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FILE

PUCO EXHIBIT FILING

Date of Hearing: May 15, 2012

Case No. 10-2929-EL-UNC

PUCO Case Caption: Columbus Southern Power and Ohio Power

Volume XII

List of exhibits being filed:

Staff Exhibit 110

IEU Exhibit 121

IEU Exhibit 124

IEU Exhibit 125

IEU Exhibit 126

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Reporter's Signature: Karen Sue Gibson

Date Submitted: 5-15-12

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

\- - -

In the Matter of the :
Commission Review of the :
Capacity Charges of Ohio : Case No. 10-2929-EL-UNC
Power Company and Columbus:
Southern Power Company. :

\- - -

PROCEEDINGS

before Ms. Greta See and Ms. Sarah Parrot, Attorney Examiners, and Commissioner Andre Porter, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-A, Columbus, Ohio, called at 8:30 a.m. on Tuesday, May 15, 2012.

\- - -

VOLUME XII - REBUTTAL TESTIMONY

\- - -

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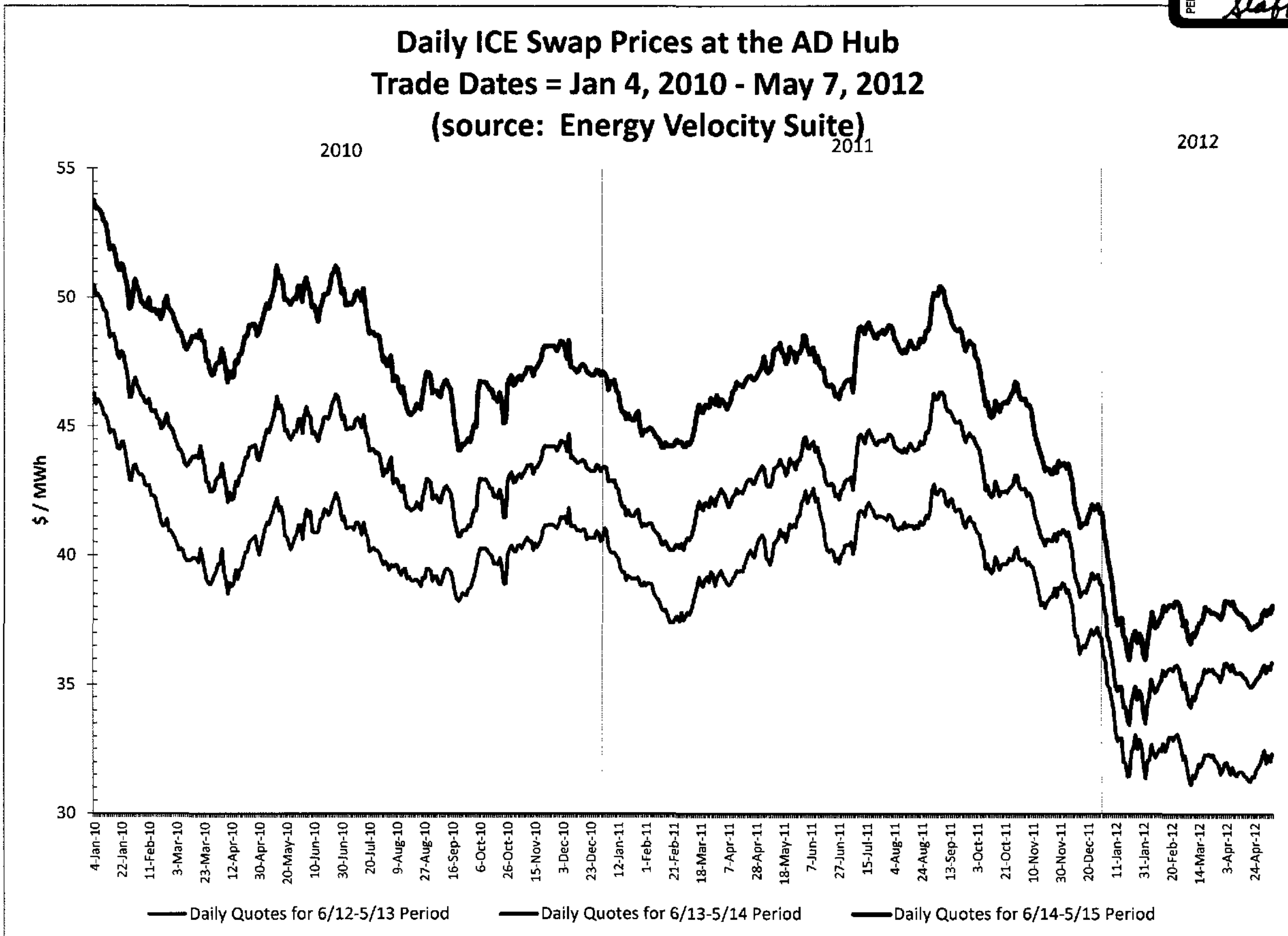
Daily ICE Swap Prices at the AD Hub
Trade Dates = Jan 4, 2010 - May 7, 2012
(source: Energy Velocity Suite)
2010
2011
2012
$ / MWh
55
50
45
40
35
30
4-Jan-10
22-Jan-10
11-Feb-10
3-Mar-10
23-Mar-10
12-Apr-10
30-Apr-10
20-May-10
10-Jun-10
30-Jun-10
20-Jul-10
9-Aug-10
27-Aug-10
16-Sep-10
6-Oct-10
26-Oct-10
15-Nov-10
3-Dec-10
23-Dec-10
12-Jan-11
1-Feb-11
21-Feb-11
18-Mar-11
7-Apr-11
28-Apr-11
18-May-11
7-Jun-11
27-Jun-11
15-Jul-11
4-Aug-11
24-Aug-11
13-Sep-11
3-Oct-11
21-Oct-11
10-Nov-11
30-Nov-11
20-Dec-11
11-Jan-12
31-Jan-12
20-Feb-12
14-Mar-12
3-Apr-12
24-Apr-12
Daily Quotes for 6/12-5/13 Period
Daily Quotes for 6/13-5/14 Period
Daily Quotes for 6/14-5/15 Period

EXHIBIT
121
IEU
PENGAD 800-631-6989

AEP AMERICAN® ELECTRIC POWER

1Q12 Earnings Release Presentation

April 20, 2012

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio due to the February 2012 PUCO rehearing order, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process, our ability to recover regulatory assets in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, a reduction in the federal statutory tax rate, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and the expected legal separation and transition to market for generation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives, our ability to successfully manage negotiations with stakeholders and obtain regulatory approval to terminate or amend the Interconnection Agreement and break up or modify the AEP Power Pool, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

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First Quarter 2012 Highlights

AEP®

- **Financial Performance**
  - Delivered GAAP and on-going earnings of $0.80 per share
  - 2012 Earnings guidance not reaffirmed
  - Remain committed to long-term strategy outlined on February 10th
- **Progress in the 1st Quarter – Moving forward with Repositioning AEP**
  - FINANCE – Issued $800M TCC Securitization bonds (March 14)
  - RETAIL – Acquired BlueStar Energy which establishes a platform for retail growth (March 7)
  - TRANSMISSION – Transco and ETT investments on-track; Transource JV with Great Plains Energy announced (April 4)
- **Ohio Regulatory Update**
  - Capacity filing hearing underway
  - ESP procedural schedule established

Dividend payout and growth rate supported by Regulated Operations

1Q12 Performance

AEP®

First Quarter Reconciliation

	EPS	Ongoing Earnings ($ in millions)
1Q11	$ 0.82	$392
Weather	$ (0.12)	
Customer Switching	$ (0.06)	
Ohio POLR	$ (0.05)	
Transmission Operations	$ 0.01	
Other	$ 0.01	
Rate Changes	$ 0.08	
Operations & Maintenance	$ 0.11	
1Q12	$ 0.80	$389

EPS Based on 484MM shares in 1Q12

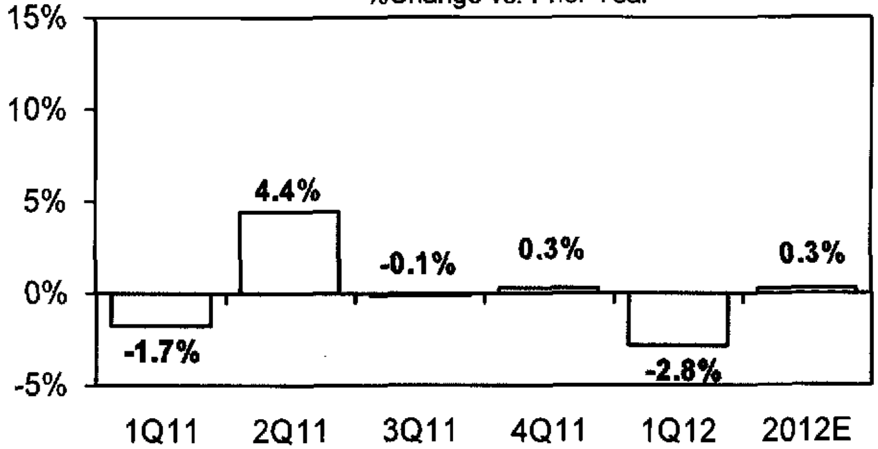
1Q12 Performance Drivers

- Weather was unfavorable by $87M vs. prior year, unfavorable $68M vs. normal
- Gross Customer Switching up $42M from prior year. Total 1Q12 retail generation margin lost $57M. As of March 2012, 28% of total AEP Ohio load lost
- Loss of POLR revenues $39M
- Transmission Operations up $5M
- Rate Changes net of offsets of $63M from multiple operating jurisdictions
- O&M expense net of offsets decreased $80M primarily due to spending discipline and reversal of a previously recorded regulatory obligation

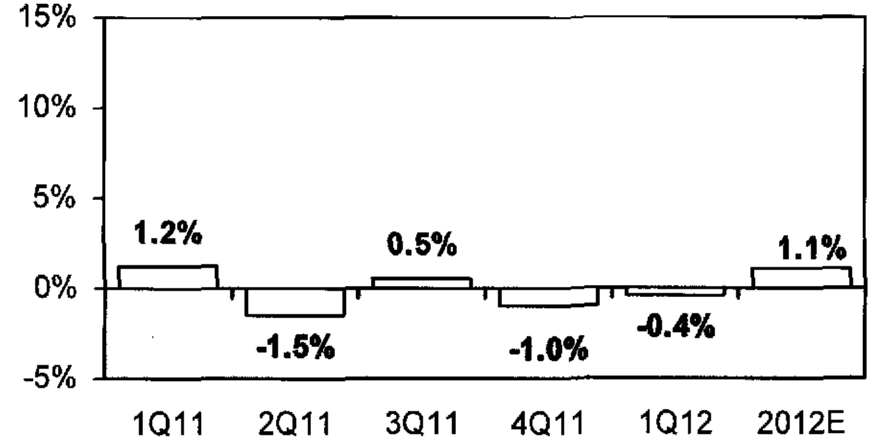
1Q12 earnings in-line with 1Q11 earnings

