the roles of EC and AEC?

A I agree with this interpretation when it is applied appropriately. There is, however, one major revision that is needed in this case. For suppliers located in the destination market itself, it makes no sense to exclude their native load from the capacity used to serve their own market's demand. In other words, EC should be

[7] Exhibit Solomon-Direct-2, pages 171-172 of 200 (Solomon FERC Affidavit Exhibit J-6)
[8] Among other FERC cases, Solomon cites *Duke Energy Corporation*, 136 FERC ¶ 61,245 at P 124 (2011) ("the AEC measure is more appropriate for markets where there is no retail competition and no indication that retail competition will be implemented in the near future").

used for suppliers located in the destination market, even when it is appropriate to use AEC for all outside suppliers.

For example, when analyzing the capacity available to serve the Nevada market, all of NV Energy's capacity (EC) is available, and is typically in use if needed, to meet in-state demand. In contrast, for an analysis of the capacity NV Energy could supply to Utah, or any other state, it would be appropriate to count only NV Energy's AEC, since the obligation to serve native load in Nevada would come first. Likewise, in an analysis of a Utah utility's available capacity, it would make sense to count its AEC for the Nevada market, but its entire EC for the Utah market.

By far the largest single difference between Solomon's EC and AEC in the Nevada market occurs for NVEnergy. Solomon excludes almost all of NVEnergy capacity from AEC. But recall that AEC for this market is defined as the capacity available to the Nevada market. In effect, Solomon has assumed that most of NVEnergy's capacity is not available to the Nevada market, because it is in use serving NVEnergy's native load. The logical inconsistency of this statement should be clear: NV Energy's native load is, by definition, part of the Nevada market.

Q How important is this point in practice?

A To test the importance of this point, I calculated a revised AEC for the Nevada market. I began by identifying the 13 suppliers, among Solomon's list of 187, that operate solely in the NVE (or NEVP plus SPPC) balancing area.[9] Four others operate both in Nevada and in other balancing areas; I treated them as if they were

[9] Based on Solomon public workpapers, spreadsheet Data Input\Generation\Wkp – Nodes Map. In addition to NV Energy, the Nevada suppliers include large generators (more than 50 MW of EC in at least one time period) Barrick Gold Corporation, LS Power Group, Morgan Stanley, Southern Nevada Water Authority, and Southwest Generation Holding Company, along with smaller generators Alterra Power, Great American, Greenline Renewables, Monument Power, Ormat Technologies, Truckee Carson Irrigation District, and US Geothermal.

entirely out-of-state suppliers, thus potentially underestimating in-state generation.[10]

I then calculated the revised AEC, defined as equal to Solomon's EC for the 13 Nevada suppliers, and equal to Solomon's AEC for all other suppliers. The revised AEC for MidAmerican after the merger is defined as PacifiCorp AEC plus NV Energy EC.

Q How large is the change in AEC due to your revisions?

A The increases in AEC for the Nevada market are shown in Table 1. The increase for NV Energy ranges from roughly 1,000 MW to more than 7,000 MW, depending on the time period. The total increase for the other 12 Nevada generators ranges from roughly 200 MW to 500 MW.

	AEC increase (MW)		
	Total	NVEnergy	Other
S_SP1	7,911	7,428	483
S_SP2	7,145	6,661	483
S_P	5,409	4,926	483
S_OP	1,987	1,737	250
W_SP	4,155	3,688	467
W_P	3,546	3,184	362
W_OP	1,865	1,636	229
SH_SP	5,652	5,231	421
SH_P	3,765	3,442	323
SH_OP	1,135	945	191

Table 1. Change in AEC due to revised treatment of NV generators

Q What does your revised AEC calculation imply about the Nevada market?

A Selected results are shown in Table 2. The Nevada market is highly concentrated (HHI above 1,800) in 7 of the 10 time periods, moderately concentrated (HHI between 1,000 and 1,800) in 2, and unconcentrated in only one.[11] The screen test

[10] The four are Caithness Energy, ENEL North America, Iberdrola, and Sempra Energy.

[11] I have counted a borderline case, S_OP, as moderately concentrated; its HHI is just short of 1,000 before the merger transaction, and well over 1,000 after it.

for mergers – an increase in HHI of at least 50 in highly concentrated markets, or at least 100 in moderately concentrated ones – fails in 6 time periods.

Q Why do some periods fail the screen test and not others?

A The screen failures are perfectly correlated with the amount of PacifiCorp AEC, which is also shown in Table 2. Screen failures occur in the six time periods when PacifiCorp has 50 MW or more of AEC for the Nevada market, but not in the four time periods when PacifiCorp AEC is lower than 50 MW. When PacifiCorp's AEC is bigger, there is a greater increase in the post-transaction HHI; when PacifiCorp's AEC is small, there is little change in the HHI. Indeed, the PacifiCorp AEC is, coincidentally, numerically quite similar to the increase in the HHI for several time periods.[12]

	HHI			Concentrated?	Fails screen?	PacifiCorp AEC
	Pre-Transaction	Post-Transaction	Increase			
S_SP1	3,036	3,038	2	High	No	2
S_SP2	3,021	3,052	30	High	No	39
S_P	2,632	2,748	116	High	**Yes**	143
S_OP	979	1,148	169	Moderate	**Yes**	276
W_SP	2,733	2,783	50	High	**Yes**	50
W_P	2,770	2,853	83	High	**Yes**	83
W_OP	1,074	1,098	24	Moderate	No	24
SH_SP	2,140	2,193	53	High	**Yes**	72
SH_P	1,818	1,944	126	High	**Yes**	174
SH_OP	748	748	0	No	No	0

Table 2. HHI and screen failures for NVE market with revised AEC

[12] This is purely a numerical coincidence, which occurs for certain combinations of market size and shares. For example, simple algebra shows that the HHI increase would be equal to the PacifiCorp AEC if the Nevada market total AEC was 10,000 MW, of which NV Energy provided 5,000 MW – which is roughly what happens in some time periods.

Q Have you done a similar analysis of the PacifiCorp (PACE and PACW) markets?

A I have not. The lack of separate data entries for PacifiCorp capacity in PACE and PACW, in Solomon's public data set, makes it impossible to directly replicate the calculations I performed for the Nevada market.

