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AUG 13 2013

PUBLIC SERVICE
COMMISSION

Via Overnight Mail

April 22, 2013

Mr. Jeff Derouen, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: ***Case No. 2012-00578***

Dear Mr. Derouen:

Please find enclosed the original and ten (10) copies of the PUBLIC VERSION of the KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. POST HEARING BRIEF for filing in the above-referenced docket. I also enclose the CONFIDENTIAL PAGES to be filed under seal.

The information filed under seal is information that Kentucky Power sought confidential treatment through various Petitions for Confidential Treatment which have been approved by the Commission. KIUC redacted this information in order to protect Kentucky Power's interests in keeping this information confidential

By copy of this letter, all parties listed on the Certificate of Service have been served. Please place this document of file.

Very Truly Yours,

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.
Jody Kyler Cohn, Esq.
BOEHM, KURTZ & LOWRY

MLKkew
Attachment
cc: Certificate of Service
Quang Nyugen, Esq.
Jeff Cline (cover letter only)

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by mailing a true and correct copy via electronic mail (when available) and regular U.S. Mail to all parties on this 12th day of August, 2013.

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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF: THE APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE TRANSFER TO THE COMPANY OF AN UNDIVIDED FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION AND ASSOCIATED ASSETS; (2) APPROVAL OF THE ASSUMPTION BY KENTUCKY POWER COMPANY OF CERTAIN LIABILITIES IN CONNECTION WITH THE TRANSFER OF THE MITCHELL GENERATING STATION; (3) DECLARATORY RULINGS; (4) DEFERRAL OF COSTS INCURRED IN CONNECTION WITH THE COMPANY'S EFFORTS TO MEET FEDERAL CLEAN AIR ACT AND RELATED REQUIREMENTS; AND (5) FOR ALL OTHER REQUIRED APPROVALS AND RELIEF	:	**Case No. 2012-00578**

RECEIVED

AUG 13 2013

PUBLIC SERVICE COMMISSION

PUBLIC VERSION

POST HEARING BRIEF OF KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

1. **KIUC Supports The Stipulation**

Throughout the 1980's, 1990's and 2000's, Kentucky Power Company ("Kentucky Power") routinely has had among the lowest electric rates in the United States. That is a fairly notable accomplishment for a small utility serving a poor rural customer base located in a mountainous service territory. Kentucky Power's low electric rates served to attract and retain large energy intensive industrial customers, including the members of Kentucky Industrial Utility Customers, Inc. ("KIUC"): Marathon Petroleum, AK Steel, Air Liquide, EQT Gas and Air Products and Chemicals. These KIUC companies purchase approximately 20% of the energy sold by Kentucky Power at retail and provide high wage, high benefit family supportive jobs. Each of these companies was directly involved in the negotiation of the July 2, 2013 Stipulation and Settlement Agreement and fully supports it. All Stipulations involve compromise. There are aspects of the Agreement that we do not think are perfect, but on balance the Stipulation provides a reasonable solution to a host of complicated problems. Approval of the Stipulation is the safest, most prudent and very likely the least cost course of action.

2. Kentucky Power's Low Cost History, The Challenges It Now Faces And The Trust It Has Earned.

Kentucky Power has been able to provide low cost electric service for decades primarily due to its affiliation and joint operating agreements with the other AEP East utilities. Since 1951, Kentucky Power, Ohio Power, Indiana & Michigan, and Appalachian Power have jointly operated their systems under the AEP Interconnection Agreement (AEP Power Pool). Under the Interconnection Agreement, Deficit Pool members (such as Kentucky Power) could rely on the capacity of the Surplus Pool members (such as Ohio Power) through Capacity Equalization Payments. All Pool members could buy surplus energy from their sister companies at cost, not market. Further, all profits from off-system sales were shared ratably according to each Company's Member Load Ratio regardless of which power plant actually made the sale. Joint economic dispatch, coordinated outage maintenance and shared engineering services also contributed to Kentucky Power's low rates. Finally, by being a member of the AEP Pool, Kentucky Power was able to benefit from the economies of scale of joint ownership (or lease) of large highly efficient generating units which would otherwise far exceed the needs of a small utility. The AEP Pool Agreement worked well for all of its Members, but Kentucky Power was particularly benefited.

Kentucky Power is now at a major crossroad. The Interconnection Agreement will expire at the end of 2013. This means that Kentucky Power will no longer be able to rely on the surplus capacity and energy of its sister companies. The 800 mw Big Sandy 2 will be forced to retire in mid-2015 due to the Mercury and Air Toxic Standards ("MATS") environmental rules.

In less than two years, as basically a stand-alone utility, Kentucky Power will be required to reliably meet the needs of its customers with a new generation resource portfolio. After careful consideration, the members of KIUC believe that the generation resource portfolio presented in the Stipulation provides the least cost and most stable option. That generation resource portfolio includes: 780 mw of the highly efficient, fully environmentally compliant capacity from the super critical Mitchell Units 1 and 2, natural gas conversion of the 268 MW Big Sandy 1 Unit, 390 mw of capacity pursuant to the existing lease agreements for 15% of Rockport Units 1 and 2 (these leases expire in the 2021/2022 time frame), 75 mw of low cost interruptible capacity that qualifies toward meeting Kentucky Power's PJM FRR obligations and a doubling of DSM resources within three years. This generation portfolio is not without risk. But there would be risk no matter what portfolio is chosen.

One less obvious benefit of acquiring 50% of Mitchell is that it effectively extends Kentucky Power's successful historic business model of achieving economies of scale through partnership with its affiliated companies even after the expiration of the Interconnection Agreement. Mitchell is a large highly efficient station that Kentucky Power could not build or operate on its own. Owning half of Mitchell will allow the ratepayers of Kentucky Power to continue to benefit from AEP's world class engineering practices and efficient operations.

The Mitchell units are well-maintained supercritical units,[1] that have been updated and improved throughout their operating lives,[2] and that have one of the lowest heat rates in the country.[3] The Mitchell units are environmentally controlled with both SCR and FGD units,[4] and are expected to meet the 2015 MATS standards.[5] The Mitchell station is like a quality old house that has been completely renovated. While the structure is original, the major operating components are new.

> "*The age of the unit – I think that one thing that maybe is not completely understood is a power plant is a system of parts. For instance, in 2007 we put about a billion dollars of equipment in there. That – that equipment, those fans, those scrubbers, they're six years old. They're not forty years old. They're six years old.*"[6]

The Mitchell Units were appropriately described as "*two of the jewels of AEP.*"[7]

There may have been some initial suspicion that Ohio Power was somehow unloading uneconomic generation assets on Kentucky Power. We don't view it that way. We view this transaction as an opportunity to benefit from Ohio's decision to deregulate and require all of the utilities in that jurisdiction to be wires-only companies with no generation ownership. Nationwide, utilities have announced that they plan to retire 57,178 MW of small, inefficient and environmentally uncontrolled coal units (see attached). These retirements alone will take this Country a long way toward reducing CO_2 emissions. The remaining large, efficient and clean coal units

[1] LaFleur Hearing Testimony at 559.
[2] *Id.* at 558-559
[3] *Id.* at 560.
[4] McManus Direct Testimony at 4-5; LaFleur Hearing Testimony at 571.
[5] McManus Direct Testimony at 5.
[6] *Id.* at 558-559
[7] LaFleur Hearing Testimony at 560.

– like LG&E's Trimble County Units 1 and 2, KU's Ghent Units 1-4 and Kentucky Power's Mitchell Units 1 and 2 – could very well end up being valuable strategic assets that will be in a strong position going forward. This Country's power grid infrastructure must have base load generation and natural gas combined cycle generation cannot be the exclusive answer.

Twenty years ago when the first President Bush signed into law the acid rain provisions of the Clean Air Act there was lots of speculation that SO_2 emission allowance costs and scrubber costs would dramatically increase electricity prices. That did not happen. CO_2 and GHG restrictions are coming. President Obama made that clear. But the President also made clear that the strategy would be flexible and take into account the adverse effects that higher power costs would have on the economy and jobs. This means that efficient coal plants have a role in America's energy future.

This Commission has wisely and steadily regulated the utilities under its jurisdiction at least for decades. But regulation is not management. That is the utility's job. And utilities that have a proven track record of good management should get the benefit of the doubt. AEP/Kentucky Power certainly fits into that category.