Normalized Load Trends

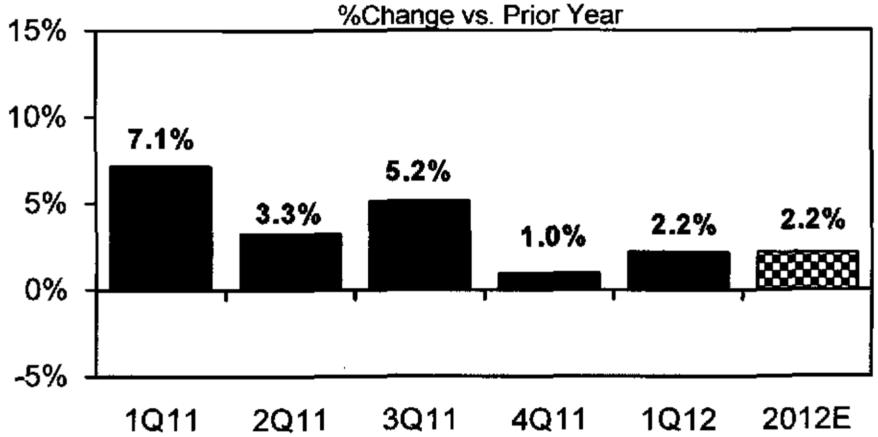
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



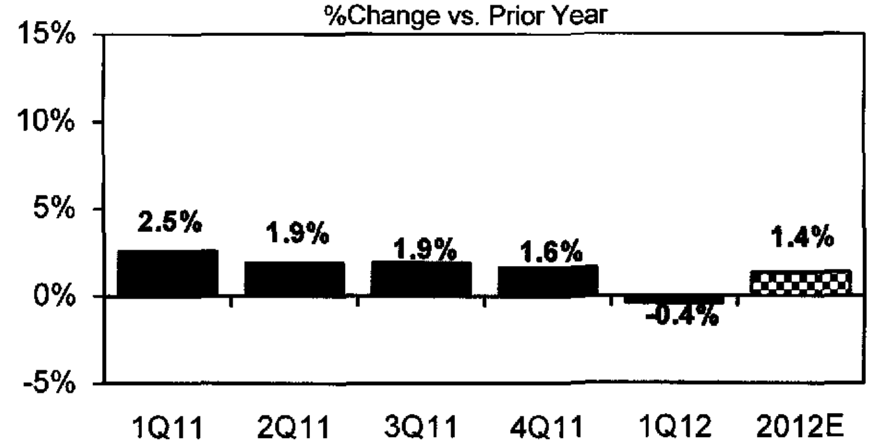
AEP Commercial Normalized GWh Sales
%Change vs. Prior Year



AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



AEP Total Normalized GWh Sales*
%Change vs. Prior Year

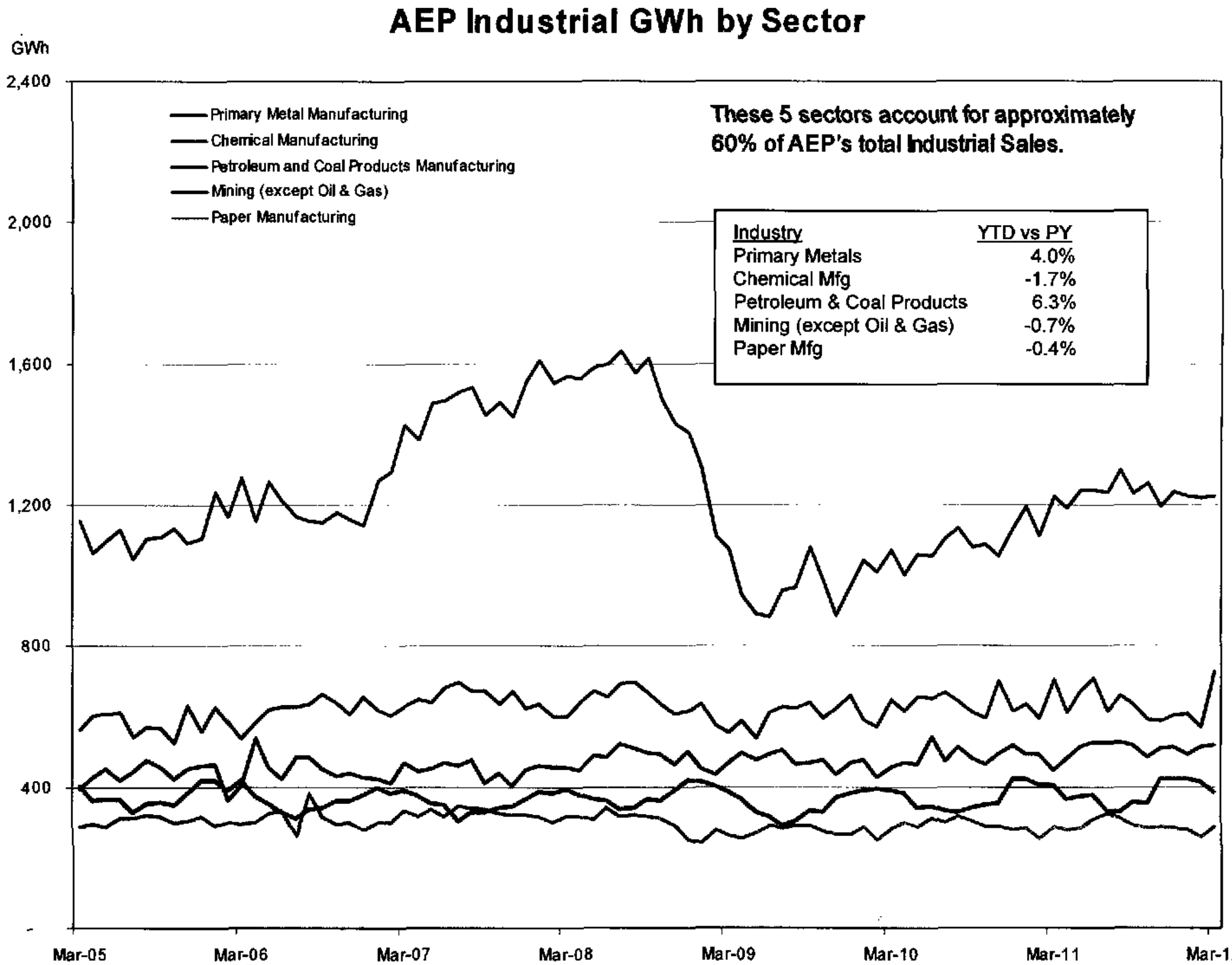


Note: Chart represents connected load

*includes firm wholesale load

Residential/Commercial sales down; Industrial sales up

Industrial Sales Volumes



Industrial sales continue to improve

Coal to Gas Switching

	Net Capacity Factor	
	1Q12	1Q11
AEP East		
Coal	47.0%	61.2%
Gas	47.3%	21.7%
AEP SPP		
Coal	75.7%	78.8%
Gas	21.9%	17.2%

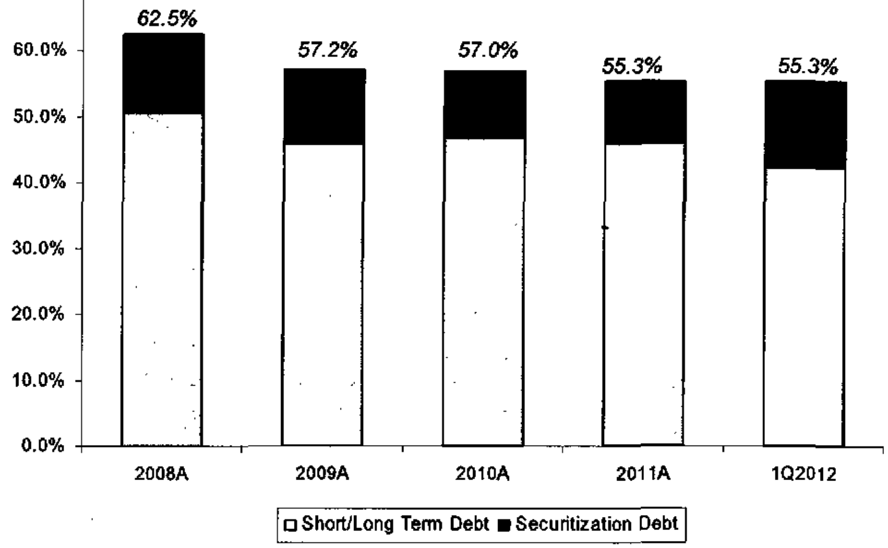
	Net Capacity Factor	
	1Q12	1Q11
AEP East Combined Cycle	77.9%	38.2%

- Natural gas consumption increased 62% 1Q12 compared to 1Q11
- Excluding Dresden, east combined cycle average capacity factor for 1Q12 was approximately 85%
- 45 days system average coal inventory at March 31, 2012
- Coal fully hedged for 2012, approximately 80% hedged for 2013

Gas switching in AEP East complete; managing coal inventories

Capitalization & Liquidity

Total Debt / Total Capitalization



Pension Funding

At the end of the first quarter AEP's pension funded status was 90%

Credit Statistics

	Actual	Target
FFO Interest Coverage	4.7	>3.6x
FFO To Total Debt	20.0%	15%- 20%

Note: Credit statistics represent the trailing 12 months as of 03/31/2012

Liquidity Summary (03/31/2012)

Liquidity Summary (unaudited)		**Actual**	
($ in millions)		Amount	Maturity
Revolving Credit Facility	$	1,750	Jul-16
Revolving Credit Facility		1,500	Jun-15
Total Credit Facilities		**3,250**	
Plus			
Cash & Cash Equivalents		286	
Less			
Commercial Paper Outstanding		(385)	
Letters of credit issued		(189)	
Net available Liquidity	**$**	**2,962**	

Strong balance sheet, solid credit metrics and adequate liquidity

AEP®

Questions

1Q12 Earnings

	$ millions			Earnings Per Share		
	1st Qtr 2011	1st Qtr 2012	Change	1st Qtr 2011	1st Qtr 2012	Change
Utility Operations	$ 389	$ 383	$ (6)	$ 0.81	$ 0.79	$ (0.02)
Transmission Operations	4	9	5	0.01	0.02	0.01
Non-Utility Operations	8	8	-	0.02	0.02	0.00
Parent & Other	(9)	(11)	(2)	(0.02)	(0.03)	(0.01)
AEP On-Going Earnings	392	389	(3)	0.82	0.80	(0.02)
Cost Reduction Initiative	9	-	(9)	0.02	-	(0.02)
Carbon Capture & Storage	(26)	-	26	(0.06)	-	0.06
Litigation Settlement - Enron Bankruptcy	(22)	-	22	(0.05)	-	0.05
[redacted]						
Reported Earnings (GAAP)	$ 353	$ 389	$ 36	$ 0.73	$ 0.80	$ 0.07

