Commonwealth of Virginia

State Corporation Commission

Report to the Commission on Electric Utility Restructuring of the Virginia General Assembly

Stranded Cost Report

Volume II

Pursuant to the Legislative Transition Task Force's Resolution
Adopted January 27, 2003

July 1, 2003

Stranded Cost Report

Attachments included in Volume II

7 Responses to Questions Posed in the Commission's January 27, 2003 Order
- Dominion Virginia Power
- ODEC Member Cooperatives
- American Electric Power
- Allegheny Power
- Virginia Independent Power Producers
- Division of Consumer Counsel Office of Attorney General
- Virginia Committee for Fair Utility Rates and Old Dominion Committee for Fair Utility Rates
- Washington Gas Energy Services
- National Energy Marketers Association

8 Staff's E-mail Dated April 02, 2003 and Work Group Participant Responses
- April 02, 2003 E-mail Requesting Comments on Definitions

Comments Received:
- Dominion Virginia Power
- ODEC Member Cooperatives
- American Electric Power
- Allegheny Power
- Virginia Independent Power Producers
- Division of Consumer Counsel Office of Attorney General
- Virginia Committee for Fair Utility Rates and Old Dominion Committee for Fair Utility Rates
- Constellation NewEnergy, Inc.

9 Staff's E-mail Dated April 10, 2003 and Work Group Participant Responses
- April 10, 2003 E-mail Requesting Comments on Dominion Virginia Power's Methodology and Staff's Asset Valuation Methodology for Calculating Stranded Costs

Comments Received:
- Dominion Virginia Power
- ODEC Member Cooperatives
- American Electric Power
- Allegheny Power
- Virginia Independent Power Producers
- Division of Consumer Counsel Office of Attorney General
- Virginia Citizens Consumer Council
- Virginia Committee for Fair Utility Rates and Old Dominion Committee for Fair Utility Rates
- TXI-Chaparral (Virginia) Inc.
- Washington Gas Energy Services, Inc.

- Constellation NewEnergy, Inc.
- National Energy Marketers Association
- New Era Energy

10 Staff's E-mail Dated April 30, 2003 and Work Group Participant Responses

- April 30, 2003 E-mail Requesting Comments on the Methodology Presented by VCFUR/ODCFUR, Staff's Accounting Approach and the Clarification made to Dominion Virginia's Methodology

Comments Received:

- Dominion Virginia Power
- ODEC Member Cooperatives
- American Electric Power
- Allegheny Power
- Virginia Independent Power Producers
- Division of Consumer Counsel Office of Attorney General
- Virginia Citizens Consumer Council
- Virginia Committee for Fair Utility Rates and Old Dominion Committee for Fair Utility Rates
- TXI-Chaparral (Virginia) Inc.
- VML/VACo APCo Steering Committee
- Constellation NewEnergy, Inc.
- Strategic Energy LLC
- Pepco Energy Services
- Washington Gas Energy Services, Inc.
- National Energy Marketers Association

Attachment 7

RESPONSES TO QUESTIONS POSED IN THE COMMISSION'S JANUARY 27, 2003 ORDER

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

COMMONWEALTH OF VIRGINIA, *ex rel.*	)	
	)	
STATE CORPORATION COMMISSION	)	
	)	CASE NO. PUE-2003-00062
In the Matter of Developing Consensus	)	
Recommendations on Stranded Costs	)	

RESPONSE OF VIRGINIA ELECTRIC AND POWER COMPANY

In response to the Commission's Order Establishing Proceeding dated March 3, 2003, Virginia Electric and Power Company ("Dominion Virginia Power" or the "Company") states as follows:

PRELIMINARY

The provisions of the Virginia Electric Utility Restructuring Act ("the Act") are the result of years of legislative study. No provisions of the Act generated more discussion and debate, nor received more legislative attention, than those related to stranded costs. It is therefore very helpful to review this history as we embark upon a further undertaking with regard to stranded costs. Attached to this response is an appendix (Appendix A) with an attachment, which contains the legislative background of the stranded costs provisions of the Act.

A review of the legislative background contained in Appendix A shows why the General Assembly rejected up-front calculations and asset-valuation as a means of quantifying stranded costs. The review also reveals that the legislature intentionally decided, as reflected in the Act, on a workable and flexible method of stranded costs recovery over a reasonable period of time tailored to each utility.

RESPONSES

Response to Question 1. In generic terms, stranded costs are those generation costs incurred or commitments made by utilities under cost-based regulation that the utility may not reasonably expect to recover in a competitive market.

Because of the difficulty and controversy inherent in measuring stranded costs, the General Assembly adopted a "lost revenue" or capped rate/wires charge approach to recovery of such costs, as described in Appendix A. To the extent that a utility's unbundled generation rates exceed projected market prices, as determined by the Commission, the Act permits, for a limited period of time, the utility to impose a wires charge for customers who purchase electricity supply service from a competitive service provider ("CSP"). During that same time period, customers continuing to receive electricity supply service from the utility pay capped rates. The electric energy that would have been provided to customers who buy from a CSP ("displaced energy") is assumed sold at the projected market price. These sales, combined with the wires charges imposed on the CSP customers, prevent the utility from experiencing a loss in revenues due to a customer's decision to switch to a CSP. Issues such as valuation of generation plants and NUG contracts are thus avoided because they are not related to the lost revenue or the capped rate/wires charge approach adopted by the Act.

The Commission has implemented the stranded cost provisions of the Act as required by § 56-583. The Act recognizes that "the wires charges serve as a 'proxy' . . . of stranded costs," *Application of Northern Virginia Electric Cooperative for review of tariffs and terms and conditions of service*, Case No. PUE-2002-00086, Final Order, 2002 Va. PUC LEXIS 293, *5 n.3 (June 18, 2002), because the wires charges represent the difference between the utility's generation cost under cost-based regulation and the amount expected to be recovered for sales of displaced energy in a competitive wholesale generation market. This methodology produces a net stranded cost value by comparing the composite unbundled generation rate to the projected market price. The composite unbundled generation rate includes fossil, hydro, and nuclear assets, as well as purchases from NUGs. Use of the composite unbundled generation rate thus yields the same result as if the Commission independently compared the cost component of each resource to the projected market price, and then netted the resultant positive and negative wires charges when computing the weighted average overall wires charge. When a customer switches, this methodology assumes that the Company can recover the remaining portion of its unbundled, capped generation rate not represented by wires charges from "displaced 'power' [that] is assumed sold . . . in the wholesale power market." *In the matter of considering requirements relating to wires charges pursuant to the Virginia Electric Utility Restructuring Act*, Case No. PUE-2001-00306, Final Order (Oct. 11, 2002) ("2002 Wires Charges Final Order").[1] Thus, the wires charge revenues collected represent an annual estimate of the stranded costs applicable to switching customers that are not reasonably expected to be recovered from the wholesale power market.

On the other hand, if a customer does not switch, the Act entitles the Company to continue to recover its cost of serving that customer through its capped generation rates. Such capped rates have been fixed at levels found appropriate by the Commission to enable each incumbent utility to recover its cost of service, based on the last applicable rate case held for that company (plus fuel costs), under the terms of § 56-582. For such non-switching customers, the projected market price fixed annually by the Commission in the wires charge proceeding is

[1] The docket for this case remains open. On October 25, 2002, AEP-VA filed a Petition for Reconsideration, which was granted in part in the Order on Reconsideration, dated Nov. 1, 2002. The Order on Reconsideration does not relate to this quotation.

irrelevant. Projected market prices and wires charges only become important when a customer switches to a CSP.[2] Until then, the utility has an obligation to continue to serve that customer with its existing plant or market purchases, and an opportunity under the Act to recover the cost of such service.

Response to Question 2. As noted, the wires charge is an estimate developed by subtracting the projected market price of generation from a utility's unbundled generation rate. Under the Act, such projected market prices are determined by the Commission on an annual basis. For example, in Case No. PUE-2001-00306, the Commission approved projected market prices for 2002. *See In the matter of considering requirements relating to wires charges pursuant to the Virginia Electric Utility Restructuring Act*, Case No. PUE-2001-00306, Final Order, 2001 Va. PUC LEXIS 304 (Nov. 19, 2001) ("2001 Wires Charges Final Order").

The 2002 approved market prices of generation, which determine the wires charges by customer classes, are only estimates. Thus, any expected recovery of stranded costs provided by wires charges are estimates. After the end of each calendar year, however, Dominion Virginia Power can use the Commission-approved methodology to determine: (1) the actual market prices experienced during that year, (2) the actual wires charges that would have been collected, and (3) the actual wires charge revenue – i.e., stranded cost – that would have been recovered from customers that purchased electricity supply service from CSPs during the year.

The difference between the annual wires charge revenues collected from switching customers (based on the projected market prices of generation) and the wires charge revenues that would have been collected if the actual market prices were known represents the annual

[2] "Capped rates for electric generation services, only, shall also be established for the purpose of effecting customer choice for those retail customers authorized [to switch]." Code § 56-582(A)(2). "To provide the opportunity for competition . . ., the Commission shall calculate wires charges . . . ." Code § 56-583(A).

amount of over- and under-recovery. "Just and reasonable net stranded cost" is the total of the annual over- or under-recovery amounts of stranded cost for the 2001-2007 transition period. The final result (whether the utility has benefited or suffered under this methodology) cannot be known until after the end of the rate cap period in mid-2007. In the meantime, the rates determined by the Commission (including wires charges) "are reasonable and just to the utility and the public . . . ." *City of Norfolk v. The Chesapeake and Potomac Telephone Co. of Virginia*, 192 Va. 292, 304, 64 S.E.2d 772, 779 (1951).

Response to Question 3. The methodology for calculating "just and reasonable net stranded costs" requires a utility to determine whether there is over- or under-recovery of stranded costs collected through the wires charges from switching customers. As noted in the response to Question 2, the Company can compare the revenue actually collected from customers via the wires charges based on projected market prices to the revenue that would have resulted had wires charges been based on the actual market prices experienced during that year. If the revenue collected through the wires charges was greater than the revenue that would have resulted had the actual market price been correctly predicted, the wires charges were set too high, resulting in an over-recovery. If the contrary is the case, then there is under-recovery. An illustration follows:

At Beginning of Year

– Capped Generation Rate	$0.05 per kWh
– Projected Market Price	$0.04 per kWh
– Wires Charge Set by the Commission	$0.01 per kWh

After End of Year – Market Price is Higher Than Projected by SCC

– Capped Generation Rate	$0.05 per kWh
– Actual Market Price During Year	$0.045 per kWh

–	Wires Charge based on Actual Market Price	$0.005 per kWh
–	Wires Charge Set by the Commission	$0.010 per kWh
–	Over-recovery	$0.005 per kWh

After End of Year – Market Price is Lower Than Projected by SCC

–	Capped Generation Rate	$0.05 per kWh
–	Actual Market Price During Year	$0.035 per kWh
–	Wires Charge based on Actual Market Price	$0.015 per kWh
–	Wires Charge Set by the Commission	$0.010 per kWh
–	Under-recovery	$0.005 per kWh

Response to Question 4. The Company's responses to the questions above describe the methodology and steps for recovering stranded costs through the wires charge mechanism. Additionally, as recognized in § 56-584, capped rates revenues also can provide a means for mitigation of potential stranded costs, for example, buy-outs of NUG contracts and write-off of regulatory assets. However, it must be emphasized that the primary function of a utility's capped rate revenues is the continued safe and reliable provision of service to customers who have not switched to a CSP (i.e., its cost of service).

Dominion Virginia Power has significant potential stranded cost exposure and is seeking to mitigate such costs through buy-outs of above-market power purchase contracts as funds become available, by lowering other costs, and by improving operational efficiencies where possible. At the same time, the Company continues to incur new obligations relating to environmental compliance and major maintenance projects that cannot be passed on to customers under the rate cap. Whether future wires charges and funds available from capped rates will result in adequate recovery depends upon a number of factors and, particularly, market prices. Since 1999, market prices for electricity have fluctuated significantly and will likely continue to be volatile. The Act's approach to stranded cost recovery strikes a balance between utilities and customers. It also eliminates projections and the associated risk of incorrect data input and assumptions. Whether the methodology implemented by the Act will permit full mitigation of stranded costs depends upon a number of factors that cannot be finally determined until the recovery period ends on July 1, 2007.

Response to Question 5. The calculation and recovery of stranded costs through wires charges may produce an over-recovery or an under-recovery of stranded costs in any particular year. However, for the reasons stated above, an over-recovery or under-recovery of the Company's system or jurisdictional stranded costs through that wires charge mechanism and any additional funds applied to stranded costs mitigation measures from capped rate revenues cannot be finally determined until after July 1, 2007. Such over- or under-recovery will be highly dependent upon the accuracy of the projected market prices of generation and resultant wires charges set annually by the Commission.