Based on a preliminary examination of the data, I anticipate that analysis of revised AEC in PACE and PACW might show screen failures in several time periods, though not as many as in the Nevada market. Revision of the AEC calculation to include EC for suppliers located in the PACE and PACW markets would be likely to increase pre-transaction HHI values, just as it did in Nevada. The change in HHI due to the merger transaction would likely depend on the amount of AEC supplied to these markets by NV Energy, mirroring the role of PacifiCorp's AEC in the Nevada market. Solomon's AEC calculations show that NV Energy has AEC of more than 100 MW in four time periods in PACE, and AEC between 40 MW and 140 MW in four time periods in PACW. In the other six time periods, NV Energy has little or no AEC. Thus I would anticipate screen failures in each PacifiCorp market could occur in some or all of the four time periods with significant AEC for NV Energy.

Q What do your revised AEC analyses imply about horizontal market power?

A My AEC calculation, using Solomon's data, revised only to correct a logical error in the treatment of home-market capacity, shows screen failures in 6 out of 10 time periods in Nevada. It could also show screen failures in up to 4 time periods in each of the PacifiCorp market areas, although I have not been able to carry out that calculation. I believe that this is sufficient to trigger concern about the impact of the proposed merger on competition in Nevada (and perhaps in other markets), requiring mitigation measures to ensure competitive access to Nevada markets.

Q [redacted]

Q [redacted]

3. KERN RIVER CREATES SIGNIFICANT VERTICAL MARKET POWER CONCERNS

Q Please summarize the arguments on vertical market power made by Dr. Morris.

A Morris examines potential market power in fossil fuel markets related to PacifiCorp's ownership of coal mines, and MEHC's ownership of the Kern River natural gas pipeline and the BNSF railroad. For the purposes of his analysis, he defines the relevant upstream product market as consisting primarily of natural gas and coal, and groups the two together, citing their substitutability.

In defining the geographic market for delivered energy, Morris notes that "holders of capacity rights to downstream delivery zones on interstate natural gas pipelines may use their capacity rights to deliver gas within a broad upstream zone," and thus "holders of capacity rights can shift deliveries to locations that place the highest value on that gas."[13] Moreover, Morris asserts that "even if a fuel supplier could set different prices within a small area, it would typically face competition 'over the wires' to supply generation."[14]

Morris defines suppliers of natural gas to include firm shippers on interstate pipelines with long-term contracts, noting that such shippers could compete with

[13] Application Exhibit 1, page 288 of 355 (Morris FERC Affidavit at 18)
[14] Application Exhibit 1, page 289 of 355 (Morris FERC Affidavit at 19)

the pipeline in offering new capacity to prospective new shippers in the short-run.[15]

To assess market concentration, Morris employs the HHI measure to assess short-run market conditions. He finds that the NVE area is only moderately concentrated, with an HHI of 1,038. He finds almost all other regional markets to be either competitive or moderately concentrated.

In the long run, Morris asserts that the Applicants face significant competitive pressure to expand pipeline capacity and rail service, implying that they will not withhold capacity expansions or foreclose capacity expansion to electric power generators.[16] Moreover, he notes that capacity right holders benefit more than pipeline companies from shortages, because pipelines are subject to cost-of-service rate regulation and are not allowed to bundle gas sales.[17] Finally, he claims that "entry is easy for long-run competition," and that even the threat of entry is sufficient to negate any harm from market concentration.[18]

Q Please explain your concerns about the impact of this merger on vertical market power.

A The proposed merger would combine, under the same corporate owner, Nevada's increasingly gas-based electric utilities and the pipeline that supplies almost all of southern Nevada's natural gas. In such a transaction, the concern about vertical market power should be obvious; it is more difficult to explain the calculations that supposedly demonstrate the absence of vertical market power.

Q Please describe the role of the Kern River pipeline in the regional economy.

A Kern River is an interstate natural gas pipeline with a capacity of approximately 2.167 Bcf/d of capacity that runs from Wyoming to California. MEHC advertises to investors that Kern River supplies 32 percent of California's demand for

[15] Application Exhibit 1, page 293 of 355 (Morris FERC Affidavit at 21)
[16] Application Exhibit 1, page 296 of 355 (Morris FERC Affidavit at 26)
[17] Application Exhibit 1, page 297-298 of 355 (Morris FERC Affidavit at 27-28)
[18] Application Exhibit 1, page 299 of 355 (Morris FERC Affidavit at 29)

natural gas (other sources suggest somewhat less), and more than 80 percent of southern Nevada's natural gas.[19] Payments to Kern River are roughly 3 percent of NV Energy's total operating costs.[20]

Q How do you evaluate Morris' arguments that there is potential competition among companies with contracts to deliver gas via Kern River, and with others that might choose to supply gas via Kern River in the future?

Kern River's capacity is heavily subscribed. Long-term contracts, with an average duration of seven years, account for 92 percent of its capacity.[21] The pipeline is, in general, already fully used, with scheduled daily capacity routinely averaging more than design capacity; in 2012, daily capacity was 117 percent of design capacity.[22]

The scarcity of pipeline capacity is likely to become an even greater issue in Nevada, as generation from natural gas continues to increases. According the Energy Information Administration, electricity generation from natural gas in Nevada nearly tripled between 2001 and 2012, from 6,743 GWh to 18,798 GWh. Without substantial expansion, supply is unlikely to keep pace with demand in the near future, resulting in scarce pipeline capacity that could be manipulated to artificially raise rates.

Q [redacted]

A [redacted]

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[19] MidAmerican Energy Holdings Company, *MidAmerican Energy Holdings Company 2013 Fixed Income Investor Conference*, presentation ("MEHC Investors presentation"), available at http://www.midamerican.com/include/pdf/2013_investor_conference.pdf

[20] Payments from NV Energy to Kern River for 2014 are forecast to be $66.6 million (Application Exhibit 21, p.3), while NV Energy's total operating costs were $2.2 billion in 2012 (NV Energy, "Annual Income Statement," http://www.nvenergy.com/company/investors/fundamentals/income.cfm).

[21] *MEHC Investors presentation*, slide 83.

[22] *MEHC Investors presentation*, slide 86.

Q Do issues of market power arise in other Kern River markets?