Quarterly Performance Comparison

American Electric Power
Financial Results for 1st Quarter 2012 Actual vs 1st Quarter 2011 Actual

		2011 Actual			2012 Actual	
	Performance Driver	($ millions)	EPS	Performance Driver	($ millions)	EPS
UTILITY OPERATIONS:						
Gross Margin:						
1 East Regulated Integrated Utilities	18,152 GWh @ $ 41.7 /MWhr =	757		17,018 GWh @ $ 44.9 /MWhr =	764	
2 Ohio Companies	13,305 GWh @ $ 53.7 /MWhr =	715		12,863 GWh @ $ 48.0 /MWhr =	618	
3 West Regulated Integrated Utilities	9,903 GWh @ $ 29.6 /MWhr =	293		9,657 GWh @ $ 29.9 /MWhr =	289	
4 Texas Wires	6,314 GWh @ $ 23.5 /MWhr =	149		6,157 GWh @ $ 23.5 /MWhr =	145	
5 Off-System Sales		86			84	
6 Transmission Revenue - 3rd Party		102			115	
7 Other Operating Revenue		125			101	
8 Utility Gross Margin		2,227			2,116	
9 Operations & Maintenance		(835)			(757)	
10 Depreciation & Amortization		(393)			(412)	
11 Taxes Other than Income Taxes		(209)			(211)	
12 Interest Exp & Preferred Dividend		(233)			(217)	
13 Other Income & Deductions		48			43	
14 Income Taxes		(216)			(179)	
15 Utility Operations On-Going Earnings		389	0.81		383	0.79
16 Transmission Operations On-Going Earnings		4	0.01		9	0.02
NON-UTILITY OPERATIONS:						
17 AEP River Operations		7	0.02		9	0.02
18 Generation & Marketing		1	-		(1)	-
PARENT & OTHER:						
19 Parent Company On-Going Earnings		(11)			(12)	
20 Other Investments		2			1	
21 Parent & Other On-Going Earnings		(9)	(0.02)		(11)	(0.03)
22 ON-GOING EARNINGS		392	0.82		389	0.80

Retail Rate Performance

	Rate Changes, net of trackers (in millions)
	1Q12 vs. 1Q11
East Regulated Integrated Utilities	$27
Ohio Companies	$37
West Regulated Integrated Utilities	$0
Texas Wires	$0
AEP System Total	$63
Impact on EPS	$0.08

May not foot due to rounding

1Q12 Retail Performance

AEP®

	Retail Load* (weather normalized)
	1Q12 vs. 1Q11
East Regulated Integrated Utilities	(2.0%)
Ohio Companies	(0.8%)
West Regulated Integrated Utilities	0.3%
Texas Wires	3.6%
Impact on EPS	$0.00

** Excludes firm wholesale load*

	Weather Impact (in millions)
	1Q12 vs. 1Q11
East Regulated Integrated Utilities	($45)
Ohio Companies	($24)
West Regulated Integrated Utilities	($9)
Texas Wires	($9)
Impact on EPS	$0.12

Off System Sales Gross Margin Detail

	1Q11 ($millions)	1Q12 ($millions)
OSS Physical Sales	$ 90	$ 78
Marketing/Trading	$ 32	$ 22
Pre-Sharing Gross Margin	$ 122	$ 100
Margin Shared	$ (36)	$ (16)
Net OSS	$ 86	$ 84

- Physical off-system sales margins decreased from last year by $12M
- AEP/Dayton Hub pricing: 22% decrease in liquidation prices
- Lower Trading & Marketing results by $10M

EXHIBIT
124
IEU

AMERICAN ELECTRIC POWER

Date: November 4, 2011

To: File

From: Michael Baird and Paul Pennino

Subject: ASC 360 - Cross-State Air Pollution Rule: Recoverability Test – East Fleet

I. Background

On July 6, 2011, the US Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR) which is to be implemented by January 2012. This rule replaces EPA's 2005 Clean Air Interstate Rule. The rule provides much less flexibility and fails to consider improvements in air quality that have occurred under the Clean Air Interstate Rule (CAIR), which it will replace. AEP is evaluating several compliance options to meet the emissions limits established by the CSAPR. There are numerous unresolved questions associated with the impacts of the CSAPR on the PJM system.

II. ASC 360 – Property, Plant and Equipment

A. When to Test a Long-Lived Asset for Recoverability – Triggering Event

ASC 360-10-35-21 states:

> A long-lived asset (asset group) shall be tested for recoverability whenever events or changes in circumstances indicate that its carrying amount may not be recoverable. The following are examples of such events or changes in circumstances:

- a. A significant decrease in the market price of a long-lived asset (asset group)
    - Not applicable.
- b. A significant adverse change in the extent or manner in which a long-lived asset (asset group) is being used or in its physical condition
    - Not applicable.
- c. A significant adverse change in legal factors or in the business climate that could affect the value of a long-lived asset (asset group), including an adverse action or assessment by a regulator.
    - Met.
        - Legal Factors: The implementation of the CSAPR could have a significant adverse affect on the East Fleet.

- d. An accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset (asset group).
    - Not applicable.

- e. A current-period operating or cash flow loss combined with a history of operating or cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset (asset group)

    - Not met. The units are reviewed for recoverability purposes at the East Company generation only level, where there is no issue.

- f. A current expectation that, more likely than not, a long-lived asset (asset group) will be sold or otherwise disposed of significantly before the end of its previously estimated useful life. The term *more likely than not* refers to a level of likelihood that is more than 50 percent.

    - Not met. There is no current expectation that, more likely than not, any of the units will be sold or otherwise disposed of significantly before the end of its previously estimated life.

Conclusion
Since a trigger has been met, a test for recoverability will be performed.

As cost-based rate regulated entities, APCo, KYPCo and I&M file rate cases to recover their incurred costs and as such any net cash flow projections presume the fact that costs will be fully recovered over the life of the assets. These cost-based regulated units will be included in the asset group (discussed below) and in accordance with ASC 360, any potential impairment for the APCo, KYPCo or I&M units will be evaluated if and when there is notification of potential disallowance by state regulators as provided under ASC 980 - Regulated Operations.

Since the Ohio companies generation assets are not cost-based rate regulated and do not fall under ASC 980 Regulated Operations, a recoverability test for these generating assets should be performed to determine if gross cash flows from the asset group are sufficient to recover the book value of the asset group as required under ASC 360. A discounted cash flow impairment test is necessary only if the gross cash flows fail to recover the book cost of the asset.

B. Held and Used Requirement: Test for Recoverability using Gross Cash Flows

East Pool
It is appropriate to use the East Pool as the lowest level of identifiable cash flows as described below. No other alternative courses of action to recover the carrying amount of the asset group were considered since the all of the assets are included in the East Pool.

Asset Group
An asset group is the unit of accounting for a long-lived asset or assets to be held and used, which represents the lowest level for which identifiable cash flows are largely independent of the cash flows of other groups of assets and liabilities.

In determining how to group assets at the lowest level for which there are identifiable cash flows that are largely independent of cash flows from other assets groups, we considered whether to include generation, transmission and distribution assets all in one entity level group or use the generation assets as a stand-alone asset group. Also, we considered whether to include all East operating companies together in one asset group versus just the assets of a stand-alone operating company. We considered all of the East company generation assets as the lowest level.

The non-cost based rate generation assets are not operated separately, but are coordinated and dispatched with the generation assets owned by the other East cost-based regulated operating companies (APCo, KYPCo and I&M). The costs and benefits of the generation assets are shared among all of the East operating companies in the Interconnection Agreement (Agreement). The output of the Ohio Companies' generation plants is available to fulfill the continuing native load obligations of those jurisdictions through the Power Pool Agreements. Due to the nature of electrical energy and the operation of the plants through the Pool, it is impossible to match cash inflows from the sales to cash outflows from either purchased or generated power by unit or by plant.

Based on the above considerations, the generation function group including all East companies that are part of the Agreement, is the lowest level where cash flows can be identified and are largely independent of other assets and thus is the asset group to be used in the recoverability test.

Cash Flow

Since we do not have cash flow statements by function, nor do we forecast by function, we used the attached 2011 Preliminary Long Range Plan to develop the required cash flow. The forecast reflects the capital expenditures necessary to extend the service potential of certain assets. This is inconsistent with the recoverability cash flow analysis required in ASC 360, which calls for cash flows to be based on the existing service potential of the assets at the date they are tested. To compensate for this we deducted the cash flows used for investing activities from the operating cash flows and used the resulting net cash flows to reflect the estimated cash flows achieved from the units existing service potential.

The forecast we used was for 10 years. The forecast model does not project past the 10 year period. We used the year 2020 net cash flows to estimate an additional 20 years cash flow. The use of the 2020 net cash flows was used because these cash flows are believed to be the best estimate of the forecasted cash flows due to the inclusion of significant capital expenditures to comply with environmental requirements which extends the useful lives beyond the current depreciable lives. The current average depreciable life of the Least Exposed units is 23 years; however, the model includes significant cash outflows for construction expenditure to extend the life of the plants, thus a thirty year expected useful life is reasonable. Due to immateriality to the total cash flow, the first 6 months of 2011 were not removed.

Finally, the model does not include any effect of cash from the ultimate sale of any of the plants since these plants are operated in a regulated environment and it would be anticipated that any gain would be returned to the customer.

We applied a 49.8% factor to the 2011 Preliminary Long Range Plan cash flows to estimate the cash flows from the generation function. The June 30, 2011 estimated gross margin was used because it reflects the current rates in effect related to sales other than OSS and also the over/underrecovery of fuel clause in effect in each jurisdiction. The factor represents the estimated generation gross margin for all of the East companies as a percentage of the total gross margin of the combined East companies. This approach is appropriate since the revenues and fuel expenses of the generation function are clearly identifiable on each operating company. (Note that even though the cash flows are clearly identifiable at the operating level, as mentioned previously the cash flows from each unit is dependent upon the other units in the Agreement.) The revenue is comprised of Sales for Resale (affiliated and non-affiliated) and the portion of Retail sales related to generation as described below. The fuel and purchased power expenses relate only to the generation function.

As information, the Retail sales related to generation are unbundled from the total rate charged customers in one of two ways, depending on the way the billing rates are designed. For an unbundled rate company (OPCO, CSP, APCO-VA and I&M-MI), the billing rates are entered into the MACSS system for G, T and D. Unbundled revenue reports provide the billed and unbilled revenues that support the journal entries to unbundle the revenues.