Response to Question 6. "When the language of a statute is plain and unambiguous, we are bound by the plain meaning of that statutory language." *Lee County v. Town of St. Charles*, 264 Va. 344, 348, 568 S.E.2d 680, 682 (2002); *Industrial Dev. Auth. v. Board of Supervisors*, 263 Va. 349, 352, 559 S.E.2d 621, 623 (2002); *Cummings v. Fulghum*, 261 Va. 73, 77, 540 S.E.2d 494, 496 (2001); *Vaughn, Inc. v. Beck*, 262 Va. 673, 677, 554 S.E.2d 88, 90 (2001). The phrase "consistent with the provisions of the Act" is plain and unambiguous language, and therefore does not require further interpretation. Indeed, the legislative background of the Act, the Commission's implementation of the Act, and the explicit requirement in § 56-595 that the LTTF monitor the recovery of stranded costs as provided in § 56-584, guide and constrain the actions of the work group. Unless the Commission is wrong in its interpretation and implementation – and, to the Company's knowledge, no one has made such claim – the methodology in the 2001 and 2002 Wires Charges Final Orders accomplishes what the Act requires.

Response to Question 7. The Company, in the 1996 Cases[3], filed a transition cost report. This report was not a stranded cost study but a proposed methodology with an analysis presented for illustrative purposes based on a given set of assumptions. The methodology in the report showed \$3.2 billion in stranded costs on a system basis (\$2.5 billion on a Virginia jurisdictional basis).[4] Since that filing, the Company has not performed stranded cost studies except as provided for in the Act and as implemented by the Commission. The Company, however, has conducted two high-level studies that show above market costs for the NUG contracts. These studies, which were conducted in early 2002 and again in early 2003, were intended to give an order of magnitude assessment. The studies do not contain the detailed data inputs and assumptions contained in the 1996 Cases, but continue to show – as the Commission has found in the 2001 and 2002 Wires Charges Final Orders – that the Company has considerable stranded cost exposure.

Response to Question 8. Until July 1, 2007, the Company can calculate the amounts it has expended to mitigate potential stranded costs (less any additional expenditures that negatively impact such costs) and its over-recovery or under-recovery of net just and reasonable stranded costs. During that time, the Commission's implementation of the Act allows the General Assembly and, particularly, the LTTF, to monitor the Commission's estimate of

[3] *Virginia Electric and Power Company, 1995 Annual Information Filing and Commonwealth of Virginia at the relation of the State Corporation Commission, Ex Parte: Investigation of Electric Utility Industry Restructuring – Virginia Electric Power Company*, Case Nos. PUE-1996-00036 and PUE-1996-00296, 1998 S.C.C. Ann. Rept. 322 (August 7, 1998) ("1996 Cases").

[4] The General Assembly rejected the quantification approach, such as proposed in the transition cost report, in favor of the "lost revenue" approach as described in Appendix A.

potential stranded costs on an annual basis. It also allows Dominion Virginia Power to calculate net stranded cost exposure and its over-recovery or under-recovery for each annual period.

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APPENDIX A

Legislative Background of Stranded Costs in the Virginia Restructuring Act

Introduction:

This document traces the development of the treatment of stranded costs in the Virginia Electric Utility Restructuring Act. A review of the extensive effort by the joint subcommittee established under SJR 91 and the legislative history of the Restructuring Act (SB 1269) shows why up-front calculations and asset-valuation as means of quantifying stranded costs were deliberately rejected in favor of the approach used in the Act.

SCC Statements on Stranded Costs, Late 1990s: Up-front Quantification a "Recipe for Disaster"

During the intensive regulatory and legislative studies conducted in the years preceding passage of the Virginia Electric Utility Restructuring Act, the State Corporation Commission and its staff consistently warned against attempts to quantify stranded costs. The SCC warned that such activities may be "a recipe for disaster" (Draft Working Model for Restructuring the Electric Utility Industry in Virginia, November, 1997 at p. 88, hereinafter Draft Working Model, November 1997) and as an exercise that could "unintentionally undermine the ultimate objective" (SCC Draft Stranded Costs Benefit Legislation, July, 1998, at p. 1, hereinafter SCC Draft, July, 1998) of electric competition.

In various reports and submissions to the SJR 91 Joint Subcommittee, the SCC and its staff said administrative determinations of stranded costs would be extremely inaccurate for the following reasons:

- Such determinations would be extremely sensitive to unpredictable future changes in electricity market prices. The SCC observed that "long-term market prices of a sensitive, non-storable essential product with highly volatile weather-sensitive demand cannot be estimated within the bounds of reasonable accuracy." (SCC Draft, July, 1998, at p. 2) A deviation of plus or minus 15 percent from projected market prices could "either double or eliminate a $2.5 billion base estimate of stranded costs" (SCC Draft, July, 1998, at p. 2).

- Administrative determinations would also rely on inaccurate and unpredictable projections of the cost of existing assets. The projections, in some cases, would have to extend decades into the future, since some "existing utility assets may have a remaining useful life of over 30 years." (SCC Draft, July, 1998, at p. 2) Factors such as potential life-extensions of assets and new environmental upgrades would further complicate the calculations, according to the Commission's July 1998 submission.

- Economic models used in administrative stranded costs determinations are unrealistic, severely flawed and unreliable. "The economic model upon which most of these market price projections appear to be based is the perfectly competitive model where prices approach marginal costs" (Draft Working Model, November, 1997, at p. 89), the SCC staff said.

- Divestiture – the method of stranded costs quantification favored by some other restructuring states – would not accurately determine such costs. Mandated divestiture was a "drastic action . . . very difficult, probably impossible to undo" and might lead to sale prices that did not accurately reflect the assets' real value, according to SCC Director of Economics and Finance Richard J. Williams. (Presentation to the Task Force on Stranded Costs and Related Issues, by Richard J. Williams, May 26, 1998, at p. 10, hereinafter Presentation to the Task Force, May 26, 1998.)

While denouncing rigid, up-front calculations, the SCC's July 1998 draft legislation argued that stranded costs recovery mechanisms must be marked by "reasonable and necessary flexibility." (SCC Draft, July, 1998, at p. 1) The Commission staff also endorsed the "lost revenue" theory of stranded costs by offering the opinion that such costs do not exist in the absence of competition. The clearest statement of this theory was offered by Williams in his May 1998 remarks: "There can be no stranded costs until there is competition. As long as the strandable costs are in the utility's rate base and are included in the rates charged customers, nothing has been stranded and the utility is being fully reimbursed for the assets it uses to provide service." (Presentation to the Task Force by Richard J. Williams, May 26, 1998, at p. 2.)

A more complete record of SCC-related statements regarding issues concerning up-front administrative calculations of stranded costs is found in **Attachment A** to this document.

SJR 91 Joint Subcommittee: Legislative Development of Stranded Costs Concepts

After the 1998 passage of House Bill 1178 committing Virginia to electric supply competition, the SJR 91 joint subcommittee studying the restructuring process began an effort to develop a comprehensive electric deregulation bill. One of its first actions after conclusion of the 1998 session was appointment of a Stranded Costs and Related Issues Task Force, chaired by Sen. Richard Holland (D-Windsor) and Del. John Watkins (R-Chesterfield). The task force, the joint subcommittee, and later a drafting panel appointed by the subcommittee conducted an exhaustive review of the stranded costs issue, solicited input from a full range of stakeholders, and evaluated a variety of definitions and recovery mechanisms. The findings of the legislative groups operating under SJR 91 in large measure determined many of the stranded costs recovery mechanisms found in the Restructuring Act.

Work of Stranded Costs and Related Issues Task Force – May-October 1998

The task force met from May through October 1998 and collected information, opinions and suggestions from a variety of stakeholders, ranging from incumbent utilities to consumer groups. The SCC and the Virginia Attorney General's Division of Consumer Counsel also participated in the deliberations.

Although there were considerable differences of opinion at times among the stakeholders, the task force reported the following consensus regarding the elements of stranded costs. According to the consensus, stranded costs included:

- Generation asset devaluation;

- Potential losses associated with above-market, purchased power contracts (including cooperatives' wholesale power contracts); and

- Regulatory assets defined as "previously deferred, generation-related costs or obligations incurred by a regulated electric utility in providing electricity prior to generation deregulation." ("Report of the Joint Subcommittee Studying Restructuring of the Electric Utility Industry to the Governor and the General Assembly of Virginia," p. 13, hereinafter Report of the Joint Subcommittee.)

A November 2002 staff report to the Legislative Transition Task Force sheds more light on the SJR 91 deliberations regarding stranded costs. The 2002 report noted that the question of when costs become stranded prompted a wide range of opinions from stakeholders. For example, the Office of the Attorney General, Division of Consumer Counsel, noted that no stranded costs or benefits can exist "unless and until there is effective competition in the retail electric generation market and customers leave their current provider in favor of a competitor." ("Quantifying Incumbent Electric Utilities' Stranded Costs, Report to the Legislative Transition Task Force," November 19, 2002, p. 3.) This position is similar to the SCC staff view, voiced in May, 1998, that no stranded costs can exist until customers switch.

Regarding stranded costs collection mechanisms, the task force found general support for wires charges and capped or frozen rates. (Report of the Joint Subcommittee, p. 14.) This reflected a general acceptance of the "lost revenue" approach to stranded cost recovery. There was less agreement on the recovery period during which capped rates and wires charges would apply. Recovery periods ranging from three to 12 years were recommended by various stakeholders. (Report of the Joint Subcommittee, p. 14.)

The SJR 91 task force reported that most stakeholders agreed that "neither stranded costs nor stranded benefits can be calculated in advance of restructuring. The key variable - market prices for generation – is indeterminate until a competitive market for such generation exists in fact." (Report of the Joint Subcommittee, p. 13.) The final report also stated that stakeholders "agreed that the State Corporation Commission should play a significant role in addressing stranded costs and stranded benefits" (Report of the Joint Subcommittee, p. 14), but there was a wide divergence of opinion on what that role would incorporate. For example, an SCC submission to the SJR 91 task force in the fall of 1998 suggested that the Commission should "determine and quantify stranded costs and benefits." Most electric utilities, on the other hand, did not endorse an up-front stranded costs calculation. ("Draft Matrix, SJR 91 Stranded Costs and Related Issues Task Force," October 1998.)

By late 1998, therefore, the restructuring subcommittee was well aware of the dangers and complexities of attempting to make formal stranded costs calculations part of a state restructuring plan.

Virginia Electric Utility Restructuring Act embodies consensus on stranded cost recovery.

In November and December of 1998, the joint subcommittee's drafting group put together the main components of restructuring legislation. This process involved solicitation of legislative language from all interested stakeholders. Regarding stranded costs, the working draft contained the concepts of capped rates and wires charges and thereby reflected a centering on the "lost revenue" approach. But, despite the extensive work of the Stranded Cost and Related Issues Task Force, consensus had not yet been found on the stranded cost issue. It therefore became one of the issues to be addressed by the full joint subcommittee meeting as a "drafting group of the whole." The subcommittee did, however, take the significant step of rejecting a proposal that going-in rate cases must be conducted to set the rate caps. Such rate cases would have necessitated an attempt to quantify the stranded cost exposure of incumbent utilities. Rate caps were instead set by settlements achieved under alternative rate plans.

A collaborative process among stakeholders addressed stranded costs.

When the joint subcommittee met during the session on January 18, 1999, a substitute addressing stranded costs was offered by a coalition of stakeholders that met to resolve the stranded cost issue. This coalition included, among others, Virginia Power, AEP, ODEC, independent power producers, the Attorney General's Office of Consumer Counsel, ALERT and the Virginia Committee for Fair Utility Rates. Their proposal incorporated concepts that had been previously advocated by various stakeholders. This involved a definite transition period with capped rates and a non-by-passable wires charge to allow incumbent utilities to recover stranded costs. Consistent with the prior decision of the subcommittee that rejected going-in rate cases, it did not require any front-end quantification of such costs. This outcome satisfied to a great extent the concerns and interests of virtually all stakeholders. It afforded consumers protection from market volatility while providing incumbent utilities an opportunity to recover stranded costs. Through the wires charge as calculated in the bill, incumbent utilities are held financially harmless when their customers switch to another supplier and this helped overcome any resistance that incumbents might have in providing retail choice.