Kentucky Power has demonstrated on paper that acquiring 50% of Mitchell Units 1 and 2 combined with the conversion of Big Sandy Unit 1 to natural gas is by far the least-cost option. And that demonstration was made before considering all of the concessions and benefits in the Stipulation. But paper is paper. Changing one assumption in a long-term economic study can significantly change the results Ultimately it comes down to whether the management of AEP/Kentucky Power has earned the trust of this Commission.

The Stipulation provides for a seamless transition from the old world of the Interconnection Agreement and Big Sandy Unit 2, to the new world of a more diverse generation supply portfolio for a stand-alone Kentucky Power, which nevertheless retains a high degree of coordination among the AEP affiliates. The Commission can be confident that the Stipulation will work and will produce reasonable rates for consumers.

3. **<u>The Rates Increases Under The Stipulation Are Reasonable</u>**

As shown on the Company's response to Staff Data Request 5-10 if the Stipulation is approved the expected rate increases would be 5.33% on January 1, 2014 and 8.21% on June 1, 2015.[8] This is certainly more attractive than the proposed 23.9% rate increase that is currently pending and which will be withdrawn if the Stipulation is approved. It is also more attractive than the 25.59% rate increase which would have occurred if the scrubber retrofit on Big Sandy 2 would have been pursued.[9] It is really quite amazing that for very modest rate increases all of the following can occur: the Interconnection Agreement is terminated, Big Sandy 2 is retired, the 268 MW Big Sandy 1 is converted to natural gas and 780 mw of Mitchell is acquired.

The 5.33% rate increase on January 1, 2014 is comprised of the $44 million Asset Transfer Rider less the $16.75 expected fuel savings from Mitchell. Paying only $44 million annually to own Mitchell for the 17 month period January 2014 to June 2015 is very economic since the actual fixed costs to own the facility are $137.8 million annually as shown on the Company's response to AG 2-12.[10] As discussed at the hearing, owning Mitchell for 17 months for $44 million while the true annual cost is $137.8 million is the approximate $100 million "haircut" (actually $93.8 million annually) which Kentucky Power agreed to in the Stipulation. Over the 17 month period, the "haircut" to Kentucky Power is $132.9 million.[11] This concession recognizes that Kentucky Power would be acquiring Mitchell before Big Sandy 2 is retired and therefore slightly before new capacity is needed. During this 17 month period Kentucky Power's return on equity is expected to be less than 6%.[12]

After the 5.33% rate increase on January 1, 2013 comes a second modest increase of 8.21% seventeen months later on July 1, 2015. The July 1, 2015 8.21% rate increase is the net result of many moving parts: adding the full revenue requirement of Mitchell to base rates and the environmental surcharge, pulling all Big Sandy 2 and all coal related Big Sandy 1 costs out of base rates, reflecting the termination of the AEP Interconnection Agreement in base rates (elimination of capacity equalization payments) and the environmental surcharge

[8] AG Hearing Exhibit 8.
[9] *Id.*
[10] AG Hearing Exhibit 5; Kentucky Power Post-Hearing Data Response to KIUC Item 1.
[11] $93.8 million ÷ 12 x 17.
[12] Kentucky Power Response to Staff 5-1.

(elimination of surplus companies' environmental costs), recovering Big Sandy 2 retirement and decommissioning costs on a levelized basis over 25 years through the Asset Transfer Rider 2 and recovering the Big Sandy FDG study costs. But for the Stipulation, all of these matters would have to be separately litigated.

Under the Stipulation, between January 2014 and July 2015 rates would increase by only 13.98%.[13] No party dislikes rate increases more than KIUC and its Members. But those Members also recognize that the retirement and replacement of Kentucky Power's major generating resource will raise rates to some degree. The rate increases under the Stipulation are reasonable and manageable.

4. **<u>50% Of Mitchell Combined With The Big Sandy 1 Gas Conversion Is The Least Cost Option</u>**

As part of its Strategist modeling analysis, Kentucky Power evaluated eleven unique resource variations to address the unit disposition decisions for Big Sandy Units 1 and 2.[14] These alternatives are summarized below:

Option	Big Sandy Unit 2 Replacement	Big Sandy Unit 1 Replacement
1A	Retrofit with DFGD	20% Mitchell
1B	Retrofit with DFGD	PJM Market (10 yrs)[15]
2A	Replace with NGCC	20% Mitchell
2B	Replace with NGCC	PJM Market (10 yrs)
3A	BS1 Repower	20% Mitchell
3B	BS1 Repower	PJM Market (10 yrs)
4A	PJM Market (5 yrs)	PJM Market (5 yrs)
4B	PJM Market (10 yrs)	PJM Market (10 yrs)
5A	50% Mitchell	Nat. Gas Conversion
5B	PJM Market (5 yrs)	Nat. Gas Conversion
6	50% Mitchell	PJM Market (10 yrs)

The costs to Kentucky Power as a stand-alone utility were then modeled using an expected or base commodity price forecast for coal, natural gas, market prices for on and off peak energy, market capacity and CO_2. In addition to the "base" commodity price forecast, the Company also used four additional pricing scenarios

[13] AG Hearing Exhibit 8.
[14] Weaver Direct Testimony at 5.
[15] For alternatives with market purchases for periods less than the full study period the Strategist® model selected either a new-build combined cycle or simple-cycle combustion turbine to provide capacity and energy for the remainder of the period.

to represent the effects of higher fuel costs, lower fuel costs, an earlier CO_2 pricing date, and no CO_2 pricing.[16] These additional commodity pricing scenarios allowed the Company to evaluate each option over a range of plausible pricing scenarios.[17] The Strategist modeling demonstrates that the transfer of a 50% undivided interest in the Mitchell Generating Station, combined with the conversion of Big Sandy Unit 1 to a natural gas fired steam boiler (Option 5A), is the least cost option for Kentucky Power. The relative Cumulative Present Worth (CPW) of all other options compared to Option 5A is summarized below:[18]

Option	Big Sandy Unit 2 Replacement	Big Sandy Unit 1 Replacement	CPW v. Option 5A (In Millions Of Dollars)
1A	Retrofit with DFGD	20% Mitchell	625
1B	Retrofit with DFGD	PJM Market (10 yrs)	819
2A	Replace with NGCC	20% Mitchell	483
2B	Replace with NGCC	PJM Market (10 yrs)	682
3A	BS1 Repower	20% Mitchell	558
3B	BS1 Repower	PJM Market (10 yrs)	754
4A	PJM Market (5 yrs)	PJM Market (5 yrs)	532
4B	PJM Market (10 yrs)	PJM Market (10 yrs)	557
5A	50% Mitchell	Nat. Gas Conversion	-
5B	PJM Market (5 yrs)	Nat. Gas Conversion	379
6	50% Mitchell	PJM Market (10 yrs)	156

50% of Mitchell combined with the conversion of Big Sandy 1 to natural gas is by far the lowest-cost alternative over the study period, and that is true over all five commodity pricing scenarios utilized by the Company in its modeling.[19]

Kentucky Power also ran a series of sensitivity analyses to confirm that Option 5A (Mitchell Transfer and Big Sandy Unit 1 gas conversion) was the least cost alternative. First, in response to a data request from Commission Staff, Kentucky Power evaluated a case where a baghouse would have to be constructed at the Mitchell Plant, even though there is no reason to believe that one will be required.[20] Even with the additional cost

[16] Weaver Direct Testimony at 17-18; Bletzacker Direct Testimony at 12-13.
[17] Bletzacker Direct Testimony at 13.
[18] *See* Exhibit SCW-1R.
[19] *See* Exhibit SCW-1R.
[20] Weaver Hearing Testimony at 701; McManus Hearing Testimony at 476.

associated with installing a baghouse, Option 5A remains the least cost alternative with a CPW $274 million less than the next closest, non-Mitchell, option.[21]

In response to a request from Vice Chairman Gardner, Kentucky Power also evaluated the relative economics of a new "Option 2C" (natural gas combined cycle plant constructed in 2017 plus the Big Sandy Unit 1 natural gas conversion) and found it to be $560 million more costly, on a CPW basis, than Option 5A.[22]

Finally, Kentucky Power evaluated Option 5A under a scenario where the Mitchell Units were retired five years early in 2035. There is no reason to believe that the Mitchell Units will be retired early.[23] However, the sensitivity analysis shows that, even if the Mitchell Units were to retire early, Option 5A remains the lowest cost alternative for the long-term needs of Kentucky Power's customers.[24] This analysis should at least partially address some of Chairman Armstrong's concerns about the age of the Mitchell Units.