For a bundled rate company (APCO-WV, WPCO, I&M-IN, and KPCO), the various Rate Departments provide factors by rate schedule that are used to unbundle the revenues. These factors are based on rate studies and are input into the MACSS system, which generates unbundled revenue reports which are used to support the journal entries to unbundle the revenues.

A reduction was made to the cash flows for the effect of the CSPAR rules on Off System Sales. An estimated $100 million per year for 2012-2014 was made to reflect this effect. After 2014, the affected plants are forecasted to be retired.

C. Conclusion
As shown below, the estimated generation function cash flows are sufficient to recover the companies' generating assets. No further action is required.

($ millions)						
Total Company Estimated Cash Flows			East Generation Only			
10 year Forecast	20 years based on 2020	30 years (less than average remaining life of assets)	Estimated Generation 49.8% of total Revenues Less Est. CSAPR OSS Impact	Generation PP&E Balance July 2011	Excess Estimated Cash Flow versus Balance	Are Assets Recoverable?
18,843.5	51,336.0	70,179.5	34,798.8	12,528.6	22,270.3	Yes

D. Depreciation
ASC 360-10-35-22 states that if a long-lived asset (asset group) is tested for recoverability, it also may be necessary to review current depreciation estimates and method.

The plants are all being depreciated on their estimated remaining life. All of the unit's lives have been revised to reflect the NSR settlement or the most recent lives approved or filed in recent rate cases.

We are analyzing the current CSAPR rules and timelines, the related political discussions and possible outcomes in conjunction with the Ohio Settlement to determine the action to take related to the Ohio units and their related lives. As of the end of the 3rd Quarter 2011, no final decisions have been made to adjustment the depreciation lives. The current lives are appropriate given the possible outcomes.

Attachment

C: J. M. Buonaiuto
J. R. Huneck
J. H. Istvan
T. J. Festi
T. H.Ross
H. E. McCoy
D. A. Davis
O. J. Seever / J. E. Tully-Green
Deloitte

February 2008

Competitive Electricity Markets: The Benefits for Customers and the Environment

NERA
Economic Consulting

This white paper was commissioned by the COMPETE Coalition, which represents electricity customers, retail suppliers, power marketers, and generators. This paper represents the views of its authors and not necessarily the views of the COMPETE Coalition, its members, or the employer of the authors.

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List of Tables

FOREWORD

Alfred E. Kahn

Robert Julius Thorne Professor of Political Economy, Emeritus,
Cornell University
Special Consultant, NERA

Students and serious practitioners of public utility regulation have long recognized what an imperfect institution it is. Grounded in the conception that these industries are naturally monopolistic—that is, that full achievement of their inherent economies of scale requires that they be organized as franchised monopolies—it followed that they had to be regulated in order to protect consumers from exploitation, while at the same time assuring investors recovery of their prudently (more precisely, in practice, their not-demonstrably-imprudently) incurred costs.

This essentially cost-plus system appeared to work well in electric power during the quarter century following the end of World War II, when technological progress and the progressive realization of economies of scale in generation and transmission, and the adoption of nuclear generation, converged to produce declining rates in real terms. In the decades following 1973, in contrast, two bouts of double-digit inflation in the economy at large, two quadruplings of the price of oil, sharp increases in the cost of capital—especially painful in so capital-intensive a business—and massive cost overruns in nuclear facilities all compelled dramatic rate increases throughout the 1980s, just when a slump in the real prices of oil and natural gas and the advent of combined-cycle gas generation made deregulation and competition look far more attractive to consumers than continued compliance with the historic regulatory bargain.

As this brief historical account demonstrates, the movement for deregulation in the last decades of the 20th century was clearly opportunistic—putting pressures on regulatory agencies to renege on their implicit promise to set rates sufficient to provide fair returns on invested capital—a "temptation of the kleptocrats," as I put it at the time.[1] Significantly, the pressures for deregulation were most insistent in states whose electric companies had invested heavily in nuclear plants and, at the other extreme, virtually nonexistent in states still relying heavily on coal, and particularly coal-fired generating plants that had long since been totally depreciated on the companies' books.

But, clearly, there were fundamental, not merely transient issues at stake as well. As I observed some seventeen years ago, in the context of reforming regulatory practice rather than deregulation:

> [A] consistent use of current competitive market valuations, for successful and unsuccessful investments alike, would be not only unobjectionable but desirable, because it would transfer the cost of failures, symmetrically with the profits of success, from ratepayers to investors.[2]

Manifestly, genuine deregulation would produce the same beneficent result.

Deregulation alone, however, would not take into account the especial importance, in this industry—in which only limited storage of its product is possible—of reliability of supply in the face of demand that fluctuates widely. Under regulation, this reliability was secured by requiring generators to maintain some stipulated margin of excess capacity sufficient to hold loss-of-load probabilities down to some acceptable minimum—the cost of which had to be distributed among all customer groups, since all benefited from it.

It was rarely recognized, however, that such a system was itself highly inefficient, because it failed to recognize that *individual customers* have widely differing needs for such assurances, because they differ correspondingly in the ability to adapt their consumption habits to the widely varying marginal costs. Only a system that provides customers with the choice of contracting with suppliers for such assurances as each of them requires—and its corollary, able instead to alter their consumption habits in response to changes in system marginal costs—can accomplish the purpose, on the one hand, of determining what margin of excess capacity is required in the aggregate and, second, how its costs will be distributed among customers. I commend to readers the authors' exposition of how restructured markets would, by confronting customers with prices varying hourly with contemporaneous marginal costs, give them the opportunity to react in real time, thereby giving each the opportunity to choose the level of reliability he or she wants and is willing to pay for.

Just as the move to restructuring was opportunistic, so too is the current sentiment to return to regulation a reaction to transient developments—in particular, the sharp increase in oil and gas prices—driving marginal costs above historic costs. But the choice of system should not be based, opportunistically, on transient events: the real defect of regulation is that rates set under it are based necessarily on averages—over time and among groups of customers. Ideally, the system would confront each customer with the proper price signals. And production efficiency is best realized when investors bear responsibility for investment decisions.

Policy makers confronting pressures to undo the restructuring of the electricity industry would be well advised to base their decisions on the longer-term benefits that will flow from properly implementing competitive markets, rather than on adventitious circumstances driving market prices temporarily above or below regulated rates.

Endnotes:

1. Alfred E. Kahn, *Letting Go: Deregulating the Process of Deregulation, or: Temptation of the Kleptocrats and the Political Economy of Regulatory Disingenuousness* (Institute of Public Utilities and Network Industries, Michigan State University, 1998).

2. Alfred E. Kahn, "The Changing Focus of Electric Utility Regulation," *Research in Law and Economics*, Vol. 13, p. 223 (1991)

Alfred E. Kahn

I. EXECUTIVE SUMMARY[1]

State policy makers are reviewing past decisions to promote competition in electricity markets and, in some cases, are debating whether to reverse course. Competitive electricity markets, also known as "restructured electricity markets," refer to the organization of the electric industry in states where utilities no longer have the obligation to plan and build generating capacity, and have often divested generation ownership. The purpose of this paper is to present an objective review of both traditional regulation and competitive electricity markets in order to assist policy makers as they critically assess their policy options.

The end of transition periods featuring rate caps and the onset of market-based retail rates has resulted in price increases for some states. While many have attributed these price increases to a failure of competition, the timing of the price increases is a coincidence and does not equate to causality. Electricity prices, driven by fuel costs, have risen in all states, not just those that restructured their electricity markets. As a result of these price increases, some states are examining their experiences with electric industry restructuring.

Prices derived by competitive markets and rates derived by traditional regulation[2] are fundamentally different, and will produce different outcomes. Over time, competitive markets are widely held to produce the most efficient results in our economy, providing the lowest costs to customers. Markets reward innovation—the search for and discovery, development, adoption, and commercialization of new products, services, organizational structures, processes, and procedures—that meets market demand. In a competitive environment, customers have more control over what they consume and what they pay, price levels will encourage more efficient use of energy, and market prices will encourage more demand response. Economists and experienced regulators, as well as national electricity policy, favor reliance on competitive markets when workable competition is feasible. It is important to evaluate the attributes of the competitive and cost-based regulatory models, and to critically analyze the strengths and weaknesses of each.

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[1] This white paper was prepared primarily by Eugene T. Meehan, a Senior Vice President at NERA, with Wayne P. Olson, a Senior Consultant at NERA. We thank Joshua Rogers for his research and editorial help. The opinions expressed herein are solely attributable to the authors and do not necessarily present a view of the firm or of other NERA professionals.

[2] Traditionally regulated utilities have an obligation to serve under traditional cost-of-service regulation, and to make and implement long-term generation plans in order to provide efficient, safe, adequate, and reliable service over time. It is important to note that even in restructured states, where such a model has been abandoned, there are many residual elements of traditional regulation. Transmission and distribution delivery service prices are regulated, and while customers receive a market-based generation price, the market procurement method is regulated.

Competition facilitates the most efficient means of production. Competitive market pricing provides significant benefits not found under traditional regulatory pricing. Among these benefits are the following:

- Market-based price signals are transparent and can stimulate appropriate infrastructure investment, energy conservation, and demand response.
- Competition provides customers with choices—i.e., customer sovereignty. Customers can exercise their own choices with respect to long-term risks, environmental concerns, and even reliability levels.
- Competitive market pricing allows sellers to tailor products and services to their customers' needs, and use demand-side solutions to avoid supply-side investment where appropriate.
- By pricing at market, prices will be similar for proximate utilities.
- Competition shifts risks from customers to investors.
- Competition produces more efficient results because the investor, not the ratepayer, assumes the generation investment risk.
- In competitive markets, poor producers fail and are acquired or replaced by those with more skill, foresight, and industry.

The electric utility industry pursued competition not for academic reasons, but because regulation was producing unacceptable outcomes, including large price differences between proximate utilities, large plant cost overruns, rate shocks and phase-ins, and customer dissatisfaction with lack of control over their electricity costs. Some innovative pricing concepts were studied, but they were rarely implemented on a large scale, and offerings were limited to a few standard tariffs. New generation built under regulation was considered too risky by both customers and investors, and power plants, particularly nuclear generators, demonstrated poor operating performance.

The differences between cost-of-service regulated rates and prices derived from competition are predictable and certain, and include the following:

- Regulated rates are founded on utilities' and regulators' judgment about the attributes of the product (e.g., reliability, environmental impacts) rather than the discipline of market forces.
- Regulated rates result in utilities and regulators imposing their choices on customers.
- Cost-based regulation makes it difficult for customers to make choices based on their own preferences and responses to market price signals.

