R-00973953; R-00973953C0001 — C0017

EPMI et al

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E.H.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DIRECT TESTIMONY OF

STEVEN J. KEAN

ON BEHALF OF

ENRON POWER MARKETING, INC.

DOCKET NO. R-00973953

RE: PECO RESTRUCTURING PLAN

JUNE 20, 1997

I. STATEMENT OF QUALIFICATIONS

Q. WHAT IS YOUR NAME AND ADDRESS?

A. My name is Steven J. Kean and my business address is 1400 Smith Street, Houston, Texas, 77002.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am a Senior Vice-President of Governmental Affairs for Enron Corp. ("Enron").

Q. PLEASE PROVIDE A DESCRIPTION OF ENRON.

A. Enron is one of the world's largest integrated natural gas and electricity companies with approximately $15 billion in assets; it operates one of the largest natural gas transmission systems in the world; is the largest purchaser and marketer of natural gas in North America; is a leading participant in liberalized energy markets in the United Kingdom and the Nordic Countries; markets natural gas liquids worldwide; manages the largest portfolio of fixed-price natural gas risk management contracts in the world; is one of the leading entities arranging new capital to the energy industry; owns a majority interest in Enron Oil & Gas Company, one of the largest independent (non-integrated) exploration and production companies in the United States; owns and manages operating power plants and natural gas pipelines around the world; is one of the largest independent developers and producers of electricity in the world; and is a major supplier of solar and wind renewable energy resources.

For the purposes of this testimony, I am representing Enron Power Marketing, Inc. ("EPMI"), which is the largest marketer of electricity in North America. EPMI is also a leading participant in the emerging retail electricity markets, participating in the New Hampshire retail wheeling pilot program and the direct access experiment operated by Illinois Power.

Q. WHAT ARE YOUR RESPONSIBILITIES WITH ENRON?

A. I am responsible for the public policy, legislative, and regulatory activities of Enron, and its subsidiaries, within North America. My primary responsibility relates to supporting customer choice for electricity and natural gas at both the state and the federal level.

Q. WHAT PRIOR EXPERIENCE DO YOU HAVE?

A. Before working at Enron, I worked as Counsel for both Utilicorp and El Paso Natural Gas. At Enron, I have previously worked as Assistant General Counsel for Florida Gas Transmission, and as Vice President for Regulatory Affairs for Enron Power Marketing, Inc.

In all of these roles, I have worked within industries and companies undergoing regulatory and legal restructuring.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I graduated from Iowa State University in 1982, and received my Juris Doctor from the University of Iowa in 1985.

Q. HAS ENRON PARTICIPATED IN THE RESTRUCTURING DEBATE IN PENNSYLVANIA?

A. Yes. Enron participated in negotiating and encouraging the enactment of the Electricity Generation Customer Choice and Competition Act (the "Competition Act"), and continues to be involved with the Commission's proceedings and working groups relating to implementing direct access for electricity.

II. <u>INTRODUCTION AND SUMMARY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In my testimony I will describe a vision for the future of retail electric services in a competitive environment and the policy choices necessary to achieve that vision.

Q. DESCRIBE YOUR VISION FOR A COMPETITIVE ELECTRIC SERVICES MARKET.

A. My vision centers around one primary objective: meaningful choices for <u>all</u> consumers of electricity -- from homeowners to the largest industrial users. Ensuring that all consumers have meaningful choices requires policy choices which provide numerous suppliers, not just the incumbent utility, with access to consumers. In an open and competitive market for retail electric services, consumers will have the ability:

- to choose a new supplier of electricity,
- to receive a single bill for those services from the supplier of their choice,
- to have access to various service alternatives from their electric suppliers, including new metering which will enable suppliers to provide real time pricing information,

- to provide information to aid the consumer in conservation decisions,
- to reduce the administrative costs of serving customers,
- to identify opportunities for energy efficiency investments, and
- more easily to aggregate customer load for scheduling purposes.

In this environment consumers benefit from lower costs, better service and improved service offerings.

Consumers will see lower costs because the availability of alternative suppliers will create price competition among suppliers, as it does in every open market. Suppliers will look for ways to cut costs, to find less expensive supplies and increase the efficiency with which they make delivery of those supplies.

Consumers will see better service and improved service offerings for the same reason -- competing suppliers will distinguish themselves by the reliability of their service, the quality of information they provide, the accuracy of their bills, and the precision with which they fill a specific customer's needs. Services will be designed for specific residential, commercial and industrial customers. Opportunities to lower customers <u>bills</u>, not just their rates, will be identified. Suppliers will distinguish themselves on their responsiveness to customer inquiries and concerns.