A Yes. Most of the capacity of the Kern River pipeline is used to deliver gas to California. That state's massive gas market is dependent on a small number of pipelines, with a high HHI index, as shown in Table 3.[23]

	Northern CA	Southern CA	Nonutility	Total
CA Prodn	30	68	1,073	148
GTN	3,053	32	-	507
El Paso	466	1,996	0	748
Transwestern	127	356	-	152
Mojave	-	1	4	1
So Trails	2	3	-	2
Kern River	24	388	4,249	550
Total	3,703	2,844	5,325	**2,108**

Table 3. Market power in the California gas market: HHI by pipeline

Q Has FERC addressed market power questions that arise in mergers between utilities and pipelines?

A Yes. "Convergence mergers" between electric utilities and natural gas pipelines raise significant vertical competition concerns, which FERC has noted in both its Order No. 642 and previous cases. The merger of MidAmerican with NV Energy raises issues similar to those considered by FERC in *San Diego Gas & Electric Co. and Enova Energy, Inc.*, 79 FERC ¶ 61,372 (1997), 83 FERC ¶ 61,199 (1998). In that proposed transaction, SoCalGas (Southern California Gas Company), a subsidiary of Enova (now known as Sempra), delivered natural gas to the majority of gas-fired generators in Southern California, giving SoCalGas access to sensitive market information regarding these generators' cost and fuel use. FERC found that the merged company could then restrict competing generators' access to delivered gas services, thus raising these generators' input costs and reducing their ability to compete.[24]

[23] Calculated from the California Gas Report, available at http://energyalmanac.ca.gov/naturalgas/natural_gas_receipts.html.

[24] *See San Diego Gas & Electric Co. and Enova Energy, Inc.*, 83 FERC ¶ 61,199, P2 (1998) ("Enova").

FERC identified seven ways that the merger could impair competition, stating that SoCalGas could:

> (1) use competitive market information (such as gas usage, service requirements of competing generators, advance knowledge of competitors' projected fuel consumption, patterns, and costs) to manipulate costs and service to SDG&E's advantage;
>
> (2) offer transportation discounts to SDG&E that are not offered or made available to competing generators;
>
> (3) withhold or deny access to pipeline capacity to competing generators;
>
> (4) offer service contracts providing SoCalGas with unilateral and arbitrary control over pipeline access, delivery points, etc.;
>
> (5) manipulate storage injection schedules to effectively withhold pipeline capacity from competing generators at strategic times and thereby drive up wholesale electricity prices;
>
> (6) force competing generators to renominate volumes to other delivery points or purchase additional firm pipeline capacity by citing the existence of difficult-to-verify operational constraints on SoCalGas' system; and
>
> (7) manipulate the terms and conditions of intrastate gas tariffs to SDG&E's advantage by, for example, enforcing the letter of SoCalGas' tariff when dealing with competing generators while enforcing the terms of the tariff less rigorously when dealing with SDG&E.[25]

FERC noted the existence of the above threats to competition, despite the existence of FERC Order 636 (which went into effect prior to the Enova case), which required unbundling and open access equally available to other market players. Because of the possibility of anticompetitive behavior, FERC declared that mitigation measures would be required to prevent SoCalGas from discriminating against non-affiliates:

[25] *See* Enova pp. 2-3.

> The mitigation measures needed involve codes of conduct (to regulate the sharing of market information); application of the requirements of our Order No. 497 (which is designed to prevent abuses of the affiliated relationship between jurisdictional pipelines and marketers) to SoCalGas; and a requirement that SoCalGas operate its electronic bulletin board (EBB), GasSelect, as an interactive same-time reservation and information system. … We also noted that another way to eliminate the vertical market power problems would be for SDG&E to divest its gas-fired plants.

Q Are these concerns relevant to a merger involving Kern River and NV Energy?

A Yes. In the instant case, many similar threats exist. All of the natural gas used by NV Energy in southern Nevada is supplied by Kern River, either directly by Kern River or indirectly from Kern River through Southwest Gas.[26] Should rival generators seek to construct new natural gas generation in southern Nevada, the merged parties may act in anti-competitive ways (such as those outlined by FERC above) to prevent the rival companies from gaining a foothold.

The threat of anticompetitive behavior is even more of a concern as natural gas usage in Nevada increases. As mentioned above, data from the Energy Information Administration show that electricity generation from natural gas in Nevada rose nearly three-fold between 2001 and 2012, significantly increasing Nevada's dependence on natural gas and the pipelines that deliver it. The current oversubscription of Kern River implies that pipeline capacity is scarce, leaving buyers vulnerable to price manipulation.

Q What actions do the Companies propose to take to prevent anticompetitive behavior between Kern River and the Nevada Utilities?

A Mr. Fehrman states that he expects the effect of the transaction on the relationship between Nevada Power and Kern River will be "minimal and in compliance with

[26] Application Exhibit 1, page 280 of 355 (Morris FERC Affidavit at 10)

applicable federal and state requirements."[27] Mr. Fehrman further suggests that the same procedures as observed between MidAmerican's electric utility (MEC) and gas pipeline (Northern Natural Gas) in the Midwest will apply to the relationship between the Nevada Utilities and Kern River. He states:

> The contracts between MEC and Northern Natural Gas are negotiated on an arms' length basis. Consistent with arm's length treatment of procurement of regulated services from an affiliate, nonpublic information regarding Northern Natural Gas rate cases and similar filings and rate case strategies are not discussed between Northern Natural Gas and MEC personnel or discussed on joint calls where such personnel are participating, including legal, regulatory and executive personnel of each organization.[28]

Fehrman also claims that in the case of MEC and Northern Natural Gas, all applicable contracts are filed with the Iowa Utilities Board and subject to regulatory scrutiny. In addition, MEC may intervene before the FERC regarding changes in costs or terms of service.[29]

Q Do such actions reduce the risk that the transaction will result in anti-competitive behavior?

A No. The incentive for Nevada Energy to intervene before FERC and protest rate cases, tariff changes, or modification of service rules to protect the interests of Nevada customers may be significantly dampened by the transaction. After a merger, to address situations where the interests of Kern River and Nevada Energy appear to be in opposition, one branch of MidAmerican would have to take action against another. This is a greater hurdle than taking similar action against an unaffiliated company.

[27] Fehrman Direct Testimony, page 28
[28] Fehrman Direct Testimony, page 28
[29] Fehrman Direct Testimony, page 29

Q Will the entry of competitors alleviate concerns about market power related to Kern River in the long-run?