- Cost-based regulated prices distort price signals necessary for efficient consumption, and undermine incentives for conservation and demand response. This creates a need to develop complicated and expensive conservation programs that "correct" the price signals through administrative means, when efficient results are obtained with simpler programs and market-derived prices.

Before undoing competitive markets, either intentionally or inadvertently, policy makers should consider the following facts:

- Regulated-monopoly generation imposed huge cost burdens on customers. These burdens, to which customers were exposed under the last significant non-gas capacity expansion, are what led many "high cost" states to restructure. In many states, cost-based regulation failed to produce reasonably priced electricity in the 1980s.

- States continuing with the regulated monopoly model are providing, and must continue to provide, iron-clad cost recovery guarantees for new generation investment.

- Transparent market prices derived in competitive markets are encouraging penetration of energy efficiency (conservation) and facilitating responsive consumer demand, lowering investment needs and providing environmental benefits.

- Innovations in end-use efficiency can potentially be created when customers control their own choices based on available information, and the market provides creative solutions. This can happen to the full extent only in a competitive market.

- Competitive electricity markets have led the way in developing renewable generation.

- Recent price increases are largely driven by fuel price increases, and have occurred in both competitive and traditionally regulated states.

While the promotion of competitive markets may not have been implemented perfectly, the points above suggest that customers would be better served by regulatory efforts directed at refining and improving the competitive model, rather than returning to cost-of-service regulation.

II. INTRODUCTION

Over $400 billion of electric industry infrastructure investment in generating plants will be required between 2006 and 2030.[3] Investments will be needed not only to accommodate the growth in population and the economy, but to replace aging facilities,[4] reduce emissions, fund research and development of innovative technologies, and lessen dependence on the use of liquid fuels from politically unstable foreign sources. In addition, all of these factors must be viewed in the context of heightened interest in renewable energy.[5] With such a large investment at stake, efficiency must be maximized and customers' interests must be protected. A failure to make this investment in the most efficient manner will: (1) make it difficult to ensure affordable and reliable electricity supply; (2) threaten the global competitiveness of the United States; and (3) risk having the country fall short of achieving environmental objectives.

To induce the needed investment, two economic models—that are markedly different both in terms of how they work and the incentives that they provide—can be used. The first is competition. In competitive markets, investors evaluate alternatives, make investment decisions, and place their capital at risk to market forces. Poor investment decisions lead to investor losses, even if such decisions were reasonable at the time they were made. The second model is cost-of-service regulation. In traditionally regulated markets, decisions about the type and timing of generating plant additions are generally determined by utilities, which are overseen by utility regulators. A utility builds, owns, and operates its system subject to oversight by the regulator through an open process that allows for significant input by stakeholders. While utility investors assume a limited set of investment risks, customers assume more, as they ultimately fund and support the investments through the rates they pay. Customers typically bear the risk when the selected investment incurs relatively higher costs, leading to rates that exceed market levels—so long as the utility's actions were prudent, meaning the actions were reasonable given available information.

At the national level, electricity policy is clear. Federal law provides for competition in wholesale generation markets and open access to transmission facilities. While this policy accommodates wholesale competition, it does not mandate or promote competition at the retail level. States have the choice to rely on vertically integrated utilities to plan, build, and own generating plants; to require utilities to use their monopoly position to underwrite long-term contracts that provide cost recovery without regard to how costs compare to the market in the future;[6] or, to transfer the responsibility for investment decisions and the risk of investment

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3 "[T]otal of 258 gigawatts of new [generating] capacity is expected between 2006 and 2030, representing a total investment of approximately $412 billion (2005 dollars)," *Annual Energy Outlook* 2007, Energy Information Agency, DOE/EIA-0383, 2007.

4 In the Northeastern US, about 41,000 megawatts of generation capacity are due to be retired, which is about one-quarter of generating plant in the region. *See*: Hugh Wynne, *U.S. Utilities: Capacity Retirements, Generation Investment and Technology Choice*, Bernstein Research, August 2006.

5 Over the next five years, renewables comprise about 16 percent of the new generation that has been proposed; wind comprises 88 percent of proposed renewables. *See*: Dan Ford, *Just the Beginning*, Lehman Brothers (Power & Utilities), August 21, 2006, p. 8.

6 The key phrase here is "in the future." Regulated monopolies have to reasonably plan in this day and age, but the standard by which they are judged is whether their decisions were reasonable based on what a prudent utility

decisions away from customers and on to investors by adopting a competitive model. These state decisions on whether to use cost-of-service regulation, competition, or some mix of the two are critical to achieving efficient investment, promoting environmental goals, and protecting customer interests.

Choosing between competition and cost-of-service regulation is not easy. It can be difficult to fully appreciate the consequences of these two options. Given the long-lived nature of utility assets, the choice will have long-term financial and environmental consequences for energy customers. The United States, with its federal system of government, is unique among nations in reserving this major economic choice for the individual states. Policy makers undoubtedly face difficult challenges in the current environment, with price increases largely driven by input price increases, which have little to do with whether or not there are competitive power markets in the state.

management could have known at the time. If, in the future, the regulated utility's costs become uneconomic relative to the market price, the utility would still be able to recover its actual, prudently-incurred costs in rates.

III. THE CHOICE BETWEEN TRADITIONALLY REGULATED AND COMPETITIVE MARKETS IS CLEAR

Under competition, prices reflect the supply and demand conditions at the time, and customers have the ability to choose products and services that allow them to manage their individual electricity usage. Under cost-of-service regulation, customers enter into an ongoing long-term contract to support new generating investment through their local utilities, and have very little product choice. Prices reflect historical costs and historical investment decisions, not prevailing market prices.

Competitive market pricing provides many benefits not found under traditional regulatory pricing. First, because investors are compensated based on the market and not cost, they bear the risks and rewards of generation investment. Second, price signals are more accurate within competitive markets, and can stimulate appropriate infrastructure investment, energy conservation, and demand response. Markets use these price signals to evaluate solutions to current and future energy challenges. Third, competitive market pricing allows sellers to tailor products and services to their customers' needs, and use their ability to respond to prices in a way to avoid new investments where appropriate. Lastly, by pricing at market, prices will be similar for proximate utilities. Consequently, industries located in different utility territories will not be subject to arbitrary cost disadvantages relative to competitors, a balance that represents a change from cost-of-service regulation. Under the latter, if one utility decided to build a nuclear plant that resulted in a large but prudent cost overrun, while the neighboring utility decided on a coal plant that was built within budget, rates for the two utilities could differ sharply. This is not typical of functioning markets, and it is difficult for customers, particularly industrial competitors, to accept such arbitrary pricing.

Regulated prices are based on cost of service, and to the extent that different utilities make different investment decisions, prices for proximate utilities may be very different. Throughout the 1980s and 1990s, regulated prices were far above market. Once gas prices declined and technology developments in combined cycle generation lowered cost and heat rates, the cost of nuclear investments and Public Utility Regulatory Policies Act of 1978 (PURPA) qualifying facility (QF) contracts exceeded the cost of constructing and operating new combined cycle plants, or taking advantage of surplus capacity. Prices charged by proximate utilities differed based on the timing of their plant additions and construction cost outcomes.

Luck played a large factor in determining the rates that particular electricity customers paid. But one thing is certain: the major driver for the move to competitive electricity markets in the 1990s was the series of poor outcomes that occurred during the 1970s and 1980s, when the inclusion of "lumpy" investments in nuclear generating plants led to concerns about "rate shock," rate increase, phase-in plans, and automatic pass-through of fuel costs. Ratepayers and investors shared in the financial burden resulting from these investment decisions.[7]

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[7] The economic losses resulting from the mistakes of the 1970s and 1980s may have cost as much as $100 billion. *See*: Wald, "Nuclear Plant Drain Put at $100 Billion for U.S.," *New York Times*, February 1, 1988, p. D1. This article was cited in Richard Goldsmith, "Utility Rates and 'Takings,'" *Energy Law Journal*, Vol. 10, No. 2, 1989, p. 241.

There is little reason to believe that a return to traditional regulation would lead to prices that would be continually below or at market levels. The only assured outcome is that cost-of-service regulated prices will reflect historical costs, not the market. Regulated prices could be administratively set to be relatively stable, but this may come at the cost of consistently failing to reflect the actual costs incurred. It makes little sense to attempt to choose between a traditionally regulated and a competitive model based on expectations of future price level differences, as such a choice would be speculative.

In competitive markets, where larger customers face hourly market prices (and smaller customers may elect to do so), electricity providers in many instances offer creative packages to satisfy customers. These are tangible differences between the traditionally regulated and competitive models that are predictable and certain. It is also certain that under competition, customers will have more control over what they consume and what they pay, that price levels will become known and encourage more efficient use of energy, and market prices will encourage the development of more responsive demand. Moreover, the same benefits apply to supply as well as to demand alternatives. For example, in a traditionally regulated model, wind resources will be viable only to the extent that a utility chooses to build or buy wind. In a competitive market, wind developers will have access to regional transmission organization (RTO) transmission and integration service, and will see market incentives to develop projects that provide maximum market benefits. Correspondingly, consumers may elect to buy more energy from wind and other renewable resources.

In competitive markets, generation investment decisions are made by investors in response to customer needs. Investors bear the risk of those decisions. This is a fundamental and important difference between competitive markets and cost-of-service regulation. It is important to consider that bearing risk does not equate to simply absorbing losses. There is an upside and a downside to risk. In return for bearing losses on unsuccessful investment decisions, investors realize gains on successful investments. That is the competitive model that prevails throughout the US economy.

There are other differences between cost-of-service regulation and competition that are predictable and certain. For instance, regulation requires utilities and, in turn, regulators, to substitute their judgment about the attributes of the product (e.g., reliability, environmental impacts) for that of the market, and this makes it difficult for customers to make choices based on their own preferences. Competition gives customers greater choice and control through market-based innovation. Customers can exercise their own choices with respect to environmental attributes, long-term risks, and even reliability levels. Regulated prices also typically distort price signals that are necessary for efficient consumption, and undermine incentives for conservation and demand response. Since the mid-1970s, traditionally regulated utilities have investigated innovative pricing and demand control. Progress has been limited, as regulated tariffs are standard and creative pricing schemes reflecting individual circumstances are hard to implement.

IV. ELECTRICITY COMPETITION WAS PURSUED AS A SOLUTION TO LONG-TERM PROBLEMS

Policy makers should consider that electricity markets were restructured because regulation was producing high prices and generally unacceptable outcomes for both customers and shareholders. This section will explain the cost-of-service regulation problems that began in the mid-1970s, which include price differences between proximate utilities, plant cost overruns, rate shocks and phase-ins, PURPA excess costs, and customer dissatisfaction with the lack of control over their electricity costs. Power plants, particularly nuclear plants, demonstrated poor operating performance.[8] Demand side measures and innovative pricing were frequently discussed but rarely implemented successfully in the traditionally regulated environment. By the mid- to late-1980s, there was substantial dissatisfaction with the outcomes of the regulatory process, which led policy makers to pursue competition in the 1990s.