General Assembly reaffirmed stranded cost approach

The joint subcommittee adopted the coalition's substitute, as well as other amendments, and this became part of the restructuring bill introduced by Senator Norment as SB 1269. As this bill worked its way through the General Assembly, numerous amendments were made to clarify intent, accommodate differences among types of incumbent utilities, protect consumers, and provide legislative oversight. The fundamental method of addressing stranded costs, however remained intact. A test of this occurred when an amendment was attached to the bill in the House Commerce, Insurance and Banking Committee that would have required quantification of stranded costs in order to determine if these costs were over-recovered or under-recovered. When the bill reached the House floor, this language was rejected and instead, the Legislative Transition Task Force was directed to monitor whether the recovery of stranded costs, **as provided in 56-584**, is likely to result in over-recovery or under-recovery.

An examination of the debate on the floor of the House of Delegates on whether to strip the amendment proposed in the House Commerce, Insurance and Banking Committee supports the proposition that the House of Delegates clearly rejected a policy that required a quantification of stranded costs.

The Restructuring Act's stranded cost provisions are inextricably linked

Most importantly from the standpoint of the stranded cost issue is the fact that these components of the bill are mutually dependent and inextricably linked. The capped rate protects consumers from price spikes while giving utilities needed certainty with regards to revenue during a transition period. The market prices projected annually by the SCC enable wires charges to be calculated using the capped rate and facilitate choice by giving consumers a "price to beat." The capped rate period from January 1, 2001, to July 1, 2007, provides a reasonable time for consumers and utilities to adjust to competition and is critical in terms of utility recovery and mitigation of stranded costs. The Act works with each component performing more than one critical function and these functions are interdependent. This means that disturbing any one vital part will disrupt the whole mechanism. The beauty of this design is that no absolute quantification of stranded costs is intended or needed.

The stakeholders and the General Assembly were satisfied with this arrangement as reflected in both testimony in support of the bill and the large majority by which it was approved in both houses. To revisit the treatment of stranded costs in SB 1269 by isolating it and attempting to quantify it would disrupt the foundation of the Restructuring Act and would ignore the concurrence of the stakeholders and the wisdom of the General Assembly in addressing this issue.

Conclusion:

The reasons for rejection of quantification of stranded costs in the language of the Restructuring Act remain valid today. Stranded costs are dynamic quantities that constantly fluctuate and there was, and is no, consensus on the correct means of calculation. The Act provides a workable method that is adjusted annually, and a reasonable period for stranded cost recovery that was negotiated, agreed upon, and settled in 1999.

ATTACHMENT: State Corporation Commission Comments on Stranded Costs Recovery, 1997-98

ATTACHMENT

State Corporation Commission Comments on Stranded Costs Recovery, 1997-98

Comments from "Draft Working Model for Restructuring the Electric Utility Industry in Virginia," November 1997

Up-front calculations "a recipe for disaster"

"To the extent public policy provides for some recovery level of stranded costs and stranded margins, policy implementation will be extremely complex. As indicated previously, stranded costs and margins are dynamic since they are directly dependent on the future market prices of electricity over the remaining life of the utility's generation-related assets. Any policy implementation which locks in stranded cost recovery up-front based on projections of long-range market prices for a market structure that does not currently exist may be a recipe for disaster." (Draft Working Model, p. 88.)

Sensitivity to market prices

"The dangers of a one-time administrative determination of stranded costs and margins should be made evident by Virginia Power's recent alternative regulatory plan filing with the Commission in Case No. PUE960226. In the filing, the Company provides an example stranded cost calculation under a given set of assumptions which reveals an approximate Virginia jurisdictional stranded cost exposure of $2.5 billion. However, a change in projected market prices of 15%, up or down, could either eliminate or double, respectively, the stranded cost calculation." (Draft Working Model, p. 88.)

Reliance on flawed assumptions, models

"Staff is especially concerned that current estimates of long-term market prices may be biased to the downside, thereby resulting in overestimation of stranded costs or underestimation of stranded margins. First, the Staff believes that there is a natural tendency of long-term projections to be unduly influenced by perceptions of current conditions, in this case the perception of excess capacity reserves and depressed electricity market prices. Secondly, the economic model upon which most of these market price projections appears to be based in the perfectly competitive model where prices approach marginal costs. This perfectly competitive model assumes that producers are price takers and fails to recognize many of the potential market aberrations that may characterize a competitive electric generation industry." (Draft Working Model, pp. 88-89.)

Divestiture unreliable in quantifying stranded costs

"An alternative to administratively calculating stranded costs is to require or encourage the sale of generating assets, thereby allowing the market to directly assess the value of those assets…However, in addition to being a rather drastic action for purposes of determining stranded cost, the Staff believes there is a significant risk that the short-term bias of the market might undervalue capacity, given the current perceptions of excess capacity. A large amount of generation capacity offered for sale at one time could further exacerbate this effect and result in higher stranded cost than might truly be justified." (Draft Working Model, p. 90.)

Comments from "Presentation to the Task Force on Stranded Costs and Related Issues" by Richard J. Williams, Director of Economics and Finance, State Corporation Commission, May 26, 1998

Erroneous estimates "could prove disastrous"

"Those types of possibilities beg for the greatest amount of flexibility possible to be built into the process for determining stranded costs. I hope you don't mind my making a brief editorial comment, but policy implementation which locks in stranded cost recovery based on long-range forecasts of market prices under a market structure that does not currently exist could prove disastrous." (Williams' comments, p. 10.)

Extreme sensitivity to market prices poses barrier to successful calculations

"In particular, it will be very difficult to administratively calculate stranded costs and stranded benefits. As previously discussed, stranded costs or benefits are the difference between regulated, embedded-cost rates for electricity and competitive market prices. Their calculation will require a forecast of what the embedded cost of existing generating assets would be over the life of the assets as if regulation continued and then discounted back to today's present value. We would have to compare this forecast to another forecast of what the market price of electricity would will be over the same time frame, once again discounted back to the present.

"I don't think I have to tell you the number of assumptions that would be involved in each of those calculations...A change in the projected market price of 15 percent up or down could either eliminate or double the stranded cost calculation." (Williams' comments, pp. 8-9.)

"Lost revenue" approach to stranded costs endorsed

"First, stranded costs are actually a reclassification of existing costs, they are not a new cost. The costs that may potentially be stranded are reflected in current electric rates. Regulated rates are based upon the actual cost of providing electric service. The assets that are in danger of becoming stranded are sometimes referred to as strandable costs.

"That brings me to fact number two: there can be no stranded costs until there is competition. As long as the strandable costs are in a utility's rate base and are included in the rates charged customers, nothing has been stranded and the utility is being fully reimbursed for the assets it uses to provide service." (Williams' comments, p. 2.)

Comments from introduction to "SCC Draft Stranded Costs/Benefits Legislation," July 1998

Flexible recovery method necessary

"If the General Assembly decides that at least some portion of stranded costs should be recoverable, we suggest a legislative approach to the determination and recovery of such costs that is specifically aimed at maintaining reasonable and necessary flexibility with respect to policy implementation and administration. We believe that this flexibility is critical to serving the public interest of Virginia in that such a process entails substantial complexity and uncertainty, poses potentially significant public impacts, and must address the unique circumstances of each utility...It is essential that rigidity not be incorporated in one component of the transition process that may unintentionally undermine the ultimate objective." (Draft SCC submission, p. 1.)

Stranded costs hard to calculate

"Stranded costs and benefits are dynamic and cannot be accurately determined at this time, or even closely approximated. Proper estimation of stranded costs and benefits requires projecting market prices and costs over the remaining useful life of each existing asset or contract. In some cases existing utility assets may have a remaining useful life of over 30 years." (Draft SCC submission, p. 2.)

"Long-term market prices of a sensitive, non-storable essential produce with highly volatile weather-sensitive demand, simply cannot be estimated within the bounds of reasonable accuracy." (Draft SCC submission, p. 2.)

"A 15 percent change in market prices in an example stranded cost calculation provided by one utility would either double or eliminate a $2.5 billion base estimate of stranded costs. Cost projections of existing assets are also extremely questionable due to factors such as potential life-extensions and significant new environmental regulations with disparate impacts. An additional complication will be the allocation of embedded costs between competitive services and services which may continue to be subject to some form of price regulation such as certain generation-related ancillary services or must-run units.

"In short, reliance on a one time up-front estimate of stranded costs and benefits presents the potential for a public policy disaster," the introduction concluded. (Draft SCC submission, p. 2.)

#153644

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
at Richmond

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STATE CORPORATION COMMISSION	)	**Case No. PUE-2003-00062**
	)	
In the matter of Developing	)	
Consensus Recommendations on	)	
Stranded Costs	)	

RESPONSES TO THE COMMISSION INQUIRIES

Pursuant to the Virginia State Corporation Commission's ("Commission") March 3, 2003, *Order Establishing Proceeding*, A&N Electric Cooperative, BARC Electric Cooperative, Community Electric Cooperative, Mecklenburg Electric Cooperative, Northern Neck Electric Cooperative, Northern Virginia Electric Cooperative, Prince George Electric Cooperative, Rappahannock Electric Cooperative, Shenandoah Valley Electric Cooperative and Southside Electric Cooperative, Inc., the Virginia distribution cooperative members of Old Dominion Electric Cooperative (collectively, the "Cooperatives" or "Old Dominion Cooperatives") hereby join in filing these *Responses to the Commission Inquiries* in this proceeding.[1]

I. Introduction

On March 3, 2003, the Commission entered its aforementioned *Order Establishing Proceeding* creating this proceeding in response to the resolution adopted on January 27, 2003, by the Virginia General Assembly's Legislative Transition Task Force ("LTTF"). That

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1 These responses to the Commission's questions are offered on behalf of and represent the collective interests of the Old Dominion Cooperatives. Certain of the Cooperatives may also file responses and participate in this proceeding to present their individual concerns.

resolution directs the Commission to form a work group to develop certain consensus recommendations, consistent with the provisions of the Virginia Electric Utility Restructuring Act ("Restructuring Act"), §§ 56-576 *et seq.* of the Code of Virginia ("Code"), with regard to "stranded costs." The first meeting of the work group is to convene on April 1, 2003.

The initial task of the work group is to prepare a report to the LTTF presenting the group's consensus recommendations regarding the definition of "stranded costs" and "just and reasonable net stranded costs." The report also is to include consensus recommendations regarding a methodology to calculate each incumbent utility's just and reasonable net stranded costs, to measure the amounts recovered to offset such costs and to determine whether such recovery will result in over- or under-recovery of the net stranded costs.

In order to start the process and to begin framing issues for the work group discussions, the Commission requested that interested persons respond to any or all of eight questions the Commission posed relative to the description and calculation of stranded costs. The following are the Old Dominion Cooperatives' responses to several of the Commission's questions, and other pertinent remarks.

II. Discussion

1. *Define "stranded costs." Include in the definition a detailed listing of each stranded cost component. Is this definition applicable to all electric utilities operating in Virginia? If not, to which utility or utilities does it apply and why?*

While the term "stranded costs" and the concept of "costs stranded" are used in the Code of Virginia (*see* Va. Code § 56-584 and § 56-235.7), neither the term nor the concept are defined anywhere in the Code. Much as the Code describes "default service" only in terms of what customers can receive it (*see* Va. Code § 56-585), stranded costs (expanded to "just and reasonable net stranded costs") are described only in terms of by whom and how such costs may be recovered. Otherwise, the term "stranded costs" remains undefined.

Based on the manner in which the General Assembly (with the support of most stakeholders) elected to address stranded costs, this was the best approach. After wrangling with the concept over many months, the participants in the process settled on a "lost revenue" approach to the recovery of such costs (based on capped rates and wires charges). This approach obviates the need for a meaningful statutory definition of the term "stranded costs." As the Commission recently observed, "wires charges serve as a 'proxy', on a utility by utility basis, of stranded costs. Therefore, no actual determination of stranded costs is necessary as a precondition of receipt of wires charges." [2] In essence, consistent with the approach selected by the General Assembly and included in the Restructuring Act, no definition of stranded costs is necessary.

If a definition is sought, number of sources could be examined for a definition of the term "stranded costs." For purposes of this proceeding, however, the best source for guidance as to how the term may have been defined (if a definition was needed) would be the comments submitted and testimony provided to the Task Force on Stranded Costs and Related Issues of the General Assembly's Joint Subcommittee Studying Electric Utility Restructuring in 1998. A number of definitions were proposed by stakeholders for consideration by that Task Force. Perhaps first and foremost among those definitions was that offered by Mr. Richard J. Williams, the Commission's long-time Director of Economics and Finance, on May 26, 1998. As Mr. Williams stated:

> Stranded costs will occur if there is a net loss in economic value of existing generation-related utility assets and contracts resulting from a restructured

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2 *Application of Northern Virginia Electric Cooperative for review of tariffs and terms and conditions of service*, Case No. PUE-2002-00086, *Final Order* at n.3 (June 18, 2002).