No. Morris makes this claim, but fails to provide persuasive support for it. His characterization that “entry is easy” dramatically understates the barriers to entry that exist for natural gas pipelines. As noted in Morris’s affidavit, in order to alleviate market power, new entrants must be able to achieve “a significant impact on price” in the relevant market within two years from initial planning to significant market impact.[30]

Under the heading, “Entry is Easy for Long-Run Competition,” Morris asserts that “In the natural gas industry, entry (or the threat of entry) routinely has significant market impact within two years.”[31] Morris then goes on to argue that a pipeline need not even be constructed, as the mere threat of entry is a sufficient antidote to anti-competitive behavior in the natural gas industry.

Q Is there theoretical backing for Morris’ claims that threats of entry can deter anti-competitive behavior?

A There is, but it is not applicable in this case. Morris’s assertion relies on the theory of contestable markets, which contends that “In a perfectly contestable natural monopoly market, actual entry is redundant. The mere threat of entry will discipline the market even if it is a natural monopoly.”[32] For this theory to hold the market must be “perfectly contestable,” i.e., there must be no barriers to entry. This necessary condition is utterly lacking in the case of natural gas pipelines, which are characterized by significant sunk costs and lengthy construction periods, preventing new entrants from quickly and easily offering competitive products.

Not only does a natural gas pipeline represent a large sunk cost, but the time required to obtain permits and construct a new pipeline is substantial, on the order

[30] Department of Justice and Federal Trade Commission’s *Horizontal Merger Guidelines* (2010)
[31] Application Exhibit 1, page 300 of 355 (Morris FERC Affidavit at 30)
[32] E. Bailey and J. Panzar “The contestability of airline markets during the transition to deregulation,” *Law and Contemporary Problems,* 44 Winter 1981, page 145

of four years – much more than the two years required by regulators for "timely entry."

Q What do gas industry experts say about the time required to construct a new pipeline?

A Donald Santa, President and CEO of the Interstate Natural Gas Association of America, recently testified on this topic before the U.S. House of Representatives' Committee on Energy and Commerce:

> The GAO looked at recent "major" projects… and determined that the average length of time to process an application was 558 days, with times ranging from 370 to 886 days, or in other words, from one year to almost 2.5 years. This did not include the time needed for obtaining permits after a FERC certificate is granted, nor did it include the time to develop a project before beginning the pre-filing process or the time to construct the project once all authorizations had been received. **Recent industry experience suggests that it typically takes about four years for an interstate natural gas pipeline to go from concept to operation**.[33]

Q Does actual or threatened entry of new pipelines hold down the rates of return earned by pipelines in practice?

A No. In a 2011 analysis, which I have included as Exhibit FA-02, the Natural Gas Supply Association (NGSA) calculated the rate of return earned by 32 interstate gas pipelines from 2005 to 2009. Kern River had a 5-year average rate of return of 21 percent; MidAmerican's other pipeline subsidiary, Northern Natural Gas, had an average of 19 percent. The average for all 32 pipelines was above 14 percent.[34] These rates are well above the levels typically allowed under FERC regulations –

[33] Testimony of Donald F. Santa before the Subcommittee on Energy and Power, Committee on Energy and Commerce, U.S. House of Representatives, regarding the "Natural Gas Pipeline Permitting Reform Act," July 9, 2012 (emphasis added). Available at http://docs.house.gov/meetings/IF/IF03/20130709/101102/HHRG-113-IF03-Wstate-SantaD-20130709.pdf. *See also* U.S. Government Accountability Office, *Pipeline Permitting: Interstate and Intrastate Natural Gas Permitting Processes Include Multiple Steps, and Time Frames Vary,* Report to Congressional Committees, February 2013. Available at http://www.gao.gov/products/GAO-13-221.

[34] *NGSA Pipeline Cost Recovery Analysis*, provided as an attachment to a letter to U.S. Senator Lisa Murkowski, http://www.apga.org/files/public/correspondence/let_Murkowski_022411.pdf .

and they are certainly high enough rates of return to attract additional competitors, if the pipeline market were as contestable as Morris has claimed.

4. COST-BASED REGULATION DOES NOT ELIMINATE PROBLEMS OF MARKET POWER

Q Please explain the argument about regulation as an antidote to market power, made by Ms. Solomon and Dr. Morris, which you are challenging.

Both witnesses Solomon and Morris assert that Nevada and FERC regulations would protect consumers from any exercise of undue market power, if such market power existed.

For example, Solomon states that "all wholesale and retail sales by Applicants in the NVE BAA must be made at cost-based rates regulated by the Commission and/or the PUCN…."[35] Similarly, Morris says that "Nevada state law provides that net benefits from off-system sales accrue to the NV Energy Utilities' retail and wholesale cost-based customers, and not to NVE shareholders. Therefore, if the combined entity attempted to exercise vertical market power, there would be no additional gains to the combined firm."[36] Morris also contends that pipelines "cannot directly benefit from not expanding capacity efficiently because they are subject to cost-of-service rate regulation and are not allowed to bundle gas sales."[37]

This argument, if accepted, would mean that any merger and any degree of horizontal or vertical market power would be acceptable in a regulated jurisdiction – contrary to both economic theory and established precedent.

Q Why is this argument contrary to economic theory?

A Without adequate competition to discipline the market, the burden of protecting consumers falls entirely to regulators. The ability of regulators to protect consumers, however, is hampered by asymmetric information and inadequate

[35] Solomon FERC Affidavit Exhibit J-1, page 8
[36] Application Exhibit 1, page 43 of 355 (Application page 41)
[37] Application Exhibit 1, page 298 of 355 (Morris FERC Affidavit page 28)

resources. ("Asymmetric information" refers to the fact that the regulated company knows much more than the regulators about its business operations and choices.) MIT economist Paul Joskow highlights the limitations of cost-of-service regulation, writing:

> The "traditional" cost of service regulation model… reflects efforts to respond to imperfect and asymmetric information that all regulatory processes must confront…. Regulators in the U.S. and other countries have long known, however, that **better data and analysis cannot fully resolve the asymmetric information problem**.[38]

Further, Joskow notes that the problem of asymmetric information can arise in many areas:

> Managers have discretion to make choices not only about input proportions… but on how hard they will work to minimize the firm's costs….Accordingly, **the regulated firm may use its information advantage (asymmetric information) strategically to exploit the regulatory process** to increase its profits or pursue other managerial goals, to the disadvantage of consumers.[39]

When the market is excessively concentrated, competitors are unable to enter the market to discipline the behavior of the participants holding market power. In such cases, regulators may lack the information and resources to ensure that all decisions made are optimal for consumers.