These well-known regulatory problems, which began in the mid-1970s, created a strong impetus for the industry to restructure. A significant component to the problems was price, which, as Professor Paul Joskow of MIT notes, "reflected the high capital costs and poor operating performance of nuclear power plants commissioned during the 1970s and 1980s, the high prices reflected in PURPA/QF contracts, and the costs of excess capacity which got rolled into regulated prices."[9] It is reasonable to assume that the same or similar problems could arise in states that revert to a system akin to traditional regulation. Problems with traditional, cost-of-service regulation of generation are still relevant in many parts of the United States.

US power systems were, for the most part, developed by vertically integrated utilities. These utilities built, owned, and operated distribution, transmission, and generation facilities. Traditionally, these utilities had exclusive service territories and the right to exclude other entities from the use of their distribution and, to a lesser extent, transmission facilities. The generation investment by these utilities was made pursuant to an obligation to serve all loads in the service territory. The legal framework provided for the right to charge rates that allowed the utility a reasonable opportunity to recover all prudent investments and costs incurred to meet that obligation, and further protected that investment with an exclusive service territory and the right to exclude others from the use of distribution facilities.

Major nuclear plant cost overruns received a large amount of press in the 1970s and 1980s. Regulators no longer wanted to deal with overseeing ratemaking issues years after an investment had been made in a plant. To cite some examples:

- In Ohio, construction of the Zimmer nuclear power plant began in 1969, with an estimated in operation date of 1975. Cincinnati Gas & Electric, Dayton Power & Light,

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8 Statistics show that there has been substantial improvement in nuclear operating performance in recent years. This is most easily represented by the increase in average capacity factor across the US nuclear power industry. The Nuclear Energy Institute provides public access to these statistics on its website. Please *see*: http://www.nei.org/resourcesandstats/nuclear_statistics/usnuclearpowerplants/ (Accessed 11/28/07).

9 Paul L. Joskow, *U.S Energy Policy During the 1990s*, prepared for the conference "American Economic Policy During the 1990s," sponsored by the John F. Kennedy School of Government, Harvard University, June 27 to June 30, 2001.

and Columbus and Southern Ohio Electric made up the ownership group, which predicted that the total cost of construction would be $240 million. There were massive cost overruns after construction began, and the estimated total cost rose to $3.5 billion, while the operating date became uncertain. Following allegations of mismanagement and intervention by the Nuclear Regulatory Commission, the owners announced that the plant would be converted to a coal-fired unit with an estimated completion date of 1991 at an additional cost of $1.7 billion.[10]

- In Michigan, construction of the Midland nuclear power plant was expected to be completed by 1975 at a cost of $276 million. Instead, construction of the plant was halted in 1984, after total costs had risen to $4.2 billion. In 1986, the Michigan Public Service Commission decided that the plant should be converted to a gas-fired unit, with a conversion cost of $600 million.[11]

- In New York, construction of the Nine Mile 2 plant began in 1970. The total cost for this project was initially estimated to be under $400 million, and the facility was projected to be operating by 1977. These estimates changed dramatically after construction began, with total costs reaching $3.7 billion and a completion date of 1986. The total cost of the plant after completion in 1986 was $5.4 billion, of which $4.45 billion was deemed recoverable by the New York Public Service Commission.[12]

There are many other examples of cost overruns, which led to a great deal of regulatory frustration over how to better deal with the construction and financing of generation. These frustrations stemmed from problems with nuclear power plants that experienced huge cost overruns, the aftermath of the energy crises of the 1970s, sharply reduced electricity demand growth rates, and the basic fact, that under the traditional regulatory compact, customers bore the vast majority of the risk.

In response to the regulatory issues, state regulators began to emphasize long-term "integrated resource planning" (IRP), which sought to improve on traditional *ex post* regulation by adding an *ex ante* component.[13] IRP began with the best of intentions—to do utility regulation "right," before the fact. Some regulators decided to use a forward-looking regulatory planning process in an attempt to acquire the least costly resources. At the same time, there was a redoubled emphasis on *ex post* scrutiny of the prudence of generation construction programs before new plants were allowed into the rate base.

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10 Charles F. Phillips, Jr., *The Regulation of Public Utilities* (Arlington, VA: Public Utilities Reports, Inc., 1988), pp. 33-34.

11 *Id.*

12 Leonard S, Goodman, *The Process of Ratemaking* (Vienna, VA: Public Utilities Reports, Inc., 1998), pp. 866-867.

13 Paul Joskow points out that PURPA was "accompanied by the creation of public 'integrated resource planning' (IRP) or 'least cost planning' (LCP) processes to determine 'appropriate' electric utility investment and contracting strategies which were eventually implemented with competitive bidding programs .... The rationale for and economic consequences of these programs were controversial." Joskow, *supra* note 9.

By the late 1980s, many utilities that needed new generation supply were required to procure this supply through competitive bid processes and IRPs. By 1990, 27 states had mandated or allowed the use of utility competitive bidding processes for generation resource procurement.[14] Utility participation in these bidding processes depended on state policy. In some cases, they were required to bid through an affiliate, submitting either a fixed-price bid or a proposal to build a rate-base generating facility, where the costs were not fixed. In either case, they would need to justify the selection of the winning bid to the regulator, and they were competing against non-utility providers.

Under traditional regulation, whether generation was built by the utility or by a new entrant, long-term commitments at ratepayer expense were provided to support the construction of long-term generating assets. If built by the utility, the assumption was that the asset would stay in the utility rate base until it was no longer used and useful, which could be 30-50 years. If built by an independent power producer under PURPA, with pricing based on avoided cost (the cost that the utility avoided by building the generation resource itself), the utility was frequently required to sign a long-term contract—sometimes as long as 15 to 30 years—to support the resource. Moreover, counter-party risk was not always adequately recognized, so the decisions that regulators made as part of the IRP process had major ramifications for utilities, new entrants, and electricity users over very long periods of time.

In addition to nuclear cost overruns, PURPA contracts were also burdening customers. As an example, Regulatory Research Associates notes that "[o]n March 10, 1997, NMK and 19 IPPs announced that a Master Restructuring Agreement was reached 'in principle' to restructure or terminate 44 purchased power contracts" and that "under the MRA, NMK would restructure or terminate the 44 power contracts in exchange for approximately $3.6 billion in cash and/or debt securities and 46 million common shares, representing about 25% of NMK's outstanding common shares."[15]

The experiences of the past are especially relevant today. Plant construction costs have escalated sharply as more utilities are adding generation, making it more important than ever that existing resources be used efficiently, and that demand response and energy efficiency programs be pursued when it is economical to do so. The expected cost of building a new nuclear plant, for example, is escalating as a result of "massive inflation in copper and nickel and stainless steel and concrete."[16] Part of the reason for the 25%-30% increase in the estimated cost of a coal-fired plant is the "huge price increases for the raw materials that plants are made from, including copper and nickel," as well as the cost of finishing those commodities into components.[17] Electricity prices are increasing and, just as in a competitive market, regulation does not shield

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[14] Steven Ferrey, *Law of Independent Power* (Deerfield, IL: Clark-Boardman, 1996), p. 9-3. Ferrey cites the National Independent Energy Producers, "Bidding for Power: The Emergence of Competitive Bidding in Electric Generation," March 1990, p. 11.

[15] Regulatory Research Associates, Inc., *Regulatory Focus – Niagara Mohawk Power Final Report*, April 23, 1998.

[16] *See*: Matthew L. Wald, "Costs Surge for Building Power Plants," *New York Times*, July 10, 2007.

[17] *Id.*

customers from rising input costs. Though costs may be deferred for a period of time due to the regulatory process, they will be recovered so long as they were prudently incurred.

V. COMPETITION HAS CLEAR ADVANTAGES OVER TRADITIONAL REGULATION AND HAS ALREADY BEGUN TO PROVIDE EFFICIENCY AND ENVIRONMENTAL BENEFITS

Competitive electricity markets allow consumers to choose among providers and service options. This combination of open entry for suppliers and choice for customers provides the benefits of competitive markets (e.g., efficient resource allocation, accurate price signals, and incentives for innovation) and limits competitors' ability to exercise market power. Customers are protected from open-ended commitments to pay above-market costs that would not be passed through in a competitive market. This does not mean that entry into markets will be costless or easy, but rather that all actual competitors, incumbents and new entrants alike, will have made (and potential competitors could make) the investments and commitments necessary for them to compete in the market. Under this system, customers are free to manage long-term risk, which, for example, could include entering into long-term contracts with electricity suppliers.

Under traditional regulation, vertically integrated utilities build new generating plants in order to serve customer demand. Through the regulatory least-cost planning process, utilities are given permission to pursue resource procurement strategies, which effectively commit the regulator to pass the resulting costs through to customers so long as the utility has acted prudently in incurring those costs. This type of utility regulation includes both: (1) an *ex ante* component, requiring the utility to use least-cost integrated resource planning, and to get permission from the regulator before it commits to build or purchase new generating resources; and (2) an *ex post* component, requiring the utility to ask for a rate increase that puts the new plant into the rate base, and allows it the opportunity to earn its opportunity cost of capital on that rate base. Given the utility's obligation to serve, there is a corresponding regulatory obligation to pass through prudently incurred costs to customers, regardless of what those costs would have been in a competitive market.

Table 1 includes a listing of significant differences between firms that operate in competitive and traditionally regulated models that policy makers should consider when deciding how to move forward.