> industry. The change in economic value will be based upon the difference between embedded-cost electricity rates calculated under regulation and competitive market-based electricity prices.

Mr. Williams also offered additional guidance on the concept of stranded costs. First, he stated that stranded costs are not a new cost; they are a reclassification of existing costs, costs that are reflected in current electric rates. Second, there can be no stranded costs until there is competition. As long as the costs remain in a utility's rate base and are included in the rates charged customers, nothing has been stranded and the utility is being fully reimbursed, through its cost-of-service based filed rates, for the assets it uses to provide service. Finally, Mr. Williams noted that stranded costs are related exclusively to generation assets.

The Cooperatives generally agreed with the definition of and flexible approach to stranded costs advocated by Commission Staff. In comments to the Task Force, the Cooperatives defined stranded costs as an incumbent electric utility's:

> electric generation-related costs, reasonably and prudently incurred in meeting its public service obligations … that would be recoverable under traditional cost-of-service regulation but which may not be recoverable in a competitive electric generation market ….

Regarding the components of stranded costs, the Cooperatives listed: (1) net generation plant investments and costs attributable to investment in generation plant and related facilities (including transmission interconnection costs); (2) projected nuclear plant decommissioning costs, spent nuclear fuel disposal costs and projected retirement costs of non-nuclear plants; (3) costs attributable to purchase power contracts; and (4) other similar or related costs determined by the Commission. In his comments to the Task Force, Mr. Williams also described several components or sources of stranded costs. He recognized existing utility-owned generating units, existing wholesale power contracts and regulatory assets (deferred expenses authorized by a regulatory agency) as potential sources of stranded costs.

In summary, consistent with the Restructuring Act, the term "stranded costs" could be defined as follows:

> Stranded costs are costs that arise if there is a loss in economic value of existing generation-related utility assets and contracts, owing to costs incurred in meeting an incumbent electric utility's public service obligations that would be recoverable under traditional cost-of-service regulation but which may not be recoverable in a competitive electric generation market. The change in economic value is measured by the difference between embedded generation costs (with fuel adjustments) as calculated under regulation and competitive market-based generation costs.

2. *Define "just and reasonable net stranded costs." Provide a detailed explanation of how and why it differs from "stranded costs." Is this definition applicable to all electric utilities operating in Virginia? If not, to which utility or utilities does it apply and why?*

In the draft legislation provided to the Task Force by Commission Staff in 1998, the following definition for "net stranded costs" was offered:

> "Net stranded costs" means the jurisdictional amount of verifiable, prudent, and necessary book costs ... of the total net asset investments and financial obligations of an electric public utility, considered as a whole, which the Commission finds:
>
> (1) cannot or are not likely to be recovered by the utility from the competitive market, or decreased through prudent and effective efforts of the utility, over the remaining useful life of such assets and obligations;
>
> (2) have resulted from prior legal or regulatory obligations of a utility to provide a service which the General Assembly declares, or the Commission finds, to be a competitive service ...; and
>
> (3) are properly allocable to such service.

Since that definition makes reference to the costs being "verifiable, prudent and necessary," such costs by implication would be considered just and reasonable.

Two factors appear to drive any suggested distinction between "stranded costs" and "just and reasonable net stranded costs." Addition of the word "net" suggests that counterbalancing benefits or other offsets might be considered in determining stranded costs. Given that wires charges are calculated for each year of the transition period to retail competition, it could mean that in order to counterbalance an erroneous projection of the market price in one year, the wires charges from that year can be netted against another year to produce a more equitable total stranded cost figure.

Adding the term "just and reasonable" suggests that reasonableness and prudence demonstrated in generating power and controlling the cost of generation would be considered in evaluating the fairness of the overall stranded cost recovery. Taking reasonable and prudent steps toward reducing generation costs, thus mitigating stranded costs, should be encouraged and should accrue to the benefit of the incumbent electric utility. Decreasing costs through the prudent and effective mitigation efforts of the utility would serve to further offset stranded costs. Use of the term "just and reasonable" could mean that the incumbent utility's net stranded costs could be affected by its prudent and reasonable behavior, further distinguishing such stranded costs from the general notion of stranded costs.

In the Cooperatives' view, the term "just and reasonable net stranded costs" was offered principally to describe something different from "any and all" stranded costs. The term suggests that stranded costs are not simply an entitlement. Certain factors and behaviors by the incumbent utility can affect the total amount of stranded costs and stranded cost recovery. Based on the definition of "stranded costs" offered above, "just and reasonable net stranded costs" could be defined as:

> Costs that arise if there is a *net* loss in economic value of existing generation-related utility assets and contracts, owing to *reasonable and prudent* costs incurred in meeting an incumbent electric utility's public service obligations that would be recoverable under traditional cost-of-service regulation but which may not be recoverable in a competitive electric generation market. The change in economic value is measured by the *net* difference between embedded generation costs (with fuel adjustments) as calculated under regulation and competitive market-based generation costs.

This definition could be applied to the Cooperatives if and when there was a need to apply it, subject to the differences in determining the stranded costs of the Cooperatives described in the response to Question No. 8.

3. *Provide a methodology for calculating "just and reasonable net stranded costs." Be specific in providing the necessary steps, beginning with each component comprising gross stranded costs and each component offsetting this amount to reach a net amount.*

The Restructuring Act already provides a methodology for calculating just and reasonable net stranded costs. In Virginia, capped generation rates (based on just and reasonable filed rates previously approved by the Commission and unbundled in the Cooperatives' functional separation proceedings) that are to be held in place for a predetermined period allow for stranded cost recovery and serve to counterbalance stranded costs and benefits. This approach has also helped avoid the use of an unsupportable, inaccurate and potentially disastrous one-time prediction of total stranded costs and stranded cost recovery.

Consistent with the Restructuring Act, wires charges act as a proxy for stranded costs. The wires charge calculation represents the amount recovered for stranded costs. The calculation of wires charges changes from year to year based on the Commission's determination of the market rate for generation for the year. In some years the capped generation rate may exceed the Commission's market rate for generation and in other years the market rate may be higher. Reasonable and prudent actions to reduce costs come into consideration. Over the course of the transition to a competitive retail market, the wires charges collected in one year may be netted against the wires charges in another year, such that at the end the wires charges collected produce the net stranded costs recovered. Overall, this describes the elements included in the methodology for calculating "just and reasonable net stranded costs."

There is no need to describe components of a "gross stranded cost" and account for offsets to reach a "net stranded cost." In the system adopted in Virginia, the total wires charges collected, which will reflect certain offsets and mitigation, produce the net stranded costs.

4. *Describe how stranded costs are recovered. Provide a methodology for calculating such recovery. Describe the recovery period.*

Consistent with the Restructuring Act, stranded costs are recovered through the collection of wires charges. Other methods were considered and discussed by the participants in the legislative process, but in the end they were rejected in favor of the lost revenue approach followed to calculate and recover wires charges.

In his comments to the Task Force, Mr. Williams described two basic ways of calculating net stranded costs – administrative calculation using forecasting and modeling, and market valuation through divestiture of generating assets. While Mr. Williams found that divestiture had an immediate appeal, he concluded it would be too drastic a course of action, one that probably would be impossible to undo if the competitive market failed to develop. Mr. Williams saw that dependence on an administrative determination also had its drawbacks, but his preference was for a flexible administrative process that did not lock in stranded cost recovery based on long-term market projections in a non-existent market, which he suggested could prove disastrous.

Subsequent comments and legislative proposals from the Commission continued to support this approach to stranded costs. In comments and draft legislation submitted to the Task Force by Commission Staff, Staff noted that stranded costs and benefits are dynamic and could not be even be closely approximated because the necessary supporting assumptions and data simply could not be estimated with any reasonable accuracy. In Staff's view, reliance on a one-time, up-front stranded cost estimate presented the potential for a *public policy disaster*.

Ultimately, Commission Staff's comments called for "maximum implementation flexibility ... in view of: 1) the uniqueness of circumstances faced by each utility and its customers; 2) the significant complexity and uncertainty surrounding the determination and recovery of stranded costs and stranded benefits; 3) the evolutionary and dynamic nature of electric industry restructuring; and, 4) the potentially substantial public interest impact of such policy." Recommendations like these led to the approach to stranded costs adopted by the General Assembly, basing the recovery of such costs on an administrative determination of revenues lost, using capped rates and an annual market rate determination (with fuel adjustments) to calculate wires charges that would serve as a proxy for stranded costs.

The Cooperatives support the approach adopted by the Commission in its proceeding establishing generation market price methodologies for purposes of establishing wires charges.[3] As noted by the Commission, "the wires charge stranded cost recovery mechanism set forth in the Act essentially makes the incumbent electric utility indifferent as to whether a customer elects to receive electric service from a CSP or remain a generation customer of the incumbent."[4] In the market rate proceeding, the Commission described the method for recovering stranded costs during the transition period:

> When a customer formerly served by an incumbent electric utility takes electric generation service from a CSP, then incumbent retains control of the electric generation that formerly served the departing customer. Under the Act, this "displaced power" is assumed sold by the incumbent into the wholesale power market. The wires charge mechanism compares the value of this electric generation, as measured by the revenue accruing from the sale adjusted for net transmission costs, to the revenue that the incumbent would have collected from the departed customer. Should the expected revenue garnered from the wholesale sale be less than the retail revenues that would have been collected from the departing customer, the difference between these two values represent wires

[3] Ex Parte: *In the matter considering requirements relating to wires charges pursuant to the Virginia Electric Utility Restructuring* Act, Case No.PUE-2001-00306, *Final Order* (October 11, 2002).

[4] *Id.* at 4.

charge revenues. … [T]he wires charge collection is designed to leave the incumbent indifferent between these two revenue streams.[5]

While the method described is not directly applicable to the Old Dominion Cooperatives, consistent with the terms of the Restructuring Act it is indirectly applicable to them. The Cooperatives find it to be a workable and understandable approach to stranded costs and endorse its continued use.

5. *Requested Actions paragraph 1 of the LTTF Resolution requests that the work group develop consensus recommendations "consistent with the provisions of the Act." Explain how that phrase guides or possibly constrains the actions of the work group. Identify each section of the Virginia Electric Utility Restructuring Act, §§ 56-576 to -596 of the Code of Virginia, pertinent to such guidance or constraint. Additionally, explain each such section's significance in the context of definitions offered in response to questions 1 and 2 as well as in the methodologies proffered for calculating and recovering just and reasonable net stranded costs in response to questions 3 and 4.*

The Cooperatives do not believe there is much mystery in the statement "consistent with the provisions of the Act." It appears that the LTTF is attempting to determine if there is a consensus view with regard to the proper interpretation of the Restructuring Act, in its current form, relative to stranded costs. Thus far, in considering restructuring, the Commission has been successful in making policy and providing interpretations "consistent with the provisions of the Act."

8. *Provide any additional comments on the issues raised by Requested Actions paragraphs 2 and 3 of the LTTF Resolution.*

Regarding the question of whether the definitions apply to all electric utilities operating in Virginia, while the Cooperatives have never argued that the definition or components of stranded costs should be different as applied to them, the Cooperatives did seek different *treatment* with regard to stranded costs. Two factors, one applicable to cooperatives in general

5 *Id.* at 5.

and one applicable to the Old Dominion Cooperatives in particular, create the need for a differentiated approach with regard to the Cooperatives' stranded costs.

First, for a cooperative, full stranded cost recovery is a vital concern because, unlike the investor-owned utilities, stranded costs cannot be shared with or shifted to anyone other than its consumers. While the IOUs have stockholders to bear any loss associated with any stranded costs not recovered, a cooperative's customers and owners are one in the same. Any failure to fully recover stranded costs will adversely affect the cooperative's member/consumers. At the same time, there is less concern about a cooperative recovering excess stranded costs because cooperatives operate on a not-for profit basis. Any revenues above costs collected by a cooperative will be returned to its member/consumers, either as a refund of patronage capital or a year-end margin adjustment.

In addition, as has been recognized in the Restructuring Act, the relationship between the Old Dominion Cooperatives and their exclusive power supplier, Old Dominion, creates unique issues concerning stranded costs. If retail competition leads to the loss of load at the distribution cooperative level, Old Dominion may have stranded costs. Stranded costs attributable to one cooperative could be shifted to another cooperative if stranded costs are not properly addressed. For the Old Dominion Cooperatives, stranded costs must be a coordinated such that Old Dominion stranded costs are attributed to and collected by the member cooperative responsible for the stranded costs, then passed back up to Old Dominion. Section 56-584 includes a provision to address these issues.