This threat is increased significantly where a merger combines a regulated utility with unregulated affiliates. The Public Utilities Commission of Nevada (PUCN) considered this issue in a 1998 decision on affiliate transaction rules. The Federal Trade Commission ("FTC") submitted comments during that proceeding that identified the inherent risks in allowing affiliate transactions:

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[38] P. Joskow, *"Regulation of Natural Monopoly"* in *Handbook of Law and Economics, Vol.2,* Polinsky and Shavell, eds., pages 1286-1287 (emphasis added).

[39] P. Joskow, *Incentive Regulation and Its Application to Electricity Networks*, Review of Network Economics, Vol. 7, Issue 4, Dec. 2008, pages 550-551(emphasis added).

> [T]here is a strong likelihood that a utility will favor its affiliates where these affiliates are providing services in competition with other, non-affiliated entities. . . . [In addition,] there is a strong incentive for regulated utilities or their holding companies to subsidize their competitive activity with revenues or intangible benefits derived from their regulated monopoly businesses. ... **current regulations ... are not adequate to prevent or discourage** [this] anticompetitive behavior. ... [40]

Q Does regulatory precedent demonstrate concerns about market power, even in the case of mergers of traditionally regulated utilities?

A Yes. Because of the threats posed by market power, FERC has repeatedly expressed concern with increases in market concentration in traditionally regulated jurisdictions, as well as in deregulated areas. For example, in the recent FERC decision regarding the acquisition by Duke Energy of Progress Energy, FERC determined that market power mitigation would be required due to unacceptable levels of concentration in North and South Carolina.[41] These are states with conventional cost-of-service regulation.

In the case of PacifiCorp's 2008 merger with Chehalis Power, a Washington state generation facility, FERC reviewed market power arguments in detail, before approving the transaction. FERC approval was clearly conditional upon finding that there were no relevant increases in market power, despite the traditionally regulated electricity markets in Washington and in almost all of PacifiCorp's service territory.[42]

Q. How does this concern regarding market power affect Nevada?

A. Operating in a regulated market does not eliminate the risks of manipulation through market power; it merely subjects the participants to oversight. The efficacy of that oversight to eliminate the risks of market manipulation requires

[40] *Comment of the Staff of the Bureau of Economics of the Federal Trade Commission*, Before the Public Utilities Commission of Nevada, Dkt. No. 97-5034 (Sept. 22, 1998) (quoting Public Utility Commission of Texas, 23 Tex. Reg. 5294 (May 22, 1998) (emphasis added).
[41] *Duke Energy Corp*., 136 FERC ¶ 61,245 (2011) (Merger Order)
[42] *PacifiCorp*, 124 FERC ¶ 61,046 (2008) (Merger Order)

substantial resources on the part of the oversight agency. Oversight of a much larger, multi-state (indeed, multinational), multi-industry enterprise requires greater resources than oversight of an independent, single-state utility such as Nevada Energy. If regulators had unlimited resources to address the problem, this would be less of a concern; but in the real world of limited resources, the concern is inescapable. The Commission should very carefully consider whether it is willing and able to accept the substantially increased burden of policing a post-merger utility that will have significant incentives and multiple opportunities for anti-competitive behavior.

5. <u>CONCLUSIONS AND RECOMMENDATIONS</u>

Q Please summarize your conclusions.

A In reviewing Ms. Solomon's analysis of horizontal market power, I first noted that the excessive level of confidentiality surrounding her model essentially prevents independent review of that model in any detail.

Taking her publicly available inputs and outputs as a starting point, I then corrected one logical error in the definition of Available Economic Capacity (AEC), the basis for the standard screen tests for horizontal market power in a conventionally regulated market such as Nevada. With that correction, the Nevada market has screen failures, indicating that the merger would cause a significant increase in market power, in 6 of the 10 modeled periods of the year. Although it was not possible to replicate that analysis for the PacifiCorp market areas, it appears possible that they would also have screen failures in several periods.

In reviewing Dr. Morris' analysis of vertical market power, I argued that increases in market power should be expected in a merger combining Nevada's increasingly gas-based utilities with the principal gas pipeline that supplies them. The Kern River pipeline supplies most of southern Nevada's gas, including most or all of the gas used for electricity generation in the region. The pipeline is already operating above design capacity, and does not appear to have the ability to support the continuing expansion of natural gas use in Nevada. Scarcity and rising costs are a likely result. The claim that the pipeline market is contestable by actual or potential new entrants is inconsistent with the long lead times required to construct new pipelines, and by the above-average rate of return earned by Kern River and other pipelines.

I then addressed the claim made by both Solomon and Morris that cost-based regulation, by FERC and by the Nevada Commission, ensure that any exercise of market power could not lead to unjustified rate increases. Both economic theory and ample regulatory precedent argue against this view. Increases in the market power and size of regulated entities imposes additional burdens on regulators, who have only limited resources for oversight.

Q What are your recommendations to the Commission?

A Procedurally, I recommend that the Commission should allow little if any of the hyper-confidentiality that encumbered this proceeding and effectively prevented review of issues such as the actual operation of the Solomon model. Open exchange among parties to a regulatory hearing, with proprietary information protected by ordinary levels of confidentiality when appropriate, is essential for review of proposals such as the merger addressed in this case.

Substantively, I conclude that there are serious grounds for concern about increases in both horizontal and vertical market power. If the merger is allowed to proceed, it must be accompanied by significant mitigation measures.

Mitigation of horizontal market power often includes expansion of transmission links, to allow additional competition from other balancing areas (other states, in this case). [redacted]

Mitigation of vertical market power, in this instance, should include support for additional gas pipelines that could bring substantial new capacity into southern Nevada. Regulatory obstacles to such pipelines should be reviewed and reduced wherever possible; the parties to the merger might be required to allow, or refrain from interfering with, new pipelines into the region. Kern River could be asked to demonstrate that it is setting rates consistent with FERC regulations, and comparable to the rates earned in truly (as opposed to theoretically) contestable markets.

Q **Does this complete your testimony?**

A Yes, it does.

Exhibits to Direct Testimony of Frank Ackerman

Exhibit FA-01: Frank Ackerman’s CV.

Exhibit FA-02: Natural Gas Supply Association Pipeline Cost Recovery Analysis.

Exhibit FA-01

Frank Ackerman’s CV.