As part of his evaluation, Mr. Weaver calculated a "break-even" point where the long-term CPW of a combined cycle plant would equal the CPW of the Mitchell Transfer Option.[25] For a new-build combined cycle plant, the cost would have to be reduced from over $1,000/kW to $448/kW, to reach a point of economic indifference with Option 5A.[26] Because it would likely have poorer thermal efficiency and cost more to operate, the cost of an existing combined cycle plant would have to be reduced even further, to as low as $310/kW, to reach the same point of economic indifference.[27] However, there is no evidence in the record to suggest that such highly discounted combined cycle capacity is available for purchase.

Importantly, all of the net present value model runs prepared by AEP witness Mr. Weaver assumed full Mitchell cost recovery beginning January 1, 2014. Mr. Weaver's model runs did not assume a $132.9 million under recovery pursuant to the Stipulation over the first 17 months of his studies. Full Mitchell cost recovery with

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[21] Weaver Hearing Testimony at 700-702; Kentucky Power's Response to Commission Staff Data Request 2-17.
[22] Kentucky Power's Response to Commission Staff Post-Hearing Data Request, PHDR-14.
[23] LaFleur Hearing Testimony at 564-65.
[24] Kentucky Power's Response to Commission Staff Post-Hearing Data Request, PHDR-14.
[25] Weaver Rebuttal Testimony at 20.
[26] Weaver Rebuttal Testimony at 21.
[27] Weaver Rebuttal Testimony at 21.

no "haircut" was assumed in Mr. Weaver's Strategist runs shown in Kentucky Power Hearing Exhibit 1, as well as his "stacking" analysis of the conforming RFP bids shown on Exhibit SCW-2S.

"[redacted]"[28]

If those model runs had reflected the "haircut" in the Stipulation, then Option 5A (50% of Mitchell 1/1/2014 and Big Sandy 1 gas conversion 7/1/2015) would have been the least cost plan by an additional $132.9 million (discounted by 17 months).

For future decision making the Commission should continue to evaluate the status of the Rockport Units. All of the model runs conducted by AEP assumed that the Rockport lease agreements would be extended. Kentucky Power currently has unit power agreements entitling it to 15% of Rockport Units 1 and 2, or 390 MW. Rockport Units 1 and 2 are thirty year old supercritical coal facilities located in Indiana. The Rockport leases expire in the 2021/2022 time frame. If the Rockport lease agreements are allowed to expire, then Kentucky Power will have the ability to diversify its generation resource portfolio even more, and such diversification could occur just as many predict the new CO_2/GHG rules would be effective. The economics of extending the Rockport unit power agreements or allowing them to expire should be continually studied through the ongoing IRP process.

[28] Weaver Hearing Testimony Confidential at 104-105.

5. Mitchell Pricing Under The Stipulation Is At Or Below Fair Market Value

Part of the hearing was devoted to the question of whether the record contains sufficient evidence to support a conclusion that the net book cost of Mitchell is at or below its fair market value, considering that no RFP specifically for Mitchell was done. In fact, KIUC witness Kollen raised doubts about this issue in his pre-filed direct testimony. But as the record currently stands there is more than sufficient evidence to make such a finding, especially in light of the fact that for the first 17 months of the transaction consumers will be paying $132.9 million below the net book cost of the plant.

At the outset it is necessary to note that the Mitchell transaction is unique. Buying half of a two unit 1,600 mw power plant is not an everyday occurrence. As Dr. Weaver testified, it is more like buying the Empire State Building than like buying a house.[29] Unlike stocks or bonds, there is no readily available published index to verify pricing. A more customized and judgmental process is necessary. If the Commission were to require 100% mathematical precision, then a transaction like this could never be approved and a valuable opportunity for consumers could be missed.

Because of the amount of generation to be acquired (up to 1,100 MW),[30] and the need for base load energy,[31] as well as the absence of recent comparable coal plant transactions,[32] Kentucky Power elected to use the Strategist modeling tool to determine whether the fair market value of the Mitchell generating station exceeded its net book value transfer price.[33]

Strategist is a widely-used and sophisticated modeling tool relied upon by utilities and regulatory bodies in connection with resource planning and unit disposition analyses, and provides a transparent means of establishing the market value of assets such as the Mitchell generating station.[34] In addition to its use in this case, as well as the earlier Scrubber case,[35] Kentucky Power relies upon Strategist as part of its Integrated Resource

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[29] McDermott Hearing Testimony at 637.
[30] Weaver Direct Testimony at 37.
[31] *Id.*
[32] Fransen Rebuttal Testimony at 12; Fransen Hearing Testimony at 514-515.
[33] Weaver Direct Testimony at 37.
[34] *Id.* at 5.
[35] *Id.* at 2.

Plans submitted to this Commission.[36] According to Mr. Fransen, the type of analysis performed by Mr. Weaver provides both the best[37] and only appropriate[38] basis for determining the fair market value of a base load plant such as the Mitchell generating station.

Kentucky Power established that the fair market value of the Mitchell Transfer Interest exceeded its net book value through its modeling of Option 2 of Mr. Weaver's analysis. Option 2 modeled the cost on a cumulative present worth basis over the thirty year study period of a new-build combined cycle unit.[39] As explained by Mr. Weaver, this option provided a reasonable means of determining the relationship between the net book value of the Mitchell Transfer Interest and its fair market value.[40]

In his Supplemental Testimony, AEP witness Mr. Weaver determined that 50% of Mitchell was less expensive than the "stacked" alternative of the conforming bids received in the 250 MW RFP. The RFP bids can fairly be characterized as a fair market value alternative. As shown on SCW-2S, 50% of Mitchell is at least [redacted] million less expensive than the "stacked" conforming bids from the 250 MW RFP. But Mitchell is more than [redacted] million less expensive than the fair market value alternative for three reasons. First, the market alternative contains "*tens, or even hundreds of millions of dollars of cost risk exposure (RRaR)*" from market based energy sources that was not factored in.[41] Second, Exhibit SCW-2S does not include the fact that the rating agencies consider purchase power agreement as debt, thus requiring additional equity. This increases purchase power costs.[42] Finally, Exhibit SCW-2S assumes full Mitchell cost recovery beginning January 1, 2014. The approximate $132.9 million "haircut" in the Stipulation makes the least cost option even less costly.[43]

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[36] *Id.* at 2, 6.
[37] Fransen Hearing Testimony at 512.
[38] *Id.* at 513.
[39] Weaver Testimony at 6.
[40] *Id.* at 37; Weaver Rebuttal Testimony at 16.
[41] Weaver Supp. Testimony at 13; Weaver Hearing Testimony Confidential at 106.
[42] Weaver Hearing Testimony Confidential at 125-126.
[43] *Id.* at 104-105.

Additional evidence that the fair market value of 50% of Mitchell (780 mw) exceeds its $537.8 million net book cost is provided by the non-conforming responses to the 250 MW RFP. In the RFP two non-conforming bids were received for base load coal generation located in MISO. The first bid from [redacted] offered to sell the [redacted]. Therefore, this [redacted] bid was for about half the mw for about the same price.[44] Plus, [redacted] has a scrubber that would require [redacted] million to comply with CSAPR.[45] Right now Mitchell is fully compliant with all environmental regulations, including the vacated CSAPR. The second bid from [redacted] was for the [redacted] station. While capacity from [redacted] has a lower capital cost than Mitchell, it is a far less efficient plant with much higher operating costs.[46] In any event, there is not available transmission to move either [redacted] out of MISO into PJM.[47]

Under SEC rules AEP was required to do an impairment analysis of the Mitchell Units. If AEP's independent auditors found that the net book cost of Mitchell was below its fair market value, then an asset write down would be required. There was no such asset write down for Mitchell. According to the impairment analysis, the book cost of Mitchell is less than its fair market value. The purpose of the impairment analysis is to determine whether [redacted][48] In performing the impairment analysis Kentucky Power was required to choose assumptions that were reviewed by its outside auditors as to their reasonableness[49] concerning [redacted][50] As described by Mr. Kollen these assumptions [redacted][51]

[44] Hayet Hearing Testimony Confidential at 16-17.
[45] *Id.* at 17.
[46] Pauley Hearing Testimony Confidential at 7.
[47] *Id.*
[48] Kollen Hearing Testimony Confidential at 20.
[49] *Id.* at 21.
[50] *Id.* at 19.
[51] *Id.* at 20.