III. Conclusion

The Cooperatives respectfully offer these initial comments and responses to the Commission's questions relative to stranded costs. The Cooperatives look forward to working with the Commission, Commission Staff, the Office of the Attorney General and other interested parties in the work group assembled to assist Staff in developing a report to the LTTF regarding the definitions and components of stranded costs and the effect of stranded costs on restructuring in Virginia.

Respectfully submitted,

By: ______________________________

Counsel for A&N Electric Cooperative,
BARC Electric Cooperative,
Community Electric Cooperative,
Mecklenburg Electric Cooperative,
Northern Neck Electric Cooperative,
Northern Virginia Electric Cooperative,
Prince George Electric Cooperative,
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March 21, 2003

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing *Responses to the Commission Inquiries* was hand-delivered or mailed, postage prepaid, this 21st day of March 2003 to the following members of Commission Staff:

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Re: Stranded Costs Working Group, Case No. PUE-2003-00062

Gentlemen:

On behalf of Appalachian Power Company, d/b/a American Electric Power ("Company"), enclosed are initial responses to the eight (8) questions listed in the Commission's "Order Establishing Proceeding" issued on March 3, 2003. Copies of this letter and the Company's responses to the questions (including attachments) have been sent to econfin@scc.state.va.us.

The Company's responses to the Commission's questions, in some cases, are based on a broad reading of the questions and, where appropriate, provide factual information more relevant to the implementation of stranded cost recovery generally, rather than specifically with respect to the Virginia Electric Utility Restructuring Act. The mix of specific references to the current Virginia restructuring statute and more broadly worded references to stranded costs /methodologies in the Commission's questions seemed to request information regardless of its technical relevance to issues under the current Virginia law.

The mix of considerations in the Commission's questions and the general complexity of the subject of stranded costs will require careful consideration by the Working Group. The subject is inextricably tied to the development and timing of competition in Virginia, and recent legislative developments may signal a change in Virginia's commitment to pursue competition as it has previously. These considerations will add to the complexity of the issues that the Working Group must face.

The Company would observe that the Virginia restructuring statute provides for a transition process under which stranded costs are recovered through a combination of capped rates and non-bypassable wires charges. There has been significant concern expressed by various parties that wires charges are inhibiting the development of retail competition in the Commonwealth. The Company acknowledges that wires charges, as prescribed by the Act, do have an impact on customer switching; however, other matters also affect whether or not customers switch. While still in the early phases of the transition period in Virginia, it is clear that additional changes will need to occur to create a robust competitive environment that provides the potential for customer benefits.

The Working Group deliberations on stranded costs will necessarily require the participants to maintain flexibility as they consider their initial responses to the questions and evolving positions on regulatory or legislative actions that might be proposed in Virginia. The Company looks forward to further participation in those deliberations in that spirit.

Sincerely,

Barry L. Thomas, Director
Regulatory Services VA/TN

BLT/cde

Virginia Stranded Cost Proceeding
Case No. PUE-2003-00062
Answers to SCC Questions Contained in its March 3, 2003 Order

Question No. 1

Define "stranded costs." Include in the definition a detailed listing of each stranded cost component. Is this definition applicable to all electric utilities operating in Virginia? If not, to which utility or utilities does it apply and why?

Question No. 2

Define "just and reasonable net stranded costs." Provide a detailed explanation of how and why it differs from "stranded costs." Is this definition applicable to all electric utilities operating in Virginia? If not, to which utility or utilities does it apply and why?

Response

In the context of electric utility industry restructuring generally, the term "stranded costs" refers to a range of costs not recoverable by an electricity utility in a competitive market. The three broad categories of stranded costs are generally identified as follows:

A. Production sources. This category can be further divided into two sub-categories:
   - Generation assets. Stranded costs in this sub-category consist of the difference between the market value of an electric utility's generation assets and the book value of those assets as of a certain date. Generation assets include all assets (i.e. not just physical plant) associated with the production of electricity.
   - Purchased power contracts. Stranded costs in this sub-category consist of the difference between the market value of an electric utility's long-term purchase power contracts and the book value of those contracts as of a certain date.

B. Generation-related regulatory assets. This category consists of deferred expenses reflected on an electric utility's balance sheet, as of a certain date, pursuant to a Commission order or practice, or to generally accepted accounting principles as a result of a prior commission rate making decision. Generation-related regulatory assets include but are not limited to such things as deferred taxes related to SFAS 109 and the unamortized costs of deferred expenses related to post-employment benefits.

C. Transition costs. This category reflects the costs associated with such things as implementing retail choice and providing employee assistance and consumer education programs.

The categories identified above encompass the broad range of stranded costs applicable to all electric utilities operating in Virginia. However, every Virginia electric utility may not necessarily incur costs in each category depending upon its specific circumstances. The definition of the term "just and reasonable net stranded costs" is dependent upon the methodology used to determine stranded costs.

Virginia Stranded Cost Proceeding
Case No. PUE-2003-00062
Answers to SCC Questions Contained in its March 3, 2003 Order

Question No. 3

Provide a methodology for calculating "just and reasonable net stranded costs." Be specific in providing the necessary steps, beginning with each component comprising gross stranded costs and each component offsetting this amount to reach a net amount.

Question No. 4

Describe how stranded costs are recovered. Provide a methodology for calculating such recovery. Describe the recovery period.

Question No. 5

Do the calculation and recovery methodologies described in the responses to questions 3 and 4 produce (or are they likely to produce) over-recovery or under-recovery of just and reasonable net stranded costs? How should such over- or under-recovery be dealt with?

Question No. 6

Requested Actions paragraph 1 of the LTTF Resolution requests that the work group develop consensus recommendations "consistent with the provisions of the Act." Explain how that phrase guides or possibly constrains the actions of the work group. Identify each section of the Virginia Electric Utility Restructuring Act. §§ 56-576 to –596 of the Code of Virginia, pertinent to such guidance or constraint. Additionally, explain each such section's significance in the context of definitions offered in response to questions 1 and 2 as well as in the methodologies proffered for calculating and recovering just and reasonable net stranded costs in response to questions 3 and 4.

Response

Although Section 56-584 of the Restructuring Act explicitly deals with the recovery of "just and reasonable net stranded costs," it does embody a methodology of estimating such costs.[1] "Just and reasonable net stranded costs" are recovered through a combination of revenues collected under capped rates established pursuant to Section 56-582 and any non-bypassable wires charges established by the Commission on an annual-basis pursuant to Section 56-583. The recovery period provided for under these sections of the Restructuring Act goes through the end of the capped rate period, which could extend through June 30, 2007.

[1] Appendix 1 sets forth the portions of the Restructuring Act that APCo has identified as pertinent to the phrase "consistent with the provisions of the Act" found in Requested Actions paragraph 1 of the LTTF's Resolution.

There are a number of alternative methodologies that can be used to calculate "just and reasonable net stranded costs". In the case of the first category of stranded costs, one way to determine "just and reasonable net stranded costs" is for the utility to sell its generation assets and purchased power contracts. The net difference between the sale price received for these assets and the book value of the assets as of the sale date equals the utility's "just and reasonable net stranded costs" for the production sources category.

The comparable transactions approach uses data from actual sales of generation assets to determine market value. Typically, this method compares unsold generation assets with "comparable" assets that have been sold, and then estimates the value of the unsold assets by assigning them the average value from the "comparable" sales.

Under a revenue-based or lost revenues approach, an electric utility is compensated for the loss in the value of its generation assets. Under this method, "just and reasonable net stranded costs" for the first category of stranded costs are reflected in the excess of the net book value of a utility's generation assets compared to the present value of projected future margins (cash flow) earned from those assets under market prices and reflecting future costs. This method recognizes the financial effect that every source of generation-related stranded cost has on the utility's assets, long-term contracts and transition costs. This approach is an administratively determined method of calculating stranded costs that requires many assumptions about several aspects of future market conditions and operations, including such things as environmental costs, coal and gas prices, the entry of new generation and asset utilization rates.

The methods discussed above also require a determination of "just and reasonable net stranded costs" associated with generation-related regulatory assets and transition costs. Given that regulatory assets, if any, appear on an electric utility's books, it is relatively easy to identify and value those costs. Because transition costs will occur over time, the same issues associated with projecting such future stranded costs are inherent in any methodology that requires a current estimate of "just and reasonable net stranded costs."

There are various methods available for the recovery of stranded costs. The most straightforward and generally accepted method utilizes some type of a non-bypassable surcharge per kWh of customer usage. Such a surcharge could be designed to collect a predetermined amount of stranded costs over a specified period of time (but by its very nature an estimated amount). Since such a design could require the use of projected kWh usage, the actual surcharge could be effective for a slightly shorter or longer period to account for variances between projected and actual kWh usage. The actual recovery from the surcharge could be tracked to prevent over- or under-recovery. In some states, securitization has been used as a recovery mechanism for stranded costs.

§ 56-581. Regulation of rates subject to Commission's jurisdiction.

A. Subject to the provisions of § 56-582, the Commission shall regulate the rates for the transmission of electric energy, to the extent not prohibited by federal law, and for the distribution of electric energy to such retail customers on an unbundled basis, but, subject to the provisions of this chapter after the date of customer choice, the Commission no longer shall regulate rates and services for the generation component of retail electric energy sold to retail customers.

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§ 56-582. Rate caps.

A. The Commission shall establish capped rates, effective January 1, 2001, and expiring on July 1, 2007, for each service territory of every incumbent utility as follows:

1. Capped rates shall be established for customers purchasing bundled electric transmission, distribution and generation services from an incumbent electric utility.

2. Capped rates for electric generation services, only, shall also be established for the purpose of effecting customer choice for those retail customers authorized under this chapter to purchase generation services from a supplier other than the incumbent utility during this period.

3. The capped rates established under this section shall be the rates in effect for each incumbent utility as of the effective date of this chapter, or rates subsequently placed into effect pursuant to a rate application filed by an incumbent electric utility with the Commission prior to January 1, 2001, and subsequently approved by the Commission, and made by an incumbent electric utility that is not currently bound by a rate case settlement adopted by the Commission that extends in its application beyond January 1, 2002. If such rate application is filed, the rates proposed therein shall go into effect on January 1, 2001, but such rates shall be interim in nature and subject to refund until such time as the Commission has completed its investigation of such application. Any amount of the rates found excessive by the Commission shall be subject to refund with interest, as may be ordered by the Commission. The Commission shall act upon such applications prior to commencement of the period of transition to customer choice. Such rate application and the Commission's approval shall give due consideration, on a forward-looking basis, to the justness and reasonableness of rates to be effective for a period of time ending as late as July 1, 2007. The capped rates established under this section, which include rates, tariffs, electric service contracts, and rate programs (including experimental rates, regardless of whether they otherwise would expire), shall be such rates, tariffs, contracts, and programs of each

incumbent electric utility, provided that experimental rates and rate programs may be closed to new customers upon application to the Commission. Such capped rates shall also include rates for new services where, subsequent to January 1, 2001, rate applications for any such rates are filed by incumbent electric utilities with the Commission and are thereafter approved by the Commission. In establishing such rates for new services, the Commission may use any rate method that promotes the public interest and that is fairly compensatory to any utilities requesting such rates.

B. The Commission may adjust such capped rates in connection with the following: (i) utilities' recovery of fuel costs pursuant to § 56-249.6, (ii) any changes in the taxation by the Commonwealth of incumbent electric utility revenues, (iii) any financial distress of the utility beyond its control, (iv) with respect to cooperatives that were not members of a power supply cooperative on January 1, 1999, and as long as they do not become members, their cost of purchased wholesale power and discounts from capped rates to match the cost of providing distribution services, and (v) with respect to cooperatives that were members of a power supply cooperative on January 1, 1999, their recovery of fuel costs, through the wholesale power cost adjustment clauses of their tariffs pursuant to § 56-231.33. Notwithstanding the provisions of § 56-249.6, the Commission may authorize tariffs that include incentives designed to encourage an incumbent electric utility to reduce its fuel costs by permitting retention of a portion of cost savings resulting from fuel cost reductions or by other methods determined by the Commission to be fair and reasonable to the utility and its customers.

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§ 56-583. Wires charges.

A. To provide the opportunity for competition and consistent with § 56-584, the Commission shall calculate wires charges for each incumbent electric utility, effective upon the commencement of customer choice, which shall be the excess, if any, of the incumbent electric utility's capped unbundled rates for generation over the projected market prices for generation, as determined by the Commission; however, where there is such excess, the sum of such wires charges, the unbundled charge for transmission and ancillary services, the applicable distribution rates established by the Commission and the above projected market prices for generation shall not exceed the capped rates established under § 56-582 A 1 applicable to such incumbent electric utility. The Commission shall adjust such wires charges not more frequently than annually and shall seek to coordinate adjustments of wires charges with any adjustments of capped rates pursuant to § 56-582. No wires charge shall be less than zero. The projected market prices for generation, when determined under this subsection, shall be adjusted for any projected cost of transmission, transmission line losses, and ancillary services subject to the jurisdiction of the Federal Energy Regulatory Commission which the incumbent electric utility (i) must incur to sell its generation and (ii) cannot otherwise recover in rates subject to state or federal jurisdiction.