Frank Ackerman

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. Senior Economist, 2012 – present.
Consult on issues of energy economics, environmental impacts, climate change policy, and environmental externalities valuation.

Stockholm Environment Institute - U.S. Center, Somerville, MA. Senior Economist and Director of Climate Economics Group, 2007 – 2012.
Wrote extensively for academic, policy, and general audiences, and directed studies for a wide range of government agencies, international organizations, and nonprofit groups.

Tufts University, Global Development and Environment Institute, Medford, MA. Senior Researcher, 1995 – 2007.
Editor of GDAE's *Frontier Issues in Economic Thought* book series, a coauthor of GDAE's macroeconomics textbook, and director of the institute's Research and Policy program. Taught courses in the Tufts Department of Urban and Environmental Policy and Planning.

Tellus Institute, Boston, MA. Senior Economist, 1985 – 1995.
Responsible for research and consulting on aspects of economics of energy systems and of solid waste and recycling.

University of Massachusetts, Boston, MA. Visiting Assistant Professor of Economics, 1982 – 1984.

Dollars and Sense, Somerville, MA. Editor and Business Manager, 1974 – 1982.

EDUCATION

Harvard University, PhD, Economics, 1975
Swarthmore College, BA, Mathematics and Economics, 1967

AFFILIATIONS

Economics for Equity and the Environment (E3 Network), Portland, OR
Co-founder and steering committee member, 2007 – present

Center for Progressive Reform, Washington, DC
Member scholar, 2002 – present

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Ackerman F., *Stern Advice for Copenhagen: Review of Blueprint for a Safer Planet, by Nicholas Stern.* Nature Reports: Climate Change, April 2009.

Ackerman F., *The Outer Bounds of the Possible: Economic Theory, Precaution, and Dioxin*. The Dioxin 2003 conference, Boston, August 2003, Published in *Organohalogen Compounds* 65, pp. 378-81.

Exhibit FA-02

Natural Gas Supply Association Pipeline Cost Recovery Analysis.

AMERICAN PUBLIC GAS ASSOCIATION

February 24, 2011

The Honorable Lisa Murkowski
Ranking Member
Committee on Energy and Natural Resources
Washington, DC 20510

Dear Ranking Member Murkowski,

On behalf of the American Public Gas Association (APGA), I want to draw your attention to the Natural Gas Supply Association's (NGSA) recently released study, "Pipeline Cost Recovery Analysis," (see attached NGSA executive summary).

The NGSA study is released on an annual basis and analyzes the return on equity for 32 major interstate natural gas pipelines over a five-year period (2005-2009). The study concludes that, for the 2005-2009 period, "using 12% as a nominal target allowed return, these 32 pipelines over-recovered their costs by approximately $4.1 billion…even taking into account those pipelines that under-recovered." This conclusion simply reaffirms the conclusions of previous NGSA studies: Congress must finally fix Natural Gas Act (NGA) Section 5.

Just as Congress fixed Federal Power Act (FPA) Section 206 in 1988 to provide the Federal Energy Regulatory Commission (FERC) with the authority to provide refunds for over-recovering, Congress should now provide FERC with that same authority under NGA Section 5. The FERC's ability to exercise it authority under FPA Section 206 is <u>not</u> retroactive ratemaking. Therefore, to harmonize FERC's NGA Section 5 authority to FPA Section 206 would <u>not</u> provide the FERC with retroactive ratemaking authority. Any refund of monies, charged and collected by a pipeline in excess of its rate of return, would only include those sums collected <u>from and after the date a NGA Section 5 complaint is initiated</u> against the offending pipeline.

APGA is the national trade association representing over 700 municipally and publicly-owned local natural gas distribution systems that work to meet the daily energy needs of over 5 million customers in 36 states. Publicly-owned gas systems are not-for-profit retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities, almost all of which rely on a single pipeline provider to transport their gas supplies from the wellhead to the city gate. The Natural Gas Act is their only protection against paying excessive rates.

In this study, it is notable that seven of the 32 pipelines exceeded 18% return on equity. These are dollars that could have gone into local businesses, paying food bills, mortgages, or into a child's education. Instead, these local dollars continue to flow upstream into the pipelines' coffers. These are also dollars that can affect job creation since many industrial concerns, such as chemical and fertilizer manufacturers, are heavily dependent upon natural gas and they pay the same excessive rates as everyday citizens.

The reason for this situation is very straight-forward— the FERC is currently unable under NGA Section 5 to effectively restrain pipeline over-recovery because of the absence of refund authority under NGA Section 5. This was also the situation under the complaint section of the Federal Power Act (Section 206) until 1988, when Congress took stock of the situation and amended FPA Section 206 to give FERC the authority to order refunds from and after the date a complaint was filed. Thus, under FPA Section 206 if a utility is found to have overcharged customers, that utility must refund the overcharges to its customers, whereas by contrast FERC does not have the same authority under the NGA to provide for reimbursement to overcharged gas transportation customers.

Since under NGA Section 5 the FERC may only rule that a rate reduction take effect prospectively *after* FERC's order is issued, the pipelines have an obvious and strong incentive to delay the proceeding interminably (since no refunds can be ordered under NGA Section 5 during the interim even if the pipelines are determined to have overcharged their customers). All FERC commissioners, without regard to party affiliation, have decried this absence of refund authority under NGA Section 5.

One of the arguments raised in the past by the pipeline lobby against providing FERC with this consumer protection tool is that it would have a negative impact upon a pipeline's ability to attract new capital, and this in turn would have an adverse impact on infrastructure investment. This argument is a red-herring with no basis in fact. The FERC, in establishing just and reasonable rates, provides for the recovery of all costs, including debt costs and a fair return on equity. And a fair return on equity must, as the Supreme Court long ago mandated, permit the regulated utility to go to the marketplace to raise capital at reasonable rates. In addition, most new infrastructure projects are undertaken by pipelines pursuant to negotiated rates that would not be impacted by amending NGA Section 5 to provide relief for recourse rate customers such as the members of APGA.

APGA strongly supports the growth and expansion of investor-owned interstate natural gas pipelines. However, it is absolutely critical that the healthy growth of these pipelines be achieved within the confines of the Natural Gas Act's mandate that the customers of these pipelines pay "just and reasonable" rates for transportation of natural gas supplies, which are critical to America's economic prosperity and security. This is especially so for shippers such as the vast majority of the members of APGA that purchase natural gas transportation from a single pipeline and hence cannot avoid paying excessive rates by shopping for (and negotiating with) another service provider.