Notwithstanding the impairment analysis' use of more pessimistic assumptions than those employed in the Company's Strategist modeling, Mr. Kollen independently concluded the impairment analysis demonstrated that the fair market value of the Mitchell units exceeds their net book value:

[redacted][52]

6. **<u>In Addition To Low Rates The Stipulation Provides Many Additional Benefits</u>**

The Stipulation also provides the public with many benefits which could not be achieved in litigation. These include increased shareholder funding for the Home Energy Assistance Program, $500,000 of shareholder funding for economic development for Lawrence County and counties contiguous to it, and doubling DSM funding over three years.

Paragraph 21 of the Stipulation deserves special note. It gives the Commission a safety valve in the event that this Commission determines that Mitchell is no longer the least cost resource due to federal, state or local environmental requirements relating to greenhouse gas emissions. In such event, Mitchell can be retired for Kentucky ratemaking purposes and the Company will recover its remaining investment in the plant over a period determined by the Commission at a debt only return. A debt only return is far less than the Company's overall cost of capital, which would provide savings to consumers. The Commission's authority to declare Mitchell retired for Kentucky ratemaking purposes is independent of how the plant is treated by PJM or FERC.

This ability to "retire" the Mitchell units for ratemaking purposes was recognized by Mr. Kollen as "*extremely valuable to customers*."

> "*Q. – just assume that the co – this commission determined that – that Mitchell should be retired for rate-making purposes even though West Virginia wants to keep it going*
>
> *A. Sure.*

[52] Kollen Confidential Hearing Testimony at 24.

Q. The – the – the benefit of having a debt-only return, over a period of time that the Commission determines is reasonable, is significant very significant versus the overall costs of capital?

A. It is very significant. Let's say, for example, that there is $200 million worth of costs here, and let's say that the grossed-up rate of return is 12 percent. That would be $24 million, 12 percent times $200 million, and a debt-only cost, let's say at four percent, would be $8 million. There's a $16 million savings just by virtue of using a debt-only rate of return on the same investment.

Q. So having this safety valve in paragraph 21 is valuable, and having it at a debt-return is very valuable?

A. It is extremely valuable to customers."[53]

7. **<u>The Virginia Commission's Decision To Deny The Mitchell Transfer To Appalachian Power Should Have No Bearing Here.</u>**

On July 31, 2013 the Virginia Corporation Commission entered its Order in Case No. PUE-2012-00141 denying the transfer of a fifty percent undivided interest in the Mitchell generation station to Appalachian Power Company.[54] Kentucky Power's application to this Commission seeking authorization for the transfer of the remaining fifty percent interest in Mitchell is independent of any action by either the Virginia or West Virginia commissions. Kentucky Power continues to require both the capacity and energy available to it through the Mitchell transfer and the transfer, particularly under the terms of the Stipulation and Settlement Agreement, continues to represent the least cost alternative to address the Company's needs. If the other fifty percent undivided interest in the Mitchell generating station is not transferred to Appalachian Power Company, Kentucky Power anticipates that interest will remain with AEP Generation Resources Inc.[55] Under those circumstances, a revised Mitchell Operating Agreement will be filed with the Federal Energy Regulatory Commission providing that the Kentucky Power Company will operate the Mitchell generating station on behalf of itself and AEP Generation Resources Inc.[56] The fact that Kentucky Power employees will operate the plant is probably on balance a positive development.

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[53] Kollen Hearing Testimony at 245.
[54] Kentucky Power August 5, 2013 Supplemental Response to Staff.
[55] *Id.*
[56] *Id.*

Appalachian Power and Kentucky Power are different utilities, with different reserve margins, with different customer bases and with different generation resource needs. The fact that the Virginia Commission reached a different conclusion than that proposed under the Stipulation should carry no weight. The same would be true if Virginia had approved the Mitchell transfer.

CONCLUSION

The Stipulation is reasonable and it should be approved. The Stipulation results in only modest rate increases over the next two years. It also reasonably resolves a host of related issues that would otherwise have to be litigated separately. There is substantial evidence in this record to conclude that 50% of Mitchell combined with the Big Sandy 1 gas conversion is the least-cost plan, and that conclusion is enhanced by the benefits and concessions in the Stipulation.

Respectfully submitted,

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ATTACHMENT

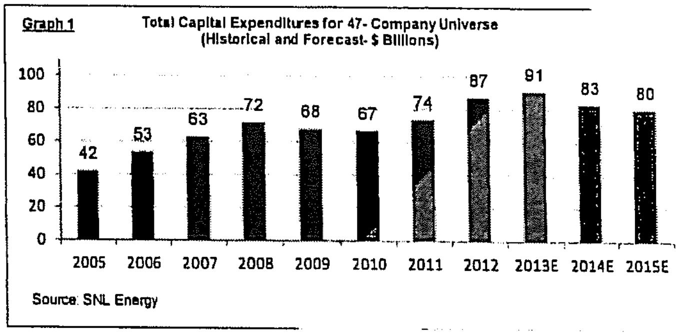
SNL Energy
FINANCIAL FOCUS

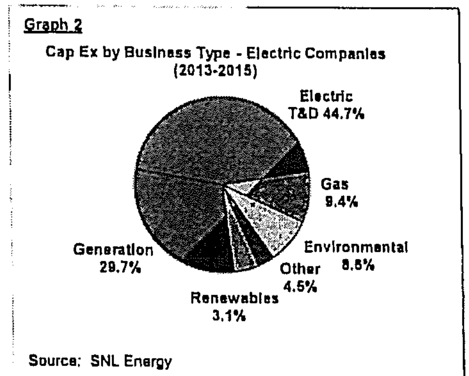
FINANCIAL FOCUS SPECIAL REPORT May 31, 2013

CAPITAL EXPENDITURE UPDATE

Spending headed higher in 2013

Capital spending throughout the U.S. power and gas sectors remains strong, driven by the need to replace an aging generation fleet, infrastructure upgrades to the transmission and distribution systems, coal-to-gas switching prompted by the economics of natural gas prices, and increasingly stringent environmental regulations. These factors, combined with utility initiatives to deploy new technologies and meet future customer demand growth, indicate that capital spending should remain elevated for the foreseeable future. An analysis of formal utility industry spending forecasts, as summarized in Graph 1 below, suggests that aggregate capital expenditure levels over the years 2013-2015, are in fact, expected to be considerably higher than previous spending levels. We note that the estimates included in this study are derived from formal company forecasts and, accordingly, reflect committed projects.





The trend toward new infrastructure investment is tied to the industry's now pervasive "back to basics" strategy – essentially investing in existing and ancillary energy businesses as a means of growing profits. After a most trying time in financial markets, stemming from intense uncertainty tied to the recession, financial measures in the group stabilized, and many companies returned to a more aggressive spending posture beginning in 2011, by initiating work on numerous new and/or postponed projects.

Much of the recent increase in spending by electric companies is tied to compliance with both a spectrum of guidelines issued by the Environmental Protection Agency (EPA) (aimed at more stringent environmental restrictions), and the ever-popular renewable portfolio requirements (resulting in new wind and solar facilities). Based on available forecasts, spending is headed substantially higher in 2013, but then drops off somewhat in the 2014 and 2015 timeframe. However, we believe capital expenditure levels will increase over time in order to comply with further governmental policy requirements. We note that over the past few years, many companies' initial capital spending forecasts for the current year have, by and large, been lower than forecasts provided at later dates. For instance, as displayed in Table 5, the average amount of spending forecasted in November 2012 for the full-year 2013 was 8.4% below the most recent forecasts. This latest instance could be due to the fact that companies now have a clearer picture of EPA guidelines and other governmental policy requirements.

In the wake of these developments, utilities have been forced to decide whether to make substantial capital investments in environmental upgrades or to retire plants. With an abundant supply of shale gas, U.S. gas prices fell to a 10-year low of $1.90 per MMBtu in 2012. Although gas prices have rebounded to more than $4, prices are still well below historic averages, and projections for shale gas reserves suggest prices will remain depressed for quite some time. As a result, many older coal plants have been slated for retirement, and many utilities have shifted from coal to natural gas to fill the capacity void. Despite the drop in sales growth throughout the economic downturn over the past several years, new capacity will still be needed to meet rising customer demand, thus exacerbating the need for increasing construction expenditures.

Furthermore, we have observed higher natural gas investment over the past year or so, as new multi-year programs are being announced for gas main replacements. Also, competitive gas operations have seen a resurgence in pipeline and ancillary services investments associated with the booming shale gas industry. Additionally, new investments are being made to comply with pipeline safety standards in the aftermath of the San Bruno accident. Overall, it appears that a fertile landscape exists for new investment opportunities at both electric and gas operations for the foreseeable future.