Table 1: Competitive Versus Traditionally Regulated Markets

	Competition	***Traditional Regulation***
Funding	Company funds investments with the expectation that it will be able to charge customers prices that justify those costs.	Ratepayers fund prudently incurred investments in rate base with a virtual certainty of recovering the costs.
Price Determination	Prices set in a market by supply and demand with open-ended possibilities for pricing structures, which means choice for consumers.	Prices set based on cost with limited menu of regulated tariffs.
Market Concentration	Multiple firms compete with one another, with potential competitors providing competitive pressure as well.	Generally one firm, once with a franchise.
What Is Built	Companies, in response to customer demand, will be more likely to invest in less traditional and more energy-efficient forms of generation, including renewables.	Regulators approve what utilities build. This may or may not be the lowest cost investment, and may or may not be technologically innovative.
Capital Structure	Less use of leverage perhaps, reflecting greater investment risk, but more potential for innovative financing arrangements.	Traditional utility regulation accommodates the use of more debt, but limits innovation.
Who Bears Risk of Bad Investments?	Investors.	Consumers.
Market Activity	The competitive environment is dynamic and subject to entry and exit. This creates a powerful incentive for firms to increase operating efficiency.	Static. Subject to bureaucratic process.
Cost Allocation	Value branding. Independent power companies have a greater opportunity to market different services to different customers.	Cost averaging. Through the regulatory process, costs incurred are averaged out when determining rates, and the ratepayers that incur specific costs may not necessarily pay for them.
Keys To Success	Ability to compete on price, terms, and non-price attributes such as billing arrangements and product innovation (such as green power).	Prudence and accountability in decision making; competence working with regulatory and political policy. Ability to overcome market failures.
Vertical Integration	Greater vertical separation of regulated and competitive activities.	Typically vertically integrated, subject to an internal system of command.
Ownership And Investment	Risk and return expectations will be relatively higher. This will affect what types of entities hold ownership stakes.	Risk and return expectations will be relatively lower. This will affect what types of entities hold ownership stakes.
Marketing	Increased need for marketing, and development of innovative products. Focused on meeting individual customer needs through innovation.	Reduced need for marketing and business development. Largely focused on providing one-size-fits-all solutions for customers.
Price Stability	If price stability is desired by customers, competitive retailers will make such a product available.	The regulatory process eventually allows recovery of all prudent costs. Rates can be slow to respond to changing conditions due to regulatory lag.
Price Signals	Prices tend to reflect marginal costs, the most accurate representation of opportunity cost.	Retail prices can become distorted from marginal costs through the ratemaking process.

This table demonstrates the disparate characteristics of competitive and traditionally regulated markets. The fundamentals of a competitive market, such as having more than one supplier, feasible entry and exit, and enhanced price transparency, create these differences. These factors allow competition to spur reductions in operating expenses and increases in innovation.

Traditional regulation, although based on prudently incurred costs, can yield inefficient results, primarily due to the requirement that utility ratepayers bear the majority of risks, rather than investors.

A. Competition Shifts the Risk to Investors

One of the benefits of restructured markets is that the investment risk for generation plants is shifting from consumers to investors. For instance, after restructuring, there was a huge initial burst of merchant construction in most areas of the country which, despite leading to excess capacity, did not cost customers a dime. This was an especially pertinent topic at the time of restructuring, as there were various notable examples of major cost over-runs in plant construction, especially with nuclear facilities.

Now, with many parts of the country expressing concerns about the adequacy of generation supply, certain states are pursuing policies aimed at providing incentives to build new generation. In competitive markets, wholesale prices provide the incentives to build new infrastructure, with customers free from the obligation to fund those investments. Many traditionally regulated states have recently passed laws providing for prior review of plant—cost recovery guarantees not available to merchant generators—and construction work in progress (CWIP) in rate base.[18] For example:

- <u>**Florida:**</u> In June 2006, legislation that affects several aspects of the state's energy policy was enacted. Senate Bill (S.B.) 888 exempts nuclear power plants from the requirement of a competitive bid and provides for recovery of pre-construction costs and a cash return on CWIP during the construction period of a nuclear power plant. A similar bill, House Bill (H.B.) 549, was enacted on June 12, 2007. This legislation authorizes deferred accounting for the pre-construction costs of integrated gasification combined-cycle (IGCC) plants, and these costs are to accrue a carrying charge equal to the utility's AFUDC rate. All prudently incurred pre-construction costs are recoverable through the utility's capacity cost recovery clause, as is a current return on CWIP.

- <u>**North Carolina:**</u> Senate Bill (S.B.) 3, which was enacted on August 20, 2007, facilitates the NCUC's ability to allow a cash return on CWIP by removing statutory language that had permitted utilities to earn a cash return on CWIP only "to the extent [...] such inclusion is in the public interest and necessary to the financial stability of the utility in question." As an example, the NCUC recently approved the recovery of pre-construction development costs for the proposed Duke Energy Lee Nuclear Station, stating that "to the extent the Commission finds, in a future general rate case proceeding, the specific activities involved in, and the costs of pursuing such Development Work to be prudent and reasonable (whether or not the Lee Nuclear Station is constructed), Duke may

[18] CWIP in rate base, which provides cash before a plant operates, does not occur in competitive markets. For regulated utilities, there have been instances where commissions have allowed CWIP to be recovered when a regulated utility needs cash flow assistance or when Allowance for Funds Used During Construction (AFUDC) balances, which are "paper" earnings not "cash" earnings, grow large and become burdensome financially. Normally, however, CWIP in rate base is not allowed as the plant is not yet benefiting customers, but in order to induce utilities to build more states are formalizing CWIP allowances.

recover" the Development Work costs in rates.[19] These development costs are expected to total $125 million.

- __Nevada:__ In 2004, the PUC adopted revised integrated resource planning rules that permit the Commission to approve an incentive mechanism for generation facilities designated as "critical." Under the rules, the PUC has the option to designate a project as critical if it protects reliability, promotes supply diversity, or utilizes renewable resources. For such a project, the utility may be awarded a financial incentive including: (1) an enhanced ROE on the designated critical facility over the life of the facility; (2) a cash return on CWIP associated with the facility; or (3) the deferral of costs incurred to construct the facility.

- **__Wisconsin:__** Through an ROE adder, the PSC generally allows a current return on 50 percent of a utility's electric and gas CWIP, except for major generation projects where the PSC generally allows a current return on 100 percent of the CWIP associated with that project.[20]

The trend is clear: the US needs to build new generating capacity, greatly increase energy efficiency, or initiate a combination of both in order to meet demand for electricity and diversify the supply mix away from old technology. Cost-of-service regulation could accomplish this, but going down that path will necessitate iron-clad cost recovery assurances for increasingly expensive generation assets.[21] Regulated entities may be volunteering to build new generation, but not without cost recovery guarantees and payments before plants are in service. While the prior building cycle proved that recovery assurances need to be provided to investors, the amount of price risk faced by consumers does not seem to have sunk in. Customers may not yet be aware of the long-term commitments that are being made on their behalf by utilities and their regulators.[22]

B. Economic Efficiency Gains

Reliance on competitive markets is based on the principle that firms with the most efficient production and the most value for consumers should and will prevail. Efficient competition leads to production at the lowest achievable costs in the long-term, which is a socially desirable outcome that results in an efficient use of society's resources. Currently, with

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[19] Regulatory Research Associates, Inc., Focus Notes, March 30, 2007. A similar approval was granted by the Ohio Public Utilities Commission to American Electric Power (AEP) in 2006, which allowed for the recovery of $24 million in pre-construction costs related to an IGCC facility. *See:* Regulatory Research Associates, Inc., Focus Notes, April 27, 2007.

[20] Regulatory Research Associates, Inc., State Commission Overviews, various dates.

[21] From May 2005 to October 2006, Duke Energy's estimate of construction costs for two new coal-fired plants at its Cliffside site went from $2 billion to $3 billion. The North Carolina Utility Commission ultimately approved a single plant for $1.8 billion, an 80 percent increase from the initial estimate—and that number is still just an estimate. Similarly, Entergy's cost to re-power its Little Gypsy site was estimated in April, 2007, to cost $1 billion; by July, 2007 this figure had increased by over 50 percent to $1.55 billion.

[22] We are not saying that such guarantees and cash flow allowances are unjustified or unnecessary. To the contrary they may be required in regulated situations. The point is that this is a major difference between the regulated and competitive solutions.

transition to competition periods beginning to end, it is too early to determine the ultimate success or failure of electricity competition—but it is possible to see some encouraging trends.

With competition, generation operators' incentives changed dramatically, leading to changes in microeconomic behaviour. Though they may not be immediately evident in prices, benefits are clear in non-price advantages such as greater service variety and the presence of a functioning market for capacity (which promotes efficient investment decisions).

Research papers that focus on measures of efficiency other than price, such as generator efficiency or operating cost reductions, offer a more complete indication of the impacts of competition in the current environment. Research has found that:

- Operating costs of generating plants in states that chose to restructure have been reduced relative to costs of generating plants in states that decided against implementing competition.[23] Plant operators affected by competition reduced labor and non-fuel expenses by about 3%-5% relative to other IOUs and 6%-12% relative to cooperatives or government-owned generation.[24] Similarly, divested generating plants and those subject to incentive regulation mechanisms improved their fuel efficiencies compared to their peers without high-powered incentives.[25]

- One of the benefits introduced by competition in generation was to improve the performance of previously existing generating assets in the face of competition. Availability, non-fuel operating costs, and heat rates improved significantly. Availability of generating capacity has increased over time in both New England and New York. Equivalent availability factors increased significantly in PJM from 1994 to 1998 and have been roughly constant since then with some year-to-year variability.[26] Relatively small efficiency gains—such as a two percent improvement in heat rates—can provide hundreds of millions of dollars of annual fuel savings.

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[23] Fabrizaio, K., N. Rose and C. Wolfram, "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency," *The American Economic Review*, Vol. 97 No. 4, 2007.

[24] *Id.*

[25] Bushnell, J. and C. Wolfram, *Ownership Changes, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generating Plants*, University of California Center for the Study of Energy Markets, CSEM WP-140, March, 2004.

[26] Paul L. Joskow, "Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector," *Journal of Economic Perspectives*, 11(3): 119-138, 1997.

ISO New England, *2004 Annual Markets Report*, 2005, http://www.ksg.harvard.edu/hepg/Papers/ISONE_2004_annual_markets_report.pdf (Accessed 11/2/07).

New York ISO, *2004 State of the Markets Report*, prepared by David Patton, 2005, http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/2004_patton_final_report.pdf (Accessed 11/2/07).

PJM Interconnection, *State of the Market Report 2004*, 2005, http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/pjm-som-2004.pdf (Accessed 11/2/07).

Markets reward innovation—the search for and discovery, development, adoption, and commercialization of new products, services, organizational structures, processes, and procedures—that meets market demand. The role of competitors in the marketplace is to compete on the basis of price and value. While competing on the basis of price is obviously very important, successful competitors can also innovate and offer the customer something better than that offered by standard service. Some value-added services may be related to price, such as information services that improve a customer's ability to manage its energy usage. Value could also be provided in the form of green power, risk management (fixed prices for seasons or a year), bundling of services, or could take a form that is not currently anticipated.

C. Energy Efficiency and Renewables

Energy efficiency, distributed energy resources (DER) programs, and renewables (e.g., wind) all benefit from transparent markets and the competitive incentives that restructured markets provide. In a competitive situation (with an RTO or ISO), it is more likely that price signals for generation services (energy, capacity, and ancillary services) will be market based, and it is also more likely that service providers or retailers will be involved.

1. Market Transparency and Demand Response

Innovative RTO/ISO programs are providing incentives for a wide variety of needed generation and transmission-related resources. The ISO-RTO Council, made up of ISOs and RTOs serving two-thirds of the US market and half of the Canadian market, recently issued three reports documenting the success they have had in terms of managing demand response programs and encouraging renewable investment.[27] The reports note various ways in which RTOs can facilitate renewable development including clear, expeditious, and nondiscriminatory interconnection processes and market-based ancillary services.