Q. WHAT POLICY CHOICES ARE REQUIRED TO MAKE THIS VISION REALITY?

A. The Commission must:

1. Provide equal, nondiscriminatory access to essential facilities to competing suppliers.

2. Permit competition in all services which can be competitively provided.

3. Prevent utilities from using their control of essential facilities to advantage their competitive business.

Equal access to essential facilities means open access transmission and distribution service under unbundled tariffs which all providers, including the utility or its affiliate, must use. Incumbent suppliers (and their affiliates) must be required to use the same tariff options that are available to competing suppliers. Otherwise utilities will have an incentive to structure tariffs which are inferior to the use the utility or its affiliate makes of its own system. In the natural gas business the Federal Energy Regulatory Commission required open access tariffs and required that pipelines conduct sales, if at all, only through a separate affiliate which

1. was separated from the pipeline by enforceable (and enforced) standards of conduct,
2. had to use the same open access transmission tariffs as its competitors, and
3. could only serve those customers who affirmatively chose its service -- i.e. they had to compete for customers' favor, they didn't simply inherit customers from the pipeline.

This approach, which I recommend to the Commission in this proceeding, had several important benefits. First, it forces the affiliate to offer customers a better deal. Second, it forces the utility to propose tariffs that work because the utility's own affiliate will have to use the same tariff. Third, it keeps the utility from using overt and covert attempts to discourage customers from switching. If the utility or its affiliate is allowed to serve everyone who doesn't choose, it will have a powerful incentive to discourage switching by erecting barriers to switching or suggesting that safety, reliability or service quality will be threatened if the customer switches.

Permitting competition in all competitive services means unbundling all services which the utility currently embeds in its service, and requiring that those services be separately priced and offered. These services include not just transmission and distribution but also metering, billing and customer information services. It also means allowing competing suppliers to offer not just the commodity but also these other competitive services. Metering, billing and customer information services are not "natural monopolies". They can be competitively provided and are competitively provided in other industries. Competition can lower these costs, improve them and open the door to other value added services to consumers.

Preventing utilities from using their transmission and distribution monopolies to advantage their sales and other competing business lines means putting in place standards of conduct governing the relationship between the generation and distribution businesses.

It also means opening the interface with the customer. The competitive provider must be allowed to procure the transmission and distribution service, pay the utility for it, and provide the customer with a single bill. In competitive businesses, suppliers are allowed to arrange for delivery with a delivery services company and provide a single bill to their customer. Imagine the impediments to competition and good customer service if, for example, a supplier of goods were forced to have its customers separately arrange and/or pay for delivery or, worse yet, forced to receive payment or send the bill through a competitor.

III. PRESENTATION OF WITNESSES

Q. PLEASE DESCRIBE THE WITNESSES THAT WILL BE PRESENTING DIRECT TESTIMONY FOR ENRON IN THIS PROCEEDING.

A. Do. John Mayo will testify on the issue of the benefits that will flow from a robust and broad competitive electricity services industry. Mr. Lynn Coles from R.W. Beck Consulting, along with Dr. Richard Tabors from Tabors Caramanis & Associates, will discuss the necessary rules, terms, and rates for Enron's usage of PECO Energy's transmission and distribution system. Mr. Paul Reising, a principal with R.W. Beck, will present Enron's alternative proposal for a Distribution Services tariff, and discuss the technical issues regarding the unbundling and rate design of PECO's wire and non-wire services. Mr. Malcolm Jacobson, from Enron, will describe how and why the Commission should require PECO Energy to unbundle additional competitive services beyond simply the commodity, such as metering and billing. Mr. Raymond Bowen, who heads Enron's residential marketing efforts, will discuss necessary consumer protections and rules so that all consumers including small users can benefit from this transition. Finally, Mr. Michael Dirmeier, from Georgetown Consulting Group, will provide an analysis and recommendations relating to the appropriate standards of conduct for PECO Energy.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. Thank you.

Exhibit 1, SJK-1

INGAA

Report No. 96-2

August, 1996

Rate and Policy Analysis Department

Background Report

COMPARISON OF GAS AND ELECTRIC INDUSTRY RESTRUCTURING COSTS

Summary

The natural gas industry has incurred $13.2 billion in restructuring costs as a result of regulatory changes that transformed interstate gas pipelines from merchants to transporters. INGAA's data indicate that, of the gas industry restructuring costs filed to date, pipelines have absorbed 28 percent, or $3.7 billion. Now federal and state regulators are debating treatment of stranded costs that may result from the restructuring of the electric utility sector.