We note that, with the demand for electricity in a slow-growth pattern, and consumers becoming increasingly more aware of conservation opportunities, passing along capital expenditure costs to ratepayers will likely become more challenging. As a result, constructive and innovative regulatory policy will be needed in order for utilities to recover operating and capital investment costs associated with both environmental compliance and reliability needs.

With much of the new investment in the power and gas sectors over the past several years being made at the regulated utility level (and ultimately included in rate base), rate case activity has been high, compared to the early 2000s, particularly in the electric sector, as displayed in Table 1. Total electric base rate increases nationwide peaked at \$5.6 billion in 2010 (77 cases), four times the \$1.4 billion aggregate level authorized in 2007 (46 cases). In 2011, electric rate case activity declined significantly, with total authorized increases falling to \$2.9 billion (56 cases). However, in 2012, total electric rate activity and increases rebounded to \$3.1 billion (70 cases). In the gas sector, where considerably less investment is targeted, year-to-year fluctuations in the level of rate increases authorized have been greater than in the electric sector. In 2012, total gas base rate increases were \$263.9 million (41 cases), down from the peak in 2008 of \$884.8 million (41 cases). Noteworthy in our analysis of rate case activity is the trend toward lower authorized returns on equity (ROEs). Table 1 shows that average allowed electric ROEs declined from 10.97% in 2003 to a low of 10.17% in 2012, and look to be heading lower with the 12-months-ended March 30, 2013 ROE average at 10.05%. During the same period, average authorized gas ROEs fell from 10.99% in 2003 to 9.94% in 2012.

Table 1 — Base Rate Increases

	Electric			Gas		
	ROE %	Amount ($M)	# Cases	ROE %	Amount ($M)	# Cases
2003	10.97	313.8	12	10.99	260.1	30
2004	10.75	1,091.5	30	10.59	303.5	31
2005	10.54	1,373.7	36	10.46	458.4	34
2006	10.36	1,465.0	42	10.43	444.0	25
2007	10.36	1,401.9	46	10.24	813.4	48
2008	10.46	2,899.4	42	10.37	884.8	41
2009	10.48	4,192.3	58	10.19	475.0	37
2010	10.34	5,567.7	77	10.08	816.7	49
2011	10.29	2,853.5	56	9.92	436.3	31
2012	10.17	3,131.5	70	9.94	263.3	41
LTM 3/30/13	10.05	2,926.7	71	9.96	176.8	41

Source: RRA

EPA rules and emissions spending

Guidelines promulgated by the EPA, will require significantly reduced emissions from power plants. The new rules have begun to reshape the utility sector, as emissions standards and the timing of implementation are clarified. The rules have fostered a wave of new compliance strategies throughout the electric sector, including the re-working of facility exhaust systems and planned plant retirements. Companies have increasingly ramped up investment plans to comply with the tightened regulations.

The EPA guidelines, Mercury and Air Toxins Standards (MATS) and Cross-State Air Pollution Rule (CSAPR), as well as other EPA initiatives, come at a time when the industry is already heavily committed to various other investment areas: compliance with increased renewable generation requirements; transmission enhancements and replacements; a smattering of new baseload generation projects; and, distribution-related investments, including smart-metering build out programs. In addition, further obstacles complicate the recovery issue, as the economy struggles to find solid footing. As a result, some utilities will likely be challenged to comply with new requirements in a timely fashion and may have to purchase emission allowances or dispatch their coal-fired facilities less often.

On March 28, 2013, the EPA finalized updates to certain emissions limits for new power plants under the MATS. The new standard applies only to future power plants, and does not change the final emission limits for existing power plants. The updates did not change the types of state-of-the-art pollution control equipment expected to be installed, and did not significantly change costs or the public health benefits included in the rule. All coal- and oil-fired electric generating facilities will need to comply with the MATS requirements by April 16, 2015. However, the EPA provided some flexibility with the allowance of an additional year to comply for "technology installations." Additionally, a second extension-year could be granted on a case-by-case basis.

In March 2012, the EPA proposed a Carbon Pollution Standard that would set national limits on the emission of carbon dioxide by future power plants. However, in April 2013, the EPA delayed issuance of the final rule after the electric power industry objected on legal and technical grounds. The draft rule, if enacted, would limit CO_2 emissions from new power plants to 1,000 pounds per MWH. Newer gas fired plants emit approximately 800 to 850 pounds of CO_2 per MWH, so the rule presents little obstacle for such facilities. However the rule would effectively kill any new coal-fired plants, as coal plants emit an average of 1,768 pounds of CO_2 per MWH.

The CSAPR requires significantly improved air quality by reducing emissions that the cross state lines of 28 effected states. Regarding CSAPR logistics, in August 2012, a federal court order vacated the CSAPR, adding an increased level of uncertainty regarding the timing and requirements under future revisions of the rule. On Jan. 24, 2013, the U.S. Court of Appeals denied the EPA's petition for a rehearing of the decision to vacate the rule, and on March 29, 2013, the U.S. Solicitor General petitioned the Supreme Court to review the decision on CSAPR. Until the matter is finalized, the CSAPR is stayed and the 2005 Clean Air Interstate Rule remains in effect. Despite the uncertainty surrounding the CSAPR ruling for utilities, the decrease in spot and forward gas prices, combined with the low demand for power, have caused the projected cost for replacement power to fall. As a result, many utilities are looking toward coal retirements and/or retrofit decisions, including coal-to-gas conversions, in order to comply with current and pending EPA rules.

As seen in Table 2, according to the Edison Electric Institute, companies have announced plans to close 293 coal plants by 2024, representing more than 57 GW of capacity. Various other estimates call for coal plant closings aggregating to a range of roughly 40 GW to 60 GW (as much as 15% of the nation's generating capability), with most to be taken out of service over the next several years. In 2012, more than 9,000 MW of coal-fired generation was retired. Coal-fired generation has declined to less than 40% of total electric output from the historical average near 45%. Meanwhile, output from gas-fired generation is on the rise, increasing to more than 30% of the nation's total electric output versus the roughly 25% historical average. The U.S. Energy Information Administration estimates that by 2040, coal-fired generation will represent 35% of electric output, while gas-fired generation will continue to account for more than 30%; renewables contributions will also be on the rise.

Table 2 **Coal Fleet Retirements Announced**

Company	Total MW	Retirement to Occur	Units Retiring
AEP	6,326	2011-2015	26
AES	625	2011-2015	6
Alliant	1,112	2010-2018	19
Ameren	1,277	2011, 2022	7
APS	633	2015	3
Black Hills	124	2012-2014	7
Consumers	971	2015	7
Dominion	2,515	2013-2022	17
DTE	272	2010-2013	5
Duke	7,836	2011-2020	50
Dynergy	489	2011-2013	4
Edison International	1,239	2010-2014	5
Empire District	88	2018	2
EFH	1,187	2012	2
Exelon	895	2011-2012	3
FirstEnergy	3,797	2010-2015	24
GenOn	3,493	2012-2015	25
Great Plains	170	2016	1
Madison G&E	178	2010-2012	5
MidAmerican	189	2015	2
NiSource	629	2010-2012	6
NRG	1,075	2010-2014	8
NV Energy	342	2016	3
OGE	171	2010	1
PGE	601	2020	1
PPL	1,062	2015	7
SCANA	770	2012-2018	6
Southern Co.	9,954	2011-2020	4
TransAlta	1,460	2019-2024	2
TVA	3,304	2012-2019	21
WE Energies	112	2010	2
Xcel Energy	1,431	2010-2022	12
Others	2,851	2010-2022	NA
Total	**57,178**		**293**

Source: Electric Edison Institute 1/22/13

New baseload generation

The prolonged economic slowdown has quieted much of the discussion regarding new baseload generation needs. Given the increased incidence of coal plant shutdowns, considerable debate has commenced as to whether the removal of large quantities of capacity from regional grids will give the wholesale market a needed shot-in-the-arm in the form of tighter supply. System reliability concerns and fears of brownouts have also entered into plant-retirement discussions. With gas prices expected to remain low for the foreseeable future, made possible by incremental supply from new shale production, natural gas-fired facilities are expected to fill the bulk of any near-term void in baseload generation.

Despite nuclear issues raised in the aftermath of the March 2011 accident at the Fukushima station in Japan, neither SCANA Corp. nor Southern Company has swayed from their plans to construct new nuclear generation. In 2012, both companies received combined construction and operating licenses (COL) from the Nuclear Regulatory Commission (NRC) to build new nuclear plants. The new permits were the first to be awarded by the NRC in over 30 years. The two new units at SCANA's Summer station, like the two approved for Southern's Vogtle site, will use the Westinghouse AP1000 reactor design. While somewhat on the periphery at present, we expect the issue of new baseload generation to resurface over the next few years in a post-recession climate, when customer energy demand growth returns to historical patterns and utilities attempt to maintain a diversified mix of fuel.