Ironically, the pipelines never argue that they are not over-recovering their costs - only that if caught they should not have to refund the overcharges. The FERC Commissioners, all of whom support infrastructure improvement **and** the amendment of NGA Section 5 to provide for the establishment of a refund-effective date, understand that this is not an "either-or" proposition. The Congress should not allow itself to be fooled by arguments that are paper-mache thin and that are recognized by the regulators themselves to have no merit.

As the Committee considers developing an energy package, I urge you to include Section 5 reform legislation which provides natural gas consumers with the same level of protection from overcharges that currently exists for electric consumers.

Sincerely,

Bert Kalisch
President & CEO

NGSA Pipeline Cost Recovery Analysis

The Natural Gas Supply Association (NGSA) analyzed pipeline cost recovery to assess the actual return on equity earnings of thirty-two major interstate natural gas pipelines over a five-year period. The thirty-two pipeline companies evaluated represent approximately 80 percent of the capacity in the interstate market. This study examined relevant interstate pipeline costs and revenues using a cost-of-service model based on *FERC Form No. 2* (Form 2) reports. This analysis is NGSA's eleventh annual evaluation of major interstate pipeline return on equity earnings.

As the study highlights, there are a number of instances in which pipeline revenues exceed those necessary to recover costs and collect a fair return on investment. In fact, our analysis of thirty-two pipeline companies shows that over a five-year period pipelines earned roughly $4.1 billion more than they would have collected with an average of 12 percent allowed return on equity. While many pipelines have clearly performed effectively for shareholders, there is a point at which rate of return levels require close FERC oversight. Below is a brief explanation of the methodology used to calculate the returns.

Scope
NGSA's cost recovery analysis of thirty-two pipelines combines three elements to determine pipelines' return on equity: (1) rate base, (2) net revenues, and (3) total cost of service. For purposes of this study, NGSA selected 32 major interstate pipelines. NGSA reviewed the total population of major interstate pipelines and selected those pipelines that were large in terms of both revenue and physical assets as well as the amount of time lapsed since their rates were reviewed. For each pipeline examined, the analysis reviewed the most recent five years of financial data (2005 - 2009) available at the time the study was conducted.

Methodology
NGSA developed its cost recovery analyses using annual financial data as provided in Form 2 for a five-year period (2005 - 2009). Using annual balance sheets as well as revenue and expense data from Form 2, NGSA built a cost-of-service model for each pipeline company. Using this information, we calculated each pipeline's annual actual return on equity. Consistent with FERC policy, these calculations used only the jurisdictional portion of the costs reflected in Form 2. For example, NGSA utilized methodologies consistent with those that would be used by FERC in a traditional rate case proceeding, such as those applied to the debt/equity ratio as well as in the determination of total rate base

and revenues. In those instances where interpretation of Form 2 accounts was required, NGSA used the more conservative options.

Three Elements

We used the following data analyses and processing steps to develop the three elements needed to determine the return on equity of each pipeline.

1. *Rate Base.* Rate base includes gas plant in service, accumulated depreciation, gas stored-noncurrent, accumulated deferred income taxes (ADIT), working capital (including materials and supplies) and regulatory assets and liabilities.
2. *Revenues.* We calculated net revenues from total operating revenues by excluding revenues for transition costs and take-or-pay as well as sales revenues (Accounts 480-484).
3. *Cost-of-Service.* NGSA developed the pipeline's total cost-of-service, including an annual allowed return on rate base, federal and state income taxes, other taxes, depreciation, and operation and maintenance (O&M) costs. Multiplying the total rate base by the weighted allowed rate of return on rate base yielded the pipeline's allowed return on rate base. To determine the weighted allowed rate of return on rate base, the debt and common equity costs of capital were multiplied by their respective capitalization ratios and added together. The capitalization ratios and current debt and equity cost of capital were obtained from Form 2 if the values were within a range FERC has historically approved. Otherwise, these data were obtained from the pipeline's most recent filed and/or approved section 4 rate case information.

   To calculate the federal income taxes, the total allowed return on rate base was multiplied by the ratio of the weighted return on equity to the total return on rate base and then multiplied by the federal tax factor pursuant to FERC regulations. Federal income taxes were then included as a component of the cost-of-service. We used the actual state income tax rates where readily available. For others, the state income tax rates were estimated individually for the pipeline using the federal taxable net income and state taxes charged during the year as provided in Form 2. The individual state taxes were added together and then calculated as a percentage of federal income taxes. State tax percentages were confirmed by examining several of the test years, and state income taxes were then added to the total cost-of-service.

   Several cost components for O&M expenses listed in Form 2 also needed to be removed such as sales and compressor fuel expenses to appropriately determine a pipeline's non-gas cost of service in order to properly align costs with reported revenues. Depreciation expenses and other taxes from Form 2 were added to determine the total cost of service.

Calculation of Return on Equity

Finally, we calculated the pipeline's over- or under-recovery of costs by subtracting the total cost of service from net revenues. Because the study's total cost of service calculation already includes the pipeline's allowed return, the difference between the cost-of-service and net revenues reflects the pipeline's actual over or under recovery of costs. The formula to calculate actual earned rate of return on equity is as follows:

$$ROE = \frac{\left[\left(CR - \left(CR * \left(\frac{FGIT}{(1+FGIT)}\right)\right) - (CR * (SIT * FGIT))\right) + \left(AR * \left(\frac{ER}{TR}\right)\right)\right]}{RB * EC}$$

Where:

ROE	=	Actual Earned Rate on Equity
CR	=	Cost Over- or Under- Recovery
$FGIT$	=	Federal Grossed-Up Income Tax Rate
SIT	=	State Income Tax Rate as a Percentage of FIT
AR	=	Allowed Return on Rate Base
ER	=	Allowed Equity Return on Rate Base rate
TR	=	Allowed Total Return on Rate Base rate
RB	=	Total Rate Base
EC	=	Equity Capitalization Ratio

The annual rates of return on equity for each of the thirty-two pipelines were weighted across the five-year period based on the equity portion of rate base to calculate a weighted average rate of return on equity for each pipeline.