Demand response programs that respond to real-time prices can also serve to moderate spot price spikes. Demand response programs work best in transparent markets, which eliminate the need to use an administered-type price, such as avoided cost pricing, which may give very misleading price signals. With a transparent market providing price signals, it becomes possible to fairly evaluate energy efficiency, demand response programs, and renewable resources. Furthermore, ISOs, by definition, have no stake in market outcomes. Because they own no generation, they are neutral with respect to the ownership and types of generating units that operate within their system. The same is not always true for utilities.

2. Availability of Information and Price Signals

It is imperative for potential investors in renewable sources of energy to have access to detailed pricing information so that they can judge the feasibility of their projects. In regard to this, and in support of competition, the ISO/RTO Council reported: "ISO and RTO wholesale markets provide price transparency to inform all market participants, including renewable

[27] For more information, please *see*: ISO/RTO Council, Increasing Renewable Resources, October 16, 2007; ISO/RTO Council, Progress of Organized Wholesale Electricity Markets in North America, October 16, 2007; Markets Committee of the ISO/RTO Council, Harnessing the Power of Demand, October 16, 2007.

generation owners, about the price and the value of their power."[28] In addition, the report notes: "[i]n wholesale electricity markets, developers have access to both historical data and forward price curves to estimate the future value of their generation."[29] This lies in stark contrast to projects not in ISO/RTO regions, where it is likely that the developer will negotiate price bilaterally with the utility, and will not have access to public price information.

The availability of time-based market prices and demand response capability can change the energy cost structure faced by certain utility customers during peak periods, resulting in increased consumer price responsiveness (i.e., elasticity). Thus, customers participating in demand response programs benefit from transparent market prices. Through the market process of numerous buyers and sellers making individual decisions, competitive markets allow consumer demands to be sorted out and aggregated by producers at the lowest possible cost. The price information provided by the market gives buyers and sellers the information they need to make their individual production and purchasing decisions. The Markets Committee of the ISO/RTO Council issued a positive review of ISO/RTO management of the demand response programs in the US and Canada, stating that:

> The markets these ISOs and RTOs administer, which represent approximately two-thirds of electricity demand across the United States and just over 40 percent in Canada, are playing an important and growing role in enabling demand response to reach its full potential. They provide visible price signals that will help consumers make rational decisions about expenditures on electricity in the same way they use market prices for deciding how to purchase other goods and services.[30]

Given the price signals provided by a transparent real-time spot market, demand response programs can be more effective in restructured jurisdictions. Efficiency investments are also spurred when customers see true market prices and can make decisions to use energy more efficiently based on those prices.

States with competitive markets can avoid relying heavily on administratively set credits that may not always adjust readily to reflect changes in costs. Administratively set credits have an important defect: they are *static* in nature, while wholesale power markets are inherently dynamic over time. In dynamic power markets, administratively set credits rapidly become stale and can trigger incorrect and outdated responses. One lesson from the implementation of PURPA in the 1980s is that, in the absence of market prices, setting avoided cost rates is a very difficult task to complete correctly. When wholesale market price information is readily available, these challenges are reduced.

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[28] ISO/RTO Council, *Increasing Renewable Resources*, October 16, 2007, p. 11.

[29] *Id.*

[30] Markets Committee of the ISO/RTO Council, *Harnessing the Power of Demand*, October 16, 2007, p. 1.

3. Renewable Generation Growth

The records on prices that are maintained by ISOs and RTOs can serve as valuable information to companies deciding whether or not to invest in renewable generation assets. But what has actually happened in recent times, in terms of the *growth* in generation from renewable resources in restructured vs. traditionally regulated states?

Table 2: Growth of Renewable Generation in Restructured and Traditional States 2000-2005

	Growth Rate
Restructured States	11.3%
Traditional States	0.6%

Source: EIA.

Total renewable generation increased in both markets during the period of time between 2000 and 2005. However, renewable net generation in restructured states increased by approximately 11.3 percent, while there has been an increase of less than one percent in traditionally regulated states. This is not to say that restructuring was completely responsible for the relatively larger increase in renewable net generation in restructured states. To prove this, a multitude of other variables would have to be considered, including overall trends in electricity demand, and separate state policies regarding renewables. These statistics are important, however, given the expectation that independent power providers compete based on short term marginal cost, and that renewables would therefore not be viable competitors. In addition, utilities in restructured markets are not mandated to purchase power from PURPA qualifying facilities.[31] At the very least, the growth in renewable net generation in restructured states shows that the transparent market prices, customer choice, and renewable standards that are available in restructured markets help to provide a favorable environment for renewables.

There have been many recent examples of renewables gaining a stronger foothold in restructured markets. For instance, in Maine, a proposed mountain ridge wind farm has already sold its first 10 years of renewable energy.[32] This project is expected to power 44,000 households and reduce daily air emissions in the region by 430 tons a day. Harley Lee, President of Endless Energy in Yarmouth, issued a statement that highlighted Constellation's role as a power marketer, noting that "[o]ur region has lagged behind other parts of the country in the use of

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[31] As part of the Energy Policy Act of 2005, Congress substantially narrowed the applicability and scope of QF must-buy requirements. Thus, utilities in much of the US will be relieved from the Section 210 requirements applicable to new QF facilities, with a showing that a new QF has nondiscriminatory access to competitive wholesale markets that meet the applicable standard. For utilities that cannot show that the new QF has access to competitive wholesale markets that meet the Section 1253 standard, the PURPA "must buy" requirements will continue.

[32] Donna M. Perry, "Redington Wind Farm has Deal to Sell Power," *Sun Journal*, April 6, 2006.

wind energy. A major reason has been the lack of a power marketer willing to sign long-term contracts."[33]

Other positive examples of renewable energy in restructured states include an agreement between Constellation and Horizon Wind Energy for an 18-year renewable energy power purchase agreement,[34] a contract between Epuron LLC (Conergy) and Exelon Generation for a 20-year power purchase agreement for the energy produced at a proposed 3 megawatt (MW) solar energy power station in Morrisville, Pennsylvania,[35] and the success of PECO Wind in Pennsylvania.

VI. CONCLUSION

State policy makers face a difficult situation. Restructuring transition periods have ended or are ending as prices are rising across the country. Prices have generally been rising over the past several years, regardless of market structure, primarily because of rising input fuel prices. At the same time, investment needs are growing and environmentally beneficial renewables are being mandated by legislation. Carbon emissions, which are not limited at all now, could be limited moving forward, which will further increase prices. Upward pressure on natural gas and oil prices show no signs of relenting. Even generation equipment costs are rising as the metals needed for their manufacture increase in price, and as demand drives up engineering and construction labor costs. Price increases are unpopular, and in the search for a villain, it is easy to blame competition. The facts, however, do not support the hypothesis that competition is the cause of price increases. The rise in oil and gas prices, equipment costs, impending carbon control costs, and the mandate to replace older and dirtier generation with alternative units are the primary factors behind these price increases. Both competitive and traditionally regulated states are seeing the impact of input price increases.

It is true that restructuring was misunderstood and, in many cases, unrealistic expectations may have been set. The implication that restructuring would always lead to lower prices was not accompanied by the obvious "all else being equal" or "over the long term" provisions. Abstracting from oil and gas prices, renewable mandates, equipment cost increases, and carbon reduction costs, it is likely that prices in restructured states would have declined as transition periods ended. But that did not happen, and industry structure cannot compensate for sharp increases in input prices.

In theory and in practice, restructured markets are superior in providing production efficiency incentives, in encouraging efficient demand side activity, and in encouraging investment in alternative forms of generation. We also know that in competitive markets customers bear much less risk. These factors all point to a policy that favors competition over

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[33] *Id.*

[34] Constellation Energy, *Constellation Energy to Purchase Wind Power From Horizon Wind Energy's Twin Groves II Project*, July 25, 2007, http://ir.constellation.com/phoenix.zhtml?c=112182&p=irol-newsArticle&ID=1030961&highlight= (Accessed 11/2/07).

[35] *Epuron, Exelon Join Forces on 3 MW Pennsylvania Solar Facility*, RenewableEnergyAccess.com, September 4, 2007, http://www.renewableenergyaccess.com/rea/news/story?id=49828 (Accessed 11/2/07).

cost-of-service regulation. Electricity generation is a capital intensive industry with long lead times, and the benefits of competition cannot be expected to be seen overnight.

We also know that cost-of-service regulation performed poorly during the last major generation building cycle. However, these lessons, while very relevant, may not stand out to current policy makers who were not involved in the industry in the 1970s and 1980s. Competition, with all its imperfections and transitional problems, is too often compared to an idealized version of regulation that may exist in theory but not in practice.

Before rushing to judgment on restructuring and undoing competitive markets, policy makers should consider the following facts:

- Competition and cost-of-service regulation are fundamentally different and competition will shift risk from customers to investors.

- The risks borne by customers and the outcomes they were exposed to under the last significant non-gas capacity expansion are what led states to restructure. In many states, cost-of-service regulation failed in the 1980s.

- States continuing in the cost-of-service regulated model are providing iron-clad cost recovery guarantees for new generation investment and prudence pre-approval.

- The market prices seen in competitive markets will encourage efficient penetration of energy efficiency (conservation) and facilitate demand response, lowering investment needs, and providing environmental benefits.

- Competitive markets have led the way in renewable energy development.

- Recent price increases are largely driven by input price increases, and have occurred in both competitive and traditionally regulated states.

While restructuring may not have been perfectly implemented and there will always be room for improvement, the facts above suggest that regulatory efforts would be better directed at refining and improving the competition model rather than returning to the cost-of-service regulated model.

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Plant:
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			Plant Capacity				Cost Calculation						Case: Unit Always Running (Les	
Date	He	Hourly LMP ($/MWh)	Min Capacity (MW)	Max Capacity (MW)	Capacity Level at Most Efficient Operating Point (MW)	Capacity Level where P = MC (MW)	Operating Level (MW)	Average Heat Rate @ Operating Level	Adjusted Fuel ($/MMBTU)	Variable O&M ($/MWh)	Start-up Costs ($)	Variable Energy Cost ($/MWh)	Gross Revenues ($)	Energy Costs ($)
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s Maintenance and Retirement)		Technical Constraints		Min Up/Down Time					Dispatch and Revenues				
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$ (1,218.52)	$												
$ (3,438.01)	$												
$ (4,405.58)	$												
$ (4,331.37)	$												
$ (3,579.58)	$												
$ (1,238.46)	$												
$ 1,766.58	$												
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$ 9,755.68	$												
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$ 40,793.27	$												
$ 39,926.90	$												
$ 26,814.70	$												
$ 19,122.51	$												
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$ 9,657.14	$												
$ (467.09)	$												

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