Most data in this report has been updated to include revisions to cap ex plans through May 2013. Details for the individual 47 companies are shown in Tables 3 and 4. We note that Table 4 provides a detailed analysis of industry spending, broken down by the following categories: Generation; Electric Transmission and Distribution (T&D); Environmental; Renewables; Gas Pipeline/Storage and Distribution; and, Corporate/Other.

Category identification and disclosure continue to improve since we began issuing this study in the fall-2008. However, due to an absence of uniformity in forecasting methods and details among companies in the group, coupled with limitations caused by some incomplete or limited updates, a detailed breakdown by spending category for all companies was not possible, and we have included those companies as "below the line" in Table 3.

Additionally, coincident with the absence of uniformity with respect to spending forecasts, we note that some companies employ "accrual" accounting for forecasting purposes, which may result in a timing disconnect between projections and historical data (derived from cash flow statements and therefore done on a "cash" basis). Not all companies distinguish regulated generation from competitive generation in formal forecasts; however, the vast majority of generation spending plans under way are earmarked for the regulated arena. Regarding natural gas operations, we found that very few companies provide a clear breakdown of planned spending for utility, pipeline, storage, and distribution, and we therefore group all planned gas spending into a combined gas category in Table 4.

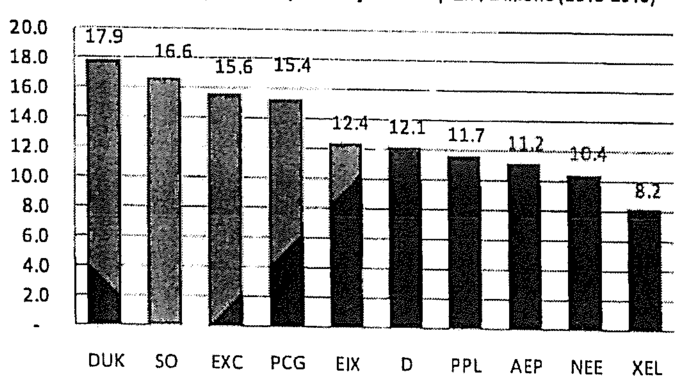
Table 5 provides the percent change in forecasts of the 47 companies, from the projected capital expenditures for 2013 as of November 2012 (reflected in the RRA Capital Expenditure Update dated Nov. 30, 2012) to the current forecast for 2013 as of May 2013.

The Top 10

Graph 3 displays a ranking of the 10 leading utilities in terms of planned capital expenditures over the three years 2013-2015. The majority of the companies in the top-10 list remain the same as those noted in our previous report. Duke Energy remains at the top in terms of total capital expenditures, as the merger with Progress Energy increased capital expenditures substantially. Interestingly, the top-10 companies, in terms of spending, are projected to account for over 51% of total capital expenditures for the 47 companies in the RRA Index over the three years 2013-2015. Also noteworthy, the California utility holding companies, Edison International and PG&E Corp, are included in the top-10 list. California has one of the most aggressive infrastructure spending programs in the nation, with major commitments planned for demand-side management, T&D, and generation.

Graph 3

Ranking-Top 10- Companies by Total Cap Ex $ Billions (2013-2015)



Source Company Estimates /SNL Energy/ RRA

Tom Serzan
Richard Ciciarelli

Table 3 Total Capital Expenditures for 47 Companies (Historical and Forecast)

	(Amount $ Millions)	2005	2006	2007	2008	2009	2010	2011	2012	Capital Expenditure Estimate 2013E	2014E	2015E
	ELECTRIC											
1	AES CORP.	828	1,480	2,425	2,850	2,520	2,310	2,430	2,236	1,380	1,285	1,900
2	ALLIANT ENERGY	538	399	542	879	1,203	867	673	1,158	835	860	990
3	AMEREN	935	992	1,381	1,896	1,710	1,042	1,030	1,240	1,540	1,738	1,738
4	AMERICAN ELECTRIC POWER*	2,404	3,528	3,556	3,800	2,792	2,345	2,869	3,025	3,578	3,800	3,800
5	CMS ENERGY	593	670	1,263	792	818	821	882	1,227	1,374	1,512	1,670
6	CONSOLIDATED EDISON	1,636	1,853	1,934	2,326	2,193	2,029	1,967	2,069	2,425	2,312	2,512
7	DOMINION RESOURCES	3,358	4,052	3,972	3,554	3,837	3,422	3,652	4,145	4,882	4,155	3,299
8	DTE ENERGY	1,085	1,403	1,299	1,373	1,035	1,099	1,484	1,820	2,175	1,879	1,761
9	DUKE ENERGY	2,413	3,470	3,216	4,533	4,433	4,855	4,413	5,507	6,088	5,713	6,050
10	EDISON INTERNATIONAL*	1,868	2,536	2,826	2,824	3,282	4,543	4,808	4,149	4,424	4,295	3,685
11	ENTERGY	1,458	1,633	1,578	2,212	1,931	1,974	2,040	2,675	2,367	2,094	2,191
12	EXELON CORP.	2,165	2,418	2,674	3,117	3,273	3,326	4,042	5,789	5,500	4,850	5,250
13	FIRSTENERGY*	1,208	1,315	1,633	2,888	2,203	1,963	2,278	2,678	2,380	2,532	2,493
14	NEXTERA ENERGY	2,546	3,739	5,019	5,236	6,006	5,846	6,628	9,461	4,565	3,235	2,570
15	GREAT PLAINS ENERGY	327	478	512	1,024	841	618	457	610	725	711	716
16	IDACORP INC.	193	222	287	244	252	338	338	240	250	288	288
17	HAWAIIAN ELECTRIC INDUSTRIES	224	211	218	282	289	182	235	325	380	500	600
18	NORTHEAST UTILITIES	775	872	1,115	1,255	908	954	1,077	1,472	1,590	1,674	1,734
19	NORTHWESTERN CORP.	81	101	117	125	189	228	189	219	280	254	237
20	NV ENERGY	686	986	1,197	1,536	843	629	621	499	515	444	480
21	OGE ENERGY	297	487	558	1,185	809	848	1,221	1,123	1,245	780	585
22	PEPCO HOLDINGS	467	475	623	643	664	802	941	1,216	1,207	1,218	1,203
23	PG&E CORP.*	1,804	2,402	2,769	3,628	3,958	3,802	4,038	4,624	5,100	5,000	5,250
24	PINNACLE WEST CAPITAL	661	738	960	936	765	748	884	890	1,121	1,033	1,188
25	PNM RESOURCES	211	321	456	345	288	281	327	309	493	586	498
26	PORTLAND GENERAL ELECTRIC	255	371	455	383	696	450	300	303	514	420	314
27	PPL CORP.	811	1,394	1,657	1,418	1,225	1,597	2,487	3,105	4,358	3,836	3,489
28	PUBLIC SRV. ENT. GROUP	1,053	1,015	1,348	1,771	1,794	2,160	2,083	2,574	2,535	2,085	1,515
29	SOUTHERN COMPANY	2,370	2,994	3,546	3,961	4,670	4,086	4,525	4,809	5,600	5,900	5,100
30	TECO ENERGY	295	456	494	590	640	490	454	505	520	775	562
31	UNS ENERGY CORP.	203	238	245	354	283	279	374	307	393	339	380
32	WESTAR ENERGY	213	345	748	937	556	540	697	810	892	803	642
33	WISCONSIN ENERGY	745	929	1,212	1,136	815	798	831	707	693	631	778
34	XCEL ENERGY	1,311	1,628	2,097	2,114	1,778	2,216	2,206	2,570	3,155	2,775	2,310
	Total Electric ($ Millions)	35,997	46,127	53,933	62,145	59,498	58,492	63,280	74,397	74,858	70,290	67,736
	GAS											
35	AGL RESOURCES	267	253	259	372	476	510	427	782	700	705	750
36	ATMOS ENERGY CORP.	333	425	392	472	509	543	623	733	780	710	735
37	CENTERPOINT ENERGY	693	1,007	1,114	1,020	1,160	1,509	1,303	1,212	1,814	1,423	1,173
38	INTEGRYS ENERGY	414	342	393	533	444	259	311	594	1,268	816	732
39	NISOURCE	590	627	787	1,300	777	804	1,125	1,499	1,815	1,589	1,573
40	ONEOK	250	376	884	1,473	791	583	1,336	1,866	2,956	1,919	1,928
41	PIEDMONT NATURAL GAS CO.	191	204	135	181	129	199	244	530	550	300	300
42	SCANA CORP.	385	527	725	904	914	876	884	1,077	1,639	1,631	1,497
43	SEMPRA ENERGY	1,377	1,907	2,011	2,061	1,912	2,082	2,844	2,956	3,300	2,340	2,340
44	SOUTHWEST GAS	294	345	341	300	217	215	381	396	340	330	330
45	QUESTAR CORP.	713	916	1,398	322	300	320	368	371	450	380	325
46	VECTREN CORP.	232	281	335	391	432	277	321	366	290	330	320
47	WGL HOLDINGS	113	160	165	135	139	130	202	251	368	381	359
	Total Gas ($ Millions)	5,853	7,371	8,938	9,464	8,201	8,287	10,369	12,632	16,068	12,854	12,362
	Total ($ Millions)	41,850	53,498	62,871	71,609	67,699	66,779	73,649	87,029	90,926	83,144	80,098

Source: SNL Energy, company surveys, and RRA adjustments.