B. Customers that choose suppliers of electric energy, other than the incumbent electric utility, or are subject to and receiving default service, prior to the expiration of the period for capped rates, as provided for in § 56-582, shall pay a wires charge determined pursuant to subsection A based upon actual usage of electricity distributed by the incumbent electric utility to the customer (i) during the period from the time the customer chooses a supplier of electric energy other than the incumbent electric utility or (ii) during the period from the time the customer is subject to and receives default service until capped rates expire or are terminated, as provided in § 56-582.

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§ 56-584. Stranded costs.

Just and reasonable net stranded costs, to the extent that they exceed zero value in total for the incumbent electric utility, shall be recoverable by each incumbent electric utility provided each incumbent electric utility shall only recover its just and reasonable net stranded costs through either capped rates as provided in § 56-582 or wires charges as provided in § 56-583. To the extent not preempted by federal law, the establishment by the Commission of wires charges for any distribution cooperative shall be conditioned upon such cooperative entering into binding commitments by which it will pay to any power supply cooperative of which such distribution cooperative is or was a member, as compensation for such power supply cooperative's stranded costs, all or part of the proceeds of such wires charges, as determined by the Commission.

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§ 56-590. Divestiture, functional separation and other corporate relationships.

A. The Commission shall not require any incumbent electric utility to divest itself of any generation, transmission or distribution assets pursuant to any provision of this chapter.

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§ 56-595. Legislative Transition Task Force established.

A. The Legislative Transition Task Force is hereby established to work collaboratively with the Commission in conjunction with the phase-in of retail competition within the Commonwealth.

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C. The Task Force members shall be appointed to begin service on and after July 1, 1999, and shall continue to serve until July 1, 2005. They shall . . . (iii) after the commencement of customer choice, monitor, with the assistance of the Commission, the Office of the Attorney General, incumbent electric utilities, suppliers, and retail customers, whether the recovery of stranded costs, as provided in § 56-584, has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs; . . .and v) annually report to the Governor and each session of the General Assembly during their tenure concerning the progress of each stage of the phase-in of retail competition, offering such recommendations as may be appropriate for legislative and administrative consideration in order to maintain the Commonwealth's position as a low-cost electricity market and ensuring that residential customers and small business customers benefit from competition.

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§ 56-596. Advancing competition.

A. In all relevant proceedings pursuant to this Act, the Commission shall take into consideration, among other things, the goals of advancement of competition and economic development in the Commonwealth.

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Virginia Stranded Cost Proceeding
Case No. PUE-2003-00062
Answers to SCC Questions Contained in its March 3, 2003 Order

Question No. 7

Provide copies of any study or studies undertaken to define and/or calculate stranded costs for any Virginia electric utility.

Response

See Question No. 7, Attachment 1, for a 1997 vintage paper concerning AEP/APCo's Projected Stranded Commitments assignable to Virginia. This paper is being provided in response to this question even though it is more of a sensitivity analysis, rather than a study undertaken to define and/or calculate stranded costs.

Question No. 7, Attachment 2, lists the witnesses who filed testimony in Case No. 98-0452-E-GI, a proceeding before the Public Service Commission of West Virginia (PSC) that dealt with stranded cost issues. Copies of those witnesses' testimony is available on the PSC's website at the following addresses:

http://www.psc.state.wv.us/elecrest/19990707/default.htm (Direct Testimony)

http://www.psc.state.wv.us/elecrest/19990806/default.htm (Rebuttal Testimony)

Question No. 7
Attachment 2

Stranded Cost Testimony Filed
In Case No. 98-0452-E-GI
Before the Public Service Commission of West Virginia

Party	Witness
Appalachian Power Company/ Wheeling Power Company	John H. Landon
	Jan Umbaugh
AARP	Barbara Alexander
Allegheny Power	John Howells
	Michael Morrell
	Howard Pifer
	James Spayer
	William Avera
	David Benson
Consumer Advocate Division	Randy Allen
	Paul Chernick
	Michael J. Majoros
	Bruce Biewald
Muni Coops	Daniel M. Walker
PSC Staff	Dave Ellis
	Tom Torries
Weirton Steel	David Johnstone
	Michael Gorman
West Virginia Power	Steve Jurek
WVEUG	Randall J. Falkenberg
	Stephen J. Baron
	Lane Kollen
WV Retail Association	James Clarkson

Virginia Stranded Cost Proceeding
Case No. PUE-2003-00062
Answers to SCC Questions Contained in its March 3, 2003 Order

Question No. 8

Provide any additional comments on the issues raised by Requested Actions paragraphs 2 and 3 of the LTTF Resolution.

Response

APCo appreciates the opportunity to provide its initial comments on the issues raised by the LTTF's Resolution and looks forward to participating in the upcoming work group. Once the work group meets and has a chance to review and discuss various comments regarding Requested Actions paragraph 2 of the LTTF's Resolution, including those of the Company, the workgroup will be in a position to discuss any necessary response to Requested Actions paragraph 3 of that Resolution.

American Electric Power
PO Box 2021
Roanoke, VA 24022-2121
540 985-2300

AMERICAN ELECTRIC POWER

July 30, 1997

Mr. William F. Stephens, Director
Division of Energy Regulation
State Corporation Commission
P. O. Box 1197
Richmond, VA 23209

R. Daniel Carson, Jr.
Virginia President
540 985 2900

Dear Bill:

During one of the meetings of the Stranded Cost Working Group, Virginia Power Company representatives presented an analysis ~~which supported their~~ Company's estimate of the net plant investment which could be expected to be rendered uneconomic in a competitive environment. You subsequently asked during the meeting if AEP had performed a similar analysis or if it would perform such an analysis.

In this regard, I am enclosing for your review a recently completed paper concerning AEP's/APCO's Projected Stranded Commitments assignable to Virginia. Rich Munczinski had the primary responsibility for preparing this analysis, and he and I would welcome the opportunity to meet with you to discuss it at your earliest convenience.

Sincerely,

R. Daniel Carson, Jr.

dml

Enclosure

Copy: Mr. R. E. Munczinski (w/o enclosure)
Mr. B. L. Thomas (w/enclosure)
Mr. M. S. Lawrence (w/enclosure)

Appalachian Power Company d/b/a/ American Electric Power
Projected Stranded Commitments - Virginia

As part of its ongoing efforts regarding restructuring and competition in the electric utility industry, Appalachian Power Company, d/b/a/ American Electric Power (APCo or the Company), has endeavored to quantify its projected stranded commitments. The term "stranded commitments" refers to (1) net stranded costs for generation assets, and (2) generation-related regulatory assets.

The Company's quantification of projected stranded commitments was conducted in two parts: Generation-related net stranded costs were first quantified by subtracting the present value of future cash flows associated with generating assets from the net investment (net book value) of the generation assets as of December 31, 1996, and then allocated to the Virginia retail jurisdiction. Regulatory assets were taken from the books of account as of that date, and allocated or specifically assigned to the Virginia retail jurisdiction.

While the determination of generation-related regulatory assets is relatively straight forward, projecting a utility's generation-related net stranded costs is a difficult matter that is dependent upon a myriad of variables. Changing assumptions about any of these variables will likely lead to widely differing results. In addition, the industry debate on stranded cost calculations is in its infancy. The assumptions and variables underlying the projections contained herein are based upon the best available information at this time and AEP reserves the right to advance the use of other assumptions, variables and methodologies at some future date.

Given that the AEP System was developed and is operated as a single, integrated and coordinated unit to serve the combined load of all customers within the service areas of its operating utility companies, it is appropriate to evaluate any projected generation-related stranded costs on an AEP System basis. In order to minimize controversy, we have also quantified this information for APCo on a stand-alone basis.

Attachment 1, consisting of one page, is a summary of projected generation-related net stranded costs for the AEP System, for APCo's Virginia retail jurisdictional share of the AEP System, and for APCo (both total company and Virginia retail jurisdiction) on a stand-alone basis including the capacity settlement under the AEP Interconnection Agreement. The calculations were performed assuming levelized market prices of 2.50 ¢/kWh, 2.75 ¢/kWh and 3.00 ¢/kWh over the 20-year study period. Also shown on this page are the results of a further sensitivity analysis that depicts the effect on projected generation-related net stranded costs assuming each generating asset's capacity factor is increased by 5 percentage points throughout the study period. Attachment 2, consisting of two pages, is a description of the major assumptions used to project generation-related net stranded costs.

A quantification of APCo's generation-related regulatory assets, as of December 31, 1996, was previously filed with the Virginia State Corporation Commission, in Case No. PUE960301, as part of APCo's request for approval of an alternative regulatory plan and for a general increase in electric rates. For convenience, a copy of that quantification is enclosed as Attachment 3.

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Appalachian Power Company d/b/a American Electric Power
Virginia Retail Jurisdiction
Projected Generation Related Net Stranded Costs

	Net Book Value	Projected Generation Related Net Stranded Costs at: 2.5 cents	2.75 cents	3 cents
AEP System	$4,686.7 M	$3,938.9 M (84%)	$1,966.7 M (42%)	$(5.4) M
APCo -VA Retail (Rate Case Allocators)		$527.8 M	$263.5 M	$(0.7) M
AEP System w/ Incr Cap Fact	$4,686.7 M	$3,397.3 M (72%)	$1,280.0 M (27%)	$(837.3) M
APCo -VA Retail (Rate Case Allocators)		$455.2 M	$171.5 M	$(112.2) M
APCo (with Capacity settlement)	$885.1 M	$885.1 M (entire)	$680.8 M	$240.2 M
APCo -VA Retail (Rate Case Allocators)		$394.8 M	$303.6 M	$107.1 M
APCo with Incr Cap Factor	$885.1 M	$885.1 M (entire)	$512.5 M	$36.7 M
APCo -VA Retail (Rate Case Allocators)		$394.8 M	$228.6 M	$16.4 M

ATTACHMENT 1

Major Assumptions for Projected Generation-Related
Net Stranded Costs Quantification

1. Generation from the AEP System's generating plants was assumed to escalate at 1.3% per year through the year 2008 and then decline at a constant rate of 1.6% per year through 2015 to reflect retirement of units. For APCo, generation was assumed to escalate at 2.5% per year through the year 2010 and then decline at a constant rate of 3.2% through the year 2015 to reflect retirement of APCo generating units.

2. Total Revenue projections were calculated for AEP and APCo generating plants using levelized market prices of 2.5 cents per kWh, 2.75 cents per kWh and 3.00 cents per kWh.

3. Fuel costs for the AEP System's generating plants were assumed to increase at 3.1% per year through 2008, which reflects load growth and cost escalation. Thereafter, fuel costs were assumed to increase at 0.5% per year through 2015 which reflects cost escalation and a decline in generation.

4. Fuel costs for APCo's generating plants were assumed to increase at 3.5% per year through 2010 which reflects load growth and cost escalation. Thereafter, fuel costs were assumed to increase at 0.7% per year through 2015, which reflects cost escalation and a decline in generation.

5. Other O&M expenses, Depreciation and Taxes Other Than Income Taxes were based on Corporate Planning and Budgeting projections for the years 1996 through 2015 and/or were specifically calculated for those years using composite depreciation or revenue tax rates. Projected amounts only reflect generation-related expenses for these items of expense.

6. APCo's projected stranded cost calculations include AEP System Pool capacity equalization payments of $127 million per year escalated at 1% per year through 2015.

7. Current Federal/State income taxes were calculated for the AEP System and APCo based on the study's projections of pre-tax book income from the generation assets and estimates of Schedule M tax adjustments. A composite federal/state income tax rate of 37% was used for AEP and 38.05% for APCo. Deferred federal income taxes and deferred investment tax credits were calculated based on the tax normalization treatment of timing differences for the AEP System and APCo.

8. Net Investment (net book value) includes production plant, generation-related transmission and general plant, fuel inventory, a portion of materials & supplies inventory and prepayments less accumulated deferred federal income taxes, based on projections obtained from Corporate Planning & Budgeting for the years 1996-2015.

9. A net-of-tax discount rate of 8.9% (13.69% on a before-tax-basis) was used to discount future cash flows for AEP's and APCo's generating assets back to December 31, 1996. The sum of the present value of future cash flows as of December 31, 1996 was subtracted from the net book value of the generation assets as of that date to obtain the quantification of generation-related net stranded cost, if any.