There are several lessons from the gas industry experience that may be relevant to electric industry policy makers. First, interstate pipelines had to adopt open access and provide their customers with choices before their stranded cost liabilities were settled. Second, pipelines had powerful incentives to hold restructuring cost levels down. Pipelines were not permitted to recover their restructuring costs fully because of policies adopted by the Federal Energy Regulatory Commission, and because of competitive pressures introduced with open access. As a result, stranded costs in the gas industry turned out to be significantly less than expected. While the transition was laborious for the gas industry, regulatory and market changes contributed to savings for gas consumers even as these same changes created restructuring costs.

INTRODUCTION

The natural gas industry incurred significant costs during the 12-year development of open access and unbundled transportation services. The electric industry is expected to incur stranded costs as it restructures its business to provide open access and possibly retail wheeling. As the debate on the scope and pace of electric restructuring proceeds, parties have attempted to draw analogies between the gas and electric industry experience to advance or criticize proposals for regulatory treatment of stranded electric costs.

The purpose of this paper is to compare and contrast gas and electric restructuring costs in order to share some lessons from the gas industry experience.[1]

DEFINITIONS

To simplify this discussion, all gas and electric industry costs that were or could be incurred as a result of federal or state open access requirements will be referred to as "restructuring costs."

Natural gas industry restructuring costs have been at various times referred to as take-or-pay costs, transition costs, Order No. 636 costs, gas supply realignment costs and stranded costs. In fact, as discussed below, each of these names describes costs incurred by the natural gas industry as a result of regulatory changes that transformed pipelines from gas merchants to gas transporters.

For the electric industry, restructuring costs generally refer to costs that the Federal Energy Regulatory Commission (FERC or Commission) or a state regulatory body approves as legitimate, prudent, and verifiable costs of providing service that have been recovered to date through bundled rates, but whose future recovery will be affected by the advent of competition in the generation sector and by retail access. FERC has issued Order No. 888, which deals with, among other issues, the rules regarding recovery of electric utility stranded costs under its jurisdiction. There are no definitive state rules yet on stranded cost recovery.

IDENTIFICATION OF COSTS

We have classified gas and electric restructuring costs into two categories: stranded assets and stranded liabilities (see Table 1). An asset is a fixed cost of production that

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restructuring costs characterized as the most likely scenario for 114 investor-owned utilities over a 10-year period.[5] This estimate reflects the fixed costs of generation that will not be recovered by an anticipated competitive market price for electricity.

Most utilities own generation assets and purchase power under term contracts to meet total requirements. Long-term purchased power agreements that have rates above market prices will potentially be stranded. INGAA has estimated that stranded contract liabilities, including payments to PURPA-qualifying facilities, could total $52.5 billion.[6] Assuming Moody's $135 billion is a reasonable estimate of total power generation that will become uneconomic due to restructuring, then the stranded asset (fixed costs of a utility's own generating capacity) portion of the total could amount to $82.5 billion.

REGULATORY TREATMENT OF GAS RESTRUCTURING COSTS

The Take-or-Pay Era: 1988-1993. Costs associated with industry restructuring became a problem for interstate pipelines in the early 1980s. The "take-or-pay" liabilities that pipelines incurred represented contractual obligations for minimum quantities of gas from producers at prices that could not be recovered in the increasingly competitive gas supply market. FERC did not abrogate pipeline-producer contracts, so pipelines were forced to buy their way out of the contracts. Pipelines settled some of their take-or-pay obligations with producers through cash payments and contract reformation. But as FERC began the transition to open access in 1984, pipeline sales declined and take-or-pay liabilities grew.

In response to a court remand on its failure to address the growing take-or-pay problem, in 1987 FERC adopted two cost-recovery mechanisms in Order No. 500. A pipeline could recover all prudently-incurred settlement costs in its sales commodity charge as it had in the past, although such recovery was increasingly difficult as pipeline sales declined. Alternatively, if a pipeline agreed to absorb between 25 percent and 50 percent of its take-or-pay costs, i.e., write-down such costs, it could recover an equal share through a fixed charge and recover the remaining amount (up to 50 percent) through a

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5 Moody's Investors Service, *Stranded Costs Will Threaten Credit Quality of U.S. Electrics*, August, 1995.