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Table 4 — Utility Capital Expenditures by Category (2013-2015)

Companies with Segment Breakdown (Amount $ Millions)	Note	Generation 2013	2014	2015	2016	2017	% '13-'15 Total	Electric T&D** 2013	2014	2015	2016	2017	% '13-'15 Total
Electric Companies													
ALLIANT ENERGY		92	137	86	107		12%	141	152	150	152		18%
CMS ENERGY		90	141	168	183	149	9%	427	391	346	358	438	26%
CONSOLIDATED EDISON							0%	1,555	1,603	1,742			68%
DOMINION RESOURCES		2,394	1,868	1,267			46%	1,419	1,433	1,248			34%
EXELON CORP.		2250	2125	2300			43%	2,450	2,350	2,525			47%
ENTERGY	8	1,214	915	984			47%	964	984	1,010			44%
GREAT PLAINS ENERGY	4	251	232	278			35%	268	275	302			39%
HAWAIIAN ELECTRIC INDUSTRIES	3,6	38	108	130	152	152	19%	182	240	288	336	336	48%
INTEGRYS ENERGY	6	178	113	101				158	101	90			
NEXTERA ENERGY	4,8,9	1,965	1.955	1,525	1,285	1,095	53%	745	795	745	770	795	22%
NORTHEAST UTILITIES	1	30	30	34			2%	1,281	1,377	1,432			82%
NORTHWESTERN CORP.	8,7	109	112	104	100	133		67	64	64	64	64	
NV ENERGY		183	147	131	155	158	32%	225	170	195	215	244	41%
OGE ENERGY		80	75	75	75	75	9%	655	390	235	275	265	50%
PEPCO HOLDINGS							0%	1,033	1,056	1,064	1,003	1,073	87%
PNM RESOURCES	5, 7	198	165	130	173	210	31%	110	181	220	102	58	32%
PINNACLE WEST CAPITAL		453	328	423			36%	412	508	512			43%
PORTLAND GENERAL ELECTRIC	2, 6	48	43	38	39	37	10%	209	185	164	170	159	45%
PPL CORP.	4	986	645	667	875	893	19%	2,503	2,253	2,189	2,124	2,153	59%
PUBLIC SRV. ENT. GROUP	4	330	295	290			15%	1,900	1.605	1.150			76%
SOUTHERN COMPANY	4	2,700	2,500	2,000			43%	1,700	1,700	1,700			31%
TECO ENERGY	6, 7	190	275	189	189	189	35%	160	255	189	189	189	33%
UNS ENERGY CORP.	8	112	93	80	72	101	26%	185	131	179	124	109	44%
WESTAR ENERGY	4, 10	207	227	198			27%	342	295	331			41%
WISCONSIN ENERGY		141	151	163			22%	251	245	253			36%
XCEL ENERGY	4	775	630	580	590	715	24%	1.525	1.395	1 175	1.170	1.315	50%
Total - Electric ($ Millions)		14,991	13,308	11,921				20,863	20,133	19,479			
Gas Companies													
AGL RESOURCES													
ATMOS ENERGY CORP.	7												
CENTERPOINT ENERGY								720	677	557	534	512	33%
NISOURCE	8												
PIEDMONT NATURAL GAS CO.	7												
ONEOK	8												
SCANA CORP.	4	1,200	1,162	1,031			50%	218	216	270			9%
SOUTHWEST GAS	7												
QUESTAR CORP.	8												
WGL HOLDINGS													
Total - Gas ($ Millions)													
Companies without Segment Breakdown ("Below the line")*													
AES CORP.	8												
AMERICAN ELECTRIC POWER*		647						2,295					
AMEREN	7												
DTE ENERGY	8												
DUKE ENERGY	7												
EDISON INTERNATIONAL*	1, 8	578	548				9%	3,725	3,419				58%
FIRSTENERGY*	6, 8	821					11%	1,339					18%
IDACORP INC.	7												
PG&E CORP.*	7	800						3,150					
SEMPRA ENERGY	7												
VECTREN CORP.													
Total - ($ Millions)													
Grand Total ($ Millions)													

Company	Environmental 2013	2014	2015	2016	2017	% '13-'15 Total	Renewables 2013	2014	2015	2016	2017	% '13-'15 Total
Electric Companies												
ALLIANT ENERGY	355	210	200	165		28%	5	15				1%
CMS ENERGY	331	314	247	154	97	20%	31	77	153	5	1	6%
CONSOLIDATED EDISON						0%	253	95	106			6%
DOMINION RESOURCES	84	98	114			2%	73	0	0			1%
EXELON CORP.						0%	575	100	100			5%
ENTERGY						0%						0%
GREAT PLAINS ENERGY	182	149	82			18%						0%
HAWAIIAN ELECTRIC INDUSTRIES	67	58	70	82	82	13%	67	58	70	82	82	13%
INTEGRYS ENERGY	189	122	109				65	42	38			
NEXTERA ENERGY						0%	1215	220	10	5	5	14%
NORTHEAST UTILITIES	25	45	52			2%						0%
NORTHWESTERN CORP.	47	41	32									
NV ENERGY	8	30	48	15	0	6%						0%
OGE ENERGY	30	20	25	20	0	3%						0%
PEPCO HOLDINGS						0%	3	4	5	7	7	0%
PNM RESOURCES	120	193	118	52	0	27%	50	33	17	6	0	6%
PINNACLE WEST CAPITAL	21	86	187			9%	190	42	0			7%
PORTLAND GENERAL ELECTRIC	8	0	0	0	0	1%	23	28	28	1	0	6%
PPL CORP.	750	612	536	312	128	18%						0%
PUBLIC SRV. ENT. GROUP	110	105	45			4%	150	40	0			3%
SOUTHERN COMPANY	1000	1500	1100			22%						0%
TECO ENERGY	40	75	8	8	8	7%						0%
UNS ENERGY CORP.	5	23	35	50	38	6%	40	41	40	38	38	11%
WESTAR ENERGY	311	240	93			28%	4	18	0			1%
WISCONSIN ENERGY	72	0	0			3%	31	34	29			4%
XCEL ENERGY	345	235	90	15	0	8%						0%
Total - Electric ($ Millions)	4058	4355	3191				2775	848	595			
Companies without Segment Breakdown ("Below the line")*												
AMERICAN ELECTRIC POWER*	544											
EDISON INTERNATIONAL*	103	311				3%	1	2				0%
FIRSTENERGY*	125					2%						0%