10. The capacity factors for the AEP System's and APCo's generating plants were increased by 5 percentage points to determine the sensitivity that an increase in capacity utilization would have on projected stranded costs. For the AEP System, the capacity factor was increased from a projected 20-year average of approximately 69% to approximately 74%, while for APCo's generating plants, the capacity factor was increased from approximately 65% to approximately 70%.

[H:\mjl\apco\attach2.w51]

Allegheny Power

LEGAL DEPARTMENT

10435 Downsville Pike
Hagerstown, MD 21740-1766
(301) 790-3400

Writer's Direct line: 301-790-6283
FAX: 301-790-6460

March 20, 2003

VIA OVERNIGHT MAIL
Ronald A. Gibson, Director
Division of Public Utility Accounting
State Corporation Commission
Tyler Building, 4th Floor
1300 E. Main Street
Richmond, VA 23219

Re: In the Matter of Developing Consensus Recommendations On Stranded Costs - VA SCC Case No. PUE-2003-00062

Dear Mr. Gibson:

By order dated March 3, 2003 in this case, the Commission requested responses to eight questions concerning stranded costs. Enclosed please find responses on behalf of The Potomac Edison Company d/b/a Allegheny Power. As requested by the Commission's order, an electronic copy of this document is also being forwarded to econfin@scc.state.va.us.

We appreciate your kind attention to this matter.

Very truly yours,

Philip J. Bray

Philip J. Bray
Attorney

Enclosure

cc: Lawrence T. Oliver, Assistant Director, Division of Economics & Finance
William F. Stephens, Director, Division of Energy Regulation
Wayne N. Smith, Office of General Counsel

Before the

State Corporation Commission

of Virginia

In the matter of developing consensus recommendations on stranded costs	* * *	Case No. PUE- 2003-00062

Comments by Allegheny Power

On March 3, 2003 the Commission issued an order initiating this proceeding for the purpose of developing consensus recommendations on stranded costs. In its order, the Commission posed several questions for input on this important and very complex subject.

Allegheny Power would like to preface its comments by stating that its situation with regard to stranded costs is significantly different than several of the other incumbent electric utilities in Virginia. AP legally transferred its generation assets to its affiliate, Allegheny Energy Supply Company, LLC on August 1, 2000 as part of its functional separation plan in Case No. PUE-2000-00280. In addition, as part of a Memorandum of Understanding ("MOU") with the Commission Staff in that case, AP waived its right to assess a wires charge and instead pledged to recover stranded costs solely through capped rates.

Although AP does not have a wires charge, the Company has monitored the Commission's activity in establishing wires charges in Case No. PUE-2001-00360. AP finds the Commission's approved methodology for calculating and annually establishing the wires charge as an effective means to recover stranded costs resulting from an incumbent's customers switching to an alternative supplier. The Commission establishes the projected market price for generation annually using forward-looking pricing data, providing a value that is representative of the price for which the incumbent's displaced power would be sold in the market.

Clearly the Restructuring Act's intent in establishing the wires charge in § 56-583 was for the incumbent to be "made whole" in the event any of its customers switched to an alternative supplier during the rate cap period. The Restructuring Act is a carefully crafted document, reflecting the study, compromise, and negotiation of many parties. The Restructuring Act does not provide a mechanism for quantifying total stranded costs for each utility, and AP questions the need to do so now. This is a value that can change significantly over the course of the capped rate period, given varying market conditions and other economic factors. To expend effort at this point attempting to quantify total stranded costs for each utility is of questionable practical value.

In light of these facts, AP offers the following general comments in response to the questions set forth in the Commission's order dated March 3, 2003. AP looks forward to working with the stranded cost work group in developing recommendations on these very important questions.

Question 1: Define "stranded costs." Include in the definition a detailed listing of each stranded costs component. Is this definition applicable to all electric utilities operating in Virginia? If not, to which utility or utilities does it apply and why?

Stranded costs are those costs that would have been recovered under regulation that cannot be recovered in a deregulated environment. Stranded costs include the following major components:

Losses in the economic value of an incumbent's investments and obligations related to electric generation supply that resulted from deregulation - Under traditional utility ratemaking the costs prudently incurred by utilities and a reasonable return on investment would be recovered in regulated rates. In a deregulated environment the market cost of generation may be different than the regulated rate. If the market rate is lower than the regulated rate and the utility loses sales, the costs not recovered through the lost revenues would be a stranded cost (lost revenues consisting of expenses, investment and return not recovered by the utility). Under capped rates, a higher market rate than the regulated capped rate offers no benefit to the utility.

Devaluation in Generation Assets - If the utility decided to sell generation assets because it could not offer the lower rates dictated by the marketplace it is likely that the sale price of the generation plant may be less than the book value of the plant. Since the low sales price is not likely to cover the book value of the plant and the ratepayers would no longer be paying for the carrying costs and depreciation of the plant in rates, the difference between the book value and the sales price would be a stranded cost.

Transition Costs - Costs that would not have been incurred by the utility but for the adoption of restructuring legislation may also be labeled as stranded costs. Examples of potential restructuring costs not recovered through existing rates are consumer education costs, modifications of billing systems to accommodate new billing procedures, expanded customer service facilities, revisions to metering processes necessitated by customer choice, and costs of joining or establishing an RTO.

Deferred Costs and Regulatory Assets - If the utility has deferred costs or other deferred liabilities that will not be collected under a restructured environment then these costs that have been paid for but not yet collected would be a stranded cost.

In summary, any Virginia electric utility that experiences any of the conditions stated above will be deemed to have stranded costs.

Question 2: Define "just and reasonable net stranded costs." Provide a detailed explanation of how and why it differs from "stranded costs." Is this definition applicable to all electric utilities operating in Virginia? If not, to which utility or utilities does it apply and why?

AP perceives these to be essentially the same as the costs discussed in its response to question 1, with the slight distinction that these are *net losses* associated with retail competition. Just and reasonable net stranded costs are the net costs or losses that would have been recoverable under regulation that cannot be recovered under deregulation.

Question 3: Provide a methodology for calculating "just and reasonable net stranded costs." Be specific in providing the necessary steps, beginning with each component comprising gross stranded costs and each component offsetting this amount to reach a net amount.

AP does not have a proposed methodology to offer at this time, but the Company recognizes this would be a complex calculation including detailed projected expenditures and market prices over a set period of time.

Question 4: Describe how stranded costs are recovered. Provide a methodology for calculating such recovery. Describe the recovery period.

§ 56-584 of the Restructuring Act provides for just and reasonable net stranded costs to be recovered through either capped rates as provided in § 56-582 or wires charges as provided in § 56-583.

As mentioned earlier, AP waived its right to a wires charge and consequently only recovers stranded costs through capped rates during the capped rate period. The capped rate period can extend as long as July 1, 2007.

Question 5: Do the calculation and recovery methodologies described in responses to questions 3 and 4 produce (or are they likely to produce) over-recovery or under-recovery of just and reasonable net stranded costs? How should such over- or under- recovery be dealt with?

AP did not perform a calculation such as the one suggested by question number 3. However, AP notes if the recovery method is limited to the mechanisms provided for in § 56-584 of the Restructuring Act, the incumbent recovers the excess between its capped generation rate and the projected market rate, which is representative of the value it could obtain for the displaced energy in the market. The wires charge is not applicable unless the utility's customers switch to an alternative supplier. Whether or not the wires charge is invoked, the end result is the incumbent recovering its capped generation rate, which is a cost-based rate reflective of the incumbent's last base rate case.

Question 6: Requested Actions paragraph 1 of the LTTF resolution requests that the work group develop consensus recommendations "consistent with the provisions of the Act." Explain how that phrase guides or possibly constrains the actions of the work group. Identify each section of the Act, §§ 56-576 to -596 of the Code of Virginia, pertinent to such guidance or constraint. Additionally, explain each such section's significance in the context of definitions offered in response to questions 1 and 2 as well as in the methodologies proffered for calculating and recovering just and reasonable net stranded costs in response to questions 3 and 4.

AP points to § 56-584 of the Restructuring Act, which provides for just and reasonable net stranded costs to be recovered through either capped rates as provided in § 56-582 or wires charges as provided in § 56-583. These sections provide the greatest guidance on the intent of the Act with regard to this matter.

Question 7: Provide copies of any study or studies undertaken to define and/or calculate stranded costs for any Virginia electric utility.

AP has not performed any such studies for its Virginia jurisdiction. AP would like to note that in the case of its other jurisdictions, it has been the Company's experience that the stranded cost amount for utilities frequently is determined as a result of negotiation and settlement.

Question 8: Provide any additional comments on the issues raised by Requested Actions paragraphs 2 and 3 of the LTTF Resolution.

AP would simply like to reiterate that its position is significantly different than that of the other incumbent electric utilities in Virginia, in that AP has transferred its generation assets to its affiliate Allegheny Energy Supply. Also, AP waived its right to assess a wires charge in the MOU executed with Staff in its functional separation case. This MOU was designed as a comprehensive settlement to address all issues including stranded cost recovery.

In addition, AP perceives the Restructuring Act's provisions for the wires charges to adequately address the recovery of stranded costs.

In closing, AP appreciates the opportunity to offer its views on this subject matter. The Company looks forward to working with Staff and other interested parties to develop consensus recommendations on this very important issue.

March 21, 2003

In the Matter of Developing
Consensus Recommendations on
Stranded Costs

CASE NO. PUE-2003-00062

Responses of Virginia Independent Power Producers, Inc.

1. **Define "stranded costs." Include in the definition a detailed listing of each stranded cost component. Is this definition applicable to all electric utilities operating in Virginia? If not, to which utility or utilities does it apply and why?**

The term "stranded costs" is generally defined as the difference between the depreciated book value of a utility's generation assets and its market value in a fully competitive, effective marketplace.

The major components of stranded costs are utility investments that may not be fully recoverable in a competitive marketplace, such as (i) utility-owned generating assets, (ii) utility obligations regarding wholesale power purchase agreements and (iii) generation-related "regulatory assets," obligations made under a regulatory system that extended cost recovery into future periods.

The above definition is applicable to all incumbent utilities in Virginia.

2. **Define "just and reasonable net stranded costs." Provide a detailed explanation of how and why it differs from "stranded costs." Is this definition applicable to all electric utilities operating in Virginia? If not, to which utility or utilities does it apply and why.**

The term "just and reasonable net stranded costs" means the arithmetic sum of the various stranded cost components detailed in the answer to question No. 1. Further, stranded costs are "just and reasonable" if they were incurred by a utility acting prudently and in good faith, in accordance with the obligation to serve all customers known as "the regulatory compact."

3. Provide a methodology for calculating "just and reasonable net stranded costs." Be specific in providing the necessary steps, beginning with each component comprising gross stranded costs and each component offsetting this amount to reach a net amount.

With respect to customers who have switched suppliers, stranded costs can be calculated by comparing the unbundled generation component with prevailing market prices, as is done annually when computing the wires charge. This annual number can be netted over time by summing the results of each year's calculation.

This method, which considers the amount of revenue displaced by customers purchasing from competitive suppliers, measures the actual economic impact of competition on an incumbent utility. As such, the method focuses on discernable facts and information, not future projections. As the Staff of the State Corporation Commission has previously stated, reliance on projections or future estimates, not factual information, may result in errors.[1]

4. Describe how stranded costs are recovered. Provide a methodology for calculating such recovery. Describe the recovery period.

In Virginia, in accordance with Sec. 56-584 of the Virginia Electric Utility Restructuring Act, just and reasonable net stranded costs are recoverable through either capped rates as provided in Sec. 56-582 or wires charges as provided in Sec. 56-583.

The recovery period is as provided in the Restructuring Act.

5. Do the calculation and recovery methodologies described in responses to questions 3 and 4 produce (or are they likely to produce) over-recovery or under-recovery of just and reasonable net stranded costs? How should such over- or under-recovery be dealt with?

The calculation and recovery methods contained in the Virginia Electric Utility Restructuring Act will not produce over-recovery or under-recovery of just and reasonable net stranded costs. The Restructuring Act's provisions determine the extent of permitted recovery, as agreed to by stakeholders during extensive legislative debate and as ratified and approved by the Virginia General Assembly and the Governor of Virginia.

[1] "Staff is especially concerned that current estimates of long-term market prices may be biased to the downside, thereby resulting in overestimation of stranded costs for underestimation of stranded margins." Excerpt from SCC's "Draft Working Model for Restructuring the Electric Utility Industry in Virginia," November 1977

Any alleged over-recovery or under-recovery claimed should not be "dealt with" absent specific statutory authority to do so. In the absence of such statutory authority, it is inappropriate to speculate about methods to be used.