6 INGAA's $52.5 billion estimate is based on information developed by Resource Data International, in Public Utilities Fortnightly, *Power Purchase Contracts Could Strand Billions* (November 15, 1994), pages 14-15. RDI suggested that potential stranded liabilities from above-market purchased power contracts could be over $15.0 billion annually. To make this estimate comparable to the Moody's estimate for total stranded costs, INGAA adjusted the RDI estimate downward to the investor-owned utility share of approximately 55 percent, or $8.2 billion annually, and applied Moody's assumptions of a 10-year transition to full competition and a 9 percent discount rate.

Between 1993 and 1996, pipelines filed $3.0 billion of what were termed "transition costs" under Order No. 636 (see Table 2). By this time, in an almost fully unbundled market, there was tremendous pressure for pipelines to ensure that their individual rates were competitive with other pipelines in the same supply or market areas. As a consequence, pipelines used many more mechanisms to keep transportation rates that included restructuring costs competitive, such as assignment of contracts to customers and speedier resolution of settlements and absorption amounts.

Table 2
Natural Gas Industry Restructuring Costs
($ billions)

	1988-93	1993-96
• Gas Supply Realignment		
– Absorbed by Pipeline	$ 3.7	NA
– Absorbed by Customers	$ 6.5	$ 1.8
Subtotal-Gas Supply Contracts	$ 10.2	$ 1.8
• Account 191	-	$ 0.5
Total Gas Supply Costs	$ 10.2	$ 2.3
• Stranded	-	$ 0.7
• Total	$ 10.2	$ 3.0

Total Natural Gas Restructuring Costs 1988-96 = $13.2 billion

WHO PAID FOR GAS INDUSTRY RESTRUCTURING?

Different segments of the natural gas industry absorbed costs associated with its open access regulation.

Pipeline stockholders have absorbed at least 28 percent of actual restructuring costs to date ($3.7 billion out of $13.2 billion), primarily as a result of the equitable-sharing requirements in the late 1980s. Stockholders also paid in terms of loss of investment value. During the 1980s, pipeline financial indicators such as stock prices and bond ratings reflected the losses sustained by the pipelines for take-or-pay costs and the regulatory uncertainty surrounding the issue.

Pipelines paid producers $12.0 billion to reform or buy-out gas supply contracts. The gas supplies were resold by producers at prices below the original contract amount. But while producers received take-or-pay and settlement payments and the (now lower) market value of their gas, they did not always receive the full contract value. Therefore, gas producers (the holders of the contract liabilities) were one of the parties that paid for restructuring.

Order 888 or at the retail level.[12] While the policies for treatment of stranded gas and electric costs at the federal level are comparable, there are some important differences that will influence the outcome of electric stranded cost recovery.

The extent of Federal jurisdiction is quite different. FERC was in a position to set the recovery policy for virtually all interstate pipeline restructuring costs that have been filed to date, whereas individual states will set recovery policies for the bulk of electric restructuring costs.

The industry structures are also different. Payments for gas restructuring costs went primarily to third parties, namely producers that were not affiliated with the pipelines. However, stranded costs for generation assets, the major electric category, are owned by the same companies that seek to recover the costs. Therefore, the dynamics of arm's-length negotiations that gave each party the incentive to seek the best possible deal for GSR costs may not be present for stranded electric assets.

CONCLUSION: LESSONS LEARNED

There are several lessons from the natural gas experience that are relevant to the treatment of restructuring costs in the electric sector. First, pipelines had to adopt open access and provide their customers with choices before their stranded cost liabilities were settled and before mechanisms were established for their recovery. In other words, the Commission took an "access first, stranded cost recovery later" approach.

Second, pipelines were not permitted to recover their restructuring costs fully because of Commission policy, competitive pressures or both. As a result, pipelines had powerful incentives to hold restructuring cost levels down and gas industry stranded costs turned out to be significantly less than originally expected. Nevertheless, the failure to address the stranded cost problem in Order No. 436 led the Court to remand the Order. Meanwhile, forcing shareholders to absorb prudently-incurred costs contributed to a period of financial and market instability in the gas industry.

If natural gas industry restructuring is any example, a sound approach for electric industry policy makers is to establish a policy of customer choice first. Issues related to stranded cost recovery can then be dealt with by federal and state regulators, as appropriate. Only by opening the market can the true value of stranded assets and contracts be determined, while customers receive the benefits of offsetting efficiency gains and lower consumer prices.

12 Some state commissions have allowed accelerated write-offs of generating assets by electric utilities in order to get ready for competition.

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