In addition, NGSA conducted a separate analysis to determine the pipelines in the cost recovery analysis that do not appear to employ a fuel tracking mechanism to true-up their fuel costs during the analysis period based on a review of their tariffs. NGSA's analysis determined that 9 of the 32 pipelines analyzed do not appear to employ a true-up mechanism during the analysis period. NGSA developed a valuation over five years (2005 - 2009) of excess retained fuel for these pipelines. The results of the fuel recovery analysis are included in the calculations of pipeline returns summarized in this report.

Study Results

Using the methodology described above, NGSA's analysis shows that over a five-year period (2005 – 2009) the average after-tax returns on equity (ROE) for eighteen pipelines were at or exceeded an average allowed return of 12 percent, while fourteen of the thirty-two pipelines fell short of 12 percent. Seven pipelines experienced average ROEs over the five-year-period of 18 percent or higher. Using 12 percent as a nominal target allowed return, these 32 pipelines over-recovered their costs by approximately $4.1 billion before taxes over the five-year period, even taking into account the pipelines that under-recovered. Just looking at the eighteen pipelines that over-recovered, the cost over-recovery for the five-year period is nearly $5.5 billion.

NGSA, like every segment of the natural gas industry, strongly supports healthy returns for interstate pipelines so they will have the incentive to build infrastructure to bring gas to market. When pipeline returns continually exceed the average allowed rate of return on equity, FERC must call into question whether pipelines are adequately being held accountable for their earnings. At the very least, this sustained period of over-recovery, reflected herein, suggests that there may be additional efficiencies to be shared with the marketplace. How those efficiencies may be shared, without impinging on the pipelines' need to be compensated for their market risks, is a fruitful area for the industry as a whole to continue to explore.

Natural Gas Supply Association
Actual Pipeline Rate of Return on Equity

NGSA Analysis - 32 Pipelines

	Pipeline Name	Year Ended 2005	Year Ended 2006	Year Ended 2007	Year Ended 2008	Year Ended 2009	5-year Average Weighted by Equity Ratebase
●	1 Natural Gas Pipeline Company of America LLC 1/	34.0%	39.7%	38.3%	42.2%	37.2%	38.4%
●	2 Kinder Morgan Interstate Gas Trans. LLC	24.6%	38.2%	24.9%	27.7%	25.7%	28.1%
●	3 Dominion Transmission, Inc. (formerly CNG Trans.)	24.0%	19.4%	24.4%	25.5%	26.0%	23.5%
	4 Great Lakes Gas Transmission Ltd. Partnership	19.8%	21.5%	20.3%	20.9%	23.7%	21.2%
	5 Kern River Gas Transmission Co.	9.7%	15.9%	26.5%	35.3%	23.7%	21.0%
	6 Panhandle Eastern Pipe Line Company, LP	33.2%	33.8%	22.1%	16.2%	15.0%	20.9%
	7 Northern Natural Gas Company	13.2%	18.1%	18.8%	24.6%	19.4%	18.9%
	8 Northern Border Pipeline Company	17.4%	17.2%	18.4%	20.0%	14.6%	17.5%
	9 Mojave Pipeline Company 2/	21.1%	27.5%	15.4%	9.6%	12.3%	17.3%
●	10 National Fuel Gas Supply Corporation	19.3%	17.6%	15.8%	17.4%	15.3%	17.0%
	11 CenterPoint Energy Gas Trans. (formerly Reliant)	21.8%	15.4%	11.9%	16.9%	14.3%	15.3%
	12 Colorado Interstate Gas Company	12.4%	20.1%	19.4%	13.2%	13.2%	15.1%
	13 Florida Gas Transmission Company, LLC	13.9%	17.2%	17.1%	14.9%	13.2%	15.1%
●	14 Transwestern Pipeline Company, LLC	19.7%	17.2%	15.4%	16.6%	9.7%	14.7%
	15 Columbia Gas Transmission, LLC	11.5%	14.3%	14.1%	12.8%	17.2%	13.8%
	16 Texas Eastern Transmission, LP	13.5%	12.2%	15.6%	9.9%	14.6%	13.2%
	17 Transcontinental Gas Pipe Line Company, LLC	13.1%	9.4%	12.2%	14.8%	13.6%	12.6%
	18 ANR Pipeline Company	17.0%	13.1%	12.4%	10.7%	10.6%	12.5%
	19 Questar Pipeline Company	11.1%	15.0%	11.0%	13.0%	10.2%	11.9%
	20 Southern Star Central Gas Pipeline, Inc. (formerly Williams)	10.7%	12.5%	10.6%	9.5%	12.3%	11.1%
●	21 Tennessee Gas Pipeline Company	13.2%	12.1%	11.4%	11.2%	8.0%	10.9%
	22 Gas Transmission Northwest Corp. (formerly PG&E)	10.2%	8.5%	10.9%	11.4%	12.5%	10.6%
	23 Southern Natural Gas Company	10.9%	10.9%	10.6%	11.0%	9.8%	10.6%
	24 El Paso Natural Gas Company	7.9%	12.2%	10.6%	10.3%	11.5%	10.5%
	25 Columbia Gulf Transmission Company	9.5%	7.1%	10.4%	15.6%	8.7%	10.4%
	26 Trunkline Gas Company, LLC	8.5%	9.6%	9.0%	9.0%	11.9%	9.7%
	27 Northwest Pipeline GP	9.8%	5.0%	10.5%	10.7%	10.3%	9.2%
●	28 Gulf South Pipeline Co., LP (formerly Koch Gateway)	16.4%	23.0%	8.2%	5.6%	6.6%	8.7%
●	29 East Tennessee Natural Gas, LLC	7.2%	7.8%	9.1%	8.4%	10.0%	8.6%
	30 CenterPoint Energy Mississippi River Transmission	5.8%	4.4%	4.9%	9.0%	10.6%	7.2%
	31 Equitrans, LP	7.2%	11.6%	6.1%	3.8%	5.9%	6.0%
●	32 Sea Robin Pipeline Company, LLC 3/	-18.8%	-2.7%	-6.0%	-1.3%	-7.4%	-6.2%
	Simple Average	14.0%	15.8%	14.4%	14.9%	13.8%	
	Weighted Average by Equity Ratebase	14.4%	14.6%	14.7%	14.7%	13.9%	14.4%

● Pipelines NGSA's analysis determined do not have a fuel tracking mechanism to true-up their fuel costs at the end of the five-year analysis period.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties of record in this proceeding by electronic service.

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Dated at San Francisco, CA, this 24th of October of 2013.

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