Company	Gas Pipeline/Storage/Distribution/ and other 2013	2014	2015	2016	2017	% '13-'15 Total	Corporate / Other 2013	2014	2015	2016	2017	% '13-'15 Total	Total 2013	2014	2015	2016	2017	3 Year Total**** '13-'15
Electric Companies																		
ALLIANT ENERGY	151	252	475	352		33%	92	95	80	70		10%	835	860	990	845		2,685
CMS ENERGY	396	501	678	552	387	35%	99	88	78	75	85	8%	1,374	1,512	1.670	1,327	1.157	4,556
CONSOLIDATED EDISON	507	530	578			22%	110	84	86			4%	2,425	2,312	2,512			7,249
DOMINION RESOURCES	690	717	629			17%	42	39	41			1%	4,682	4,155	3,299			12,136
EXELON CORP.	225	275	325			5%						0%	5,500	4,850	5,250			15,600
ENTERGY						0%	189	195	197			9%	2,367	2,094	2,191			6,652
GREAT PLAINS ENERGY						0%	40	55	53			7%	725	711	718			2,151
HAWAIIAN ELECTRIC INDUSTRIES						0%	27	35	42	49	49	7%	380	500	600	700	700	1,480
INTEGRYS ENERGY	585	377	338				95	81	55				1,268	818	732			2,814
NEXTERA ENERGY	310	45	115	50	50	5%	330	220	175	195	190	7%	4 565	3,235	2,570	2,305	2,135	10,370
NORTHEAST UTILITIES	170	160	161			10%	84	82	55			4%	1,590	1,674	1,734			4,998
NORTHWESTERN CORP.	38	38	38	38									260	254	237	201	198	751
NV ENERGY	11	10	10	10	10	2%	89	87	85	52	70	19%	515	444	480	448	481	1,439
OGE ENERGY	455	250	205	145	130	35%	25	25	25	25	25	3%	1,245	760	565	540	495	2,570
PEPCO HOLDINGS	26	28	28	28	30	2%	145	130	108	84	87	11%	1,207	1,218	1,203	1,122	1,197	3,628
PNM RESOURCES						0%	15	14	13	13	13	3%	493	586	498	346	281	1,577
PINNACLE WEST CAPITAL						0%	45	69	66			5%	1,121	1,033	1,188			3,342
PORTLAND GENERAL ELECTRIC	161	107	33	0	0	24%	84	57	51	52	49	14%	514	420	314	263	245	1,248
PPL CORP.						0%	139	126	117	105	99	3%	4,358	3,838	3,489	3,418	3,373	11,683
PUBLIC SRV. ENT. GROUP						0%	45	40	30			2%	2,535	2,085	1,515			6,135
SOUTHERN COMPANY						0%	200	200	300			4%	5,800	5,900	5,100			16,600
TECO ENERGY	80	100	103	103	103	15%	50	70	72	72	72	10%	520	775	562	562	562	1,857
UNS ENERGY CORP.	12	14	14	15	17	4%	39	38	32	37	33	10%	393	339	380	333	334	1,112
WESTAR ENERGY						0%	29	24	20			3%	892	803	642			2,338
WISCONSIN ENERGY	192	193	325			34%	8	8	8			1%	693	631	778			2,102
XCEL ENERGY	355	365	335	325	320	13%	155	150	150	155	150	8%	3,155	2,775	2,310	2,255	2,500	8,240
Total - Electric ($ Millions)	4,364	3,862	4,390				2,160	1,971	1,947				49,210	44,678	41,623			135,311
Gas Companies																		
AGL RESOURCES													700	705	750			2,155
ATMOS ENERGY CORP.													780	710	735	820		2,225
CENTERPOINT ENERGY	894	748	616	593	590	39%							1,614	1,423	1,173	1,127	1,102	4,210
NISOURCE													1,815	1.589	1.573			4,977
PIEDMONT NATURAL GAS CO.													550	300	300			1,150
ONEOK													2,956	1,919	1,928			6,803
SCANA CORP.	157	177	124			7%	64	78	72			3%	1,639	1,631	1,497			4,767
SOUTHWEST GAS													340	330	330			1,000
QUESTAR CORP.													450	380	325			1,155
WGL HOLDINGS													368	381	359	355	339	1,107
Total - Gas ($ Millions)													11,212	9,368	8,570			29,649
Companies without Segment Breakdown ("Below the line")*																		
AES CORP.													1,380	1,285	1,900			4,565
AMERICAN ELECTRIC POWER*	92												3,578	3,800	3,800			11,178
AMEREN													1,540	1,738	1,738	1,738	1,738	5,016
DTE ENERGY													2,175	1,879	1,761			5,815
DUKE ENERGY													6,088	5,713	6,050			17,850
EDISON INTERNATIONAL*						0%	19	15				0%	4,424	4,295	3,685			12,384
FIRSTENERGY*						0%	95					1%	2,380	2,532	2,493			7,405
IDACORP INC.													250	288	288			825
PG&E CORP.*	1,150												5,100	5,000	5,250	5,250		15,350
SEMPRA ENERGY													3,300	2,340	2,340	2,340	2,340	7,980
VECTREN CORP.													290	330	320			940
Total - ($ Millions)													30,506	29,159	29,604			89,306
Grand Total ($ Millions)													90,925	83,144	80,098			264,168

Source: SNL Energy, company surveys, and RRA adjustments.

Notes to Table 4:

1 RRA estimate for proportion related to environmental and/or renewable spending

2 Maintenance and growth capital expenditure apportioned to: generation 15%, T&D 65%, other 20%

3 Spending on fuel included in generation

4 Nuclear spending included in generation

5 Includes potential capital expenditures that may not be realized

6 Capital expenditures calculated and apportioned as per RRA adjustments

7 Average shown for any range provided by the company

8 FactSet estimates for years in which company has not provided data

9 Includes only capital expenditures that have been approved by NEE's board of directors

10 Includes the potential investment for the Praire Wind Transmission joint venture

* Classification by business type unavailable for some years, resulting in "below the line" listing

** Electric T&D includes Smart Metering/AMI

Percentages of three-year total shown next to each category

Table 5	Capital Expenditures (% Change in forecast)		
Electric	Nov. 2012 Forecast for 2013	May 2013 Forecast for 2013	(%) change
1 AES CORP.	1388	1380	-0.5%
2 ALLIANT ENERGY	835	835	0.0%
3 AMEREN	1344	1540	14.6%
4 AMERICAN ELECTRIC POWER*	3600	3578	-0.6%
5 CMS ENERGY	1327	1374	3.5%
6 CONSOLIDATED EDISON	2141	2425	13.3%
7 DOMINION RESOURCES	4815	4682	-2.8%
8 DTE ENERGY	1867	2175	16.5%
9 DUKE ENERGY	5975	6088	1.9%
10 EDISON INTERNATIONAL*	4663	4424	-5.1%
11 ENTERGY	2106	2367	12.4%
12 EXELON CORP.	5300	5500	3.8%
13 FIRSTENERGY*	2620	2380	-9.2%
14 NEXTERA ENERGY	3870	4565	18.0%
15 IDACORP INC.	248	250	1.0%
16 HAWAIIAN ELECTRIC INDUSTRIES	396	380	-4.0%
17 GREAT PLAINS ENERGY	783	725	-7.4%
18 NORTHEAST UTILITIES	1575	1590	1.0%
19 NORTHWESTERN CORP.	255	260	2.1%
20 NV ENERGY	490	515	5.2%
21 OGE ENERGY	1140	1245	9.2%
22 PEPCO HOLDINGS	1198	1207	0.8%
23 PG&E CORP.*	4700	5100	8.5%
24 PINNACLE WEST CAPITAL	901	1121	24.4%
25 PNM RESOURCES	403	493	22.2%
26 PORTLAND GENERAL ELECTRIC	353	514	45.6%
27 PPL CORP.	4100	4358	6.3%
28 PUBLIC SRV. ENT. GROUP	2230	2535	13.7%
29 SOUTHERN COMPANY	4400	5600	27.3%
30 TECO ENERGY	535	520	-2.8%
31 UNS ENERGY CORP.	399	393	-1.5%
32 WESTAR ENERGY	903	892	-1.1%
33 WISCONSIN ENERGY	679	693	2.1%
34 XCEL ENERGY	3200	3155	-1.4%
Total Electric ($Millions)	70736	74858	5.8%
Gas	Nov. 2012 Forecast for 2013	May 2013 Forecast for 2013	(%) change
35 AGL RESOURCES	433	700	61.7%
36 ATMOS ENERGY CORP.	780	780	0.0%
37 CENTERPOINT ENERGY	1164	1614	38.7%
38 INTEGRYS ENERGY	1270	1266	-0.3%
39 NISOURCE	1650	1815	10.0%
40 ONEOK	1896	2956	55.9%
41 PIEDMONT NATURAL GAS CO.	550	550	0.0%
42 SCANA CORP.	1546	1639	6.0%
43 SEMPRA ENERGY	2485	3300	32.8%
44 SOUTHWEST GAS	325	340	4.6%
45 QUESTAR CORP.	445	450	1.1%
46 VECTREN CORP.	265	290	9.4%
47 WGL HOLDINGS	368	368	-0.1%
Total Gas ($Millions)	13177	16068	21.9%
Total Electric and Gas ($Millions)	83913	90926	8.4%