6. **Requested Actions paragraph 1 of the LTTF Resolution requests that the work group develop consensus recommendations "consistent with the provisions of the Act." Explain how that phrase guides or possible constrains the actions of the work group. Identify each section of the Virginia Electric Utility Restructuring Act, §§ 56-576 to –596 of the Code of Virginia, pertinent to such guidance or constraint. Additionally, explain each such section's significance in the context of definitions offered in response to questions 1 and 2 as well as in the methodologies proffered for calculating and recovering just and reasonable net stranded costs in response to questions 3 and 4.**

The phrase "consistent with the provisions of the Act" contained in the LTTF resolution guides the efforts of the work group and constrains its actions and recommendations by limiting the scope of the inquiry and the range of possible recommendations to those specifically and directly contemplated and permitted by the Restructuring Act. Simply stated, "consistent with the provisions of the Act" means that the work group has been granted only limited authority and should confine its recommendations to actions consistent with the provisions of the Restructuring Act.

7. **Provide copies of any study or studies undertaken to define and/or calculate stranded costs for any Virginia electric utility.**

VIPP does not possess any such studies.

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sc0320a

Commonwealth of Virginia
STATE CORPORATION COMMISSION

COMMONWEALTH OF VIRGINIA, ex rel.

STATE CORPORATION COMMISSION **SCC Case No. PUE-2003-00062**

In the Matter of Developing
Consensus Recommendations on
Stranded Costs

DIVISION OF CONSUMER COUNSEL
OFFICE OF THE ATTORNEY GENERAL
RESPONSES TO QUESTIONS
SET OUT IN ORDER OF MARCH 3, 2003

The Division of Consumer Counsel, Office of the Attorney General ("Consumer Counsel") submits these responses to the questions set out in the Commission's Order Establishing Proceeding of March 3, 2003. Consumer Counsel appreciates the opportunity to participate in the Work Group convened by the Commission to develop consensus recommendations to the General Assembly's Legislative Transition Task Force ("LTTF") addressing the definition of stranded costs, the proper method of quantifying potential stranded costs, and the status of recovery of stranded costs to date by Virginia's electric utilities.

While it will no doubt be very challenging to develop consensus on the issues of potential stranded cost quantification and recovery through the Work Group process due to the extremely large financial impact of these issues, Consumer Counsel looks forward to participating in this debate and offers the following initial comments in response to the questions posed by the Commission in its March 3, 2003 Order.

1. Define "stranded costs." Include in the definition a detailed listing of each stranded cost component. Is this definition applicable to all electric utilities operating in Virginia? If no, to which utility or utilities does it apply and why?

Stranded costs are a utility's lost revenues arising from prudently incurred, verifiable and non-mitigable electric generation-related costs that become unrecoverable due to restructuring and retail competition. The specific components of stranded costs may include unrecoverable generation capital and operating costs including fuel, purchased power costs, and regulatory assets and liabilities, such as accumulated deferred income taxes. While the above definition could technically apply to electric utilities in Virginia whose customers have retail choice, there is no evidence that Virginia's utilities have experienced any material stranded costs to date, given the very limited level of customer switching and the regulatory protection against stranded costs afforded by capped rates and wires charges as provided under the Restructuring Act. In our view, stranded costs only occur after retail electricity charges are deregulated and customers actually switch from the incumbent utility to a competitive supplier.

In order for there to be a potential for stranded costs to occur in Virginia, several changes in current market conditions must occur:

a) Retail market prices for energy must be significantly less than the regulated retail rates charged by the incumbent utility. If the "price to compare" is at a level near or below prevailing wholesale market prices, as presently is the case in Virginia, no competitors will enter the market, all retail customers will continue purchasing from the incumbent at regulated capped rates, and no costs will actually be stranded.

b) Customers must actually switch to competitive suppliers. In other jurisdictions that have implemented retail choice, switching by residential and small commercial customers has been minimal, even when the incumbent's rates are significantly higher than prevailing market prices. For example, in Texas, regulators have adopted rules that allow incumbent retail providers to charge "price to beat" rates that are well in excess of their regulated cost, with the intent of inducing residential customers to switch providers. However, even with the price to beat at levels well in excess of market prices and rates offered by competing retailers, the percentage of residential customers switching to competitive suppliers has been very small. This lack of switching exists presently in Virginia.

c) Generally, the market must be relatively stable. In many deregulated markets, highly volatile wholesale prices have resulted in bankruptcy of competitive retailers, thereby leaving their customers being served by the incumbent utility or default service provider at rates that are generally higher than prevailing market prices or traditional regulated rates. Incumbent utilities are generally better able to manage such market volatility, since they tend to have large customer bases and cash flow, whereas smaller competitive suppliers often do not have the financial resources to weather relatively minor market disturbances. When market volatility forces competitors out of the market, competition decreases (leading to higher prices) and customers are less likely to participate in retail choice. It appears that volatility in market prices and uncertainty regarding the physical infrastructure required to support retail access in Virginia have to date prevented the development of the level of market stability necessary to facilitate competition.

d) The incumbent utility must have limited opportunities to mitigate losses caused by customer switching and retail competition. Most incumbent generators in Virginia have relatively low embedded generation costs and therefore have many opportunities to profitably sell their energy and ancillary services into regional wholesale energy markets, thereby mitigating the impact of any customer load loss due to retail competition. As long as Virginia's utilities have such mitigation opportunities stranded costs are unlikely to be experienced.

2. Define "just and reasonable net stranded costs." Provide a detailed explanation of how and why it differs from "stranded costs." Is this definition applicable to all electric utilities operating in Virginia? If not, to which utility or utilities does it apply and why?

Consumer Counsel's definition for "stranded costs" as provided in response to Question No. 1 also applies to the term "just and reasonable net stranded costs" as used in § 56-584 of the Restructuring Act. The "just and reasonable net" modifiers should be inherently reflected in any definition of stranded costs and are specifically addressed in the "prudent, verifiable and non-mitigable" standards set forth in Consumer Counsel's proposed stranded cost definition. The objective in setting these standards is to ensure that the incumbent utility is held responsible for verifying and minimizing stranded costs -- just as it has traditionally been required to demonstrate the prudence of costs recovered in rates under regulated ratemaking -- and to ensure that consumers are responsible for any such legitimate stranded costs which are found to have been incurred.

3. Provide a methodology for calculating "just and reasonable net stranded costs." Be specific in providing the necessary steps, beginning with each component comprising gross stranded costs and each component offsetting this amount to reach a net amount.

As explained in Consumer Counsel's response to Question No. 1, stranded costs currently do not exist in Virginia due to the lack of retail competition and customer switching to date. However, there are two major approaches for quantifying potential stranded costs: "Administrative Methods" and "Market-based Methods." Under both approaches, potential stranded costs are calculated as the difference between the regulated net book value and the market value of generating assets and purchased power resources. It generally is difficult to quantify potential stranded costs with great precision due to the fact that the market value of generating assets is measured as the present value of the difference between the operating costs of such assets and the revenues they can produce from sales of capacity and energy over their remaining operating lives. In many cases, the level of electric operating costs and revenues for generating assets is difficult to predict, particularly over the long operating lives of such facilities.

In particular, this is a problem for natural gas-fired generating facilities, since the price of gas has been highly volatile in recent years. This inherent uncertainty in the potential stranded cost quantification process is somewhat reduced by using "market-based" stranded cost quantification methods, such as comparable sales or actual divestiture of the generating assets at question. However, even these market-based methods may not accurately reflect the true market value of a generating asset (and thus its stranded costs) due to market volatility. For example, a sale of generating assets under current depressed energy market conditions may not reflect the full market value of such facilities if sold at a later date when market conditions are more favorable. Furthermore, it is difficult to obtain information on "comparable sales" of generating assets since the details of such transactions are often confidential. In any event, the divestiture option does not appear to be a viable method for the Work Group's determination of stranded costs for the purposes established by the LTTF.

With due consideration of the problems noted above with both administrative and market-based methods of quantifying potential stranded costs, Consumer Counsel recommends that the Commission consider using both methods, with multiple scenarios considered to address the range of uncertainty in underlying assumptions and resultant potential stranded costs. Under each method, potential stranded costs will be determined by taking the difference between the market value and regulated book value of the assets.

For the administrative method, this would be achieved through a lost revenues calculation that computes the present value of the difference between the capital and operating costs of such assets and the projected revenues earned from energy sold from such assets under capped rates or at market-based rates including wires charges, under scenarios that reflect a reasonable level of customer switching and range of market prices.

For the market-based method, potential stranded costs would be calculated as the difference between the regulated net book value of the assets and the market value as indicated by comparable plant sales, to the extent the Work Group can obtain an adequate sample of comparable sales information for such an analysis.

4. Describe how stranded costs are recovered. Provide a methodology for calculating such recovery. Describe the recovery period.

As set forth in § 56-584 of the Restructuring Act, just and reasonable net stranded costs, to the extent they exceed zero in value, shall be recovered through capped rates or wires charges, which are effective during the capped rate period (January 1, 2001 through July 1, 2007). The methods for establishing such charges have already been addressed by the Commission. In the event that the Work Group's quantification of potential stranded costs indicates that a utility is likely to over-recover or under-recover its stranded costs, recommendations for adjustment to the capped rates and/or wires charge calculation could be considered to eliminate the estimated over- or under-recoveries over the remaining term of the capped rate period. Generally, any adjustments to capped rates and/or wires charge calculations should be made in a manner that is consistent with the cost allocation and rate design methods that were applied in the design of the original capped rates and wires charges.

5. Do the calculation and recovery methodologies described in responses to questions 3 and 4 produce (or are they likely to produce) over-recovery or under-recovery of just and reasonable net stranded costs? How should such over- or under-recovery be dealt with?

As described in Consumer Counsel's response to Question No. 3, Virginia's electric utilities presently do not have stranded costs and are not likely to have stranded costs in the foreseeable future until retail competition exists and other changes in current market conditions have occurred. While even the most common and widely-accepted methods of quantifying potential stranded costs are not likely to produce precise forecasts of potential stranded costs, if reasonably applied such calculation methods, and any resultant recovery methods applied to adjust for the results of such calculations, should not necessarily produce either over- or under-recoveries of stranded costs. However, even with the best of intentions, at the end of the capped rate period it is likely that some level of over- or under-recovery of stranded costs will exist depending on the value assigned to potential stranded cost exposure after the capped rate period. Any over- or under-recovery that is determined to exist through the LTTF's efforts could be addressed through adjustments in the capped rates and/or wires charges. Any adjustment to capped rates would likely need to consider the cost of service of each incumbent utility.

6. **Requested Actions paragraph 1 of the LTTF Resolution requests that the work group develop consensus recommendations "consistent with the provisions of the Act." Explain how that phrase guides or possibly constrains the actions of the work group. Identify each section of the Virginia Electric Utility Restructuring Act, §§ 56-576 to -596 of the Code of Virginia, pertinent to such guidance or constraint. Additionally, explain each such section's significance in the context of definitions offered in response to questions 1 and 2 as well as in the methodologies proffered for calculating and recovering just and reasonable net stranded costs in response to questions 3 and 4.**

The referenced passage from paragraph 1 of the LTTF Resolution guides the Work Group's effort in two respects. First, the passage references § 56-584 of the Restructuring Act which provides that only just and reasonable net stranded costs -- to the extent they exceed zero in value -- shall be recoverable through capped rates or wires charges. The capped rates and wires charges are in effect from January 1, 2001 through July 1, 2007. This section of the Act indicates that to the extent a utility realizes stranded costs they must be absorbed through its capped rates or wires charges. The referenced § 56-595 of the Act, further emphasizes that the LTTF's role in monitoring stranded costs is to ensure that a utility's capped rates or wires charges are set in a manner such that they do not result in the over- or under-recovery of just and reasonable net stranded costs. When taken together these passages focus the current Work Group effort on two tasks: 1) reasonably estimating each utility's potential stranded costs and, 2) determining whether the existing methodology for recovery is appropriate.

7. **Provide copies of any study or studies undertaken to define and/or calculate stranded costs for any Virginia electric utility.**

Consumer Counsel has not undertaken any such analysis to date.

8. **Provide any additional comments on the issues raised by Requested Actions paragraphs 2 and 3 of the LTTF Resolution.**

Consumer Counsel welcomes this opportunity to participate with the Work Group in addressing the definition of stranded costs, the proper method of quantifying potential stranded costs, and the present status of and forecasts for the recovery of stranded costs by incumbent utilities. In addition to these efforts, there will ultimately need to be a determination as to the appropriate use of the information developed by the Work Group.

Respectfully submitted,

DIVISION OF CONSUMER COUNSEL

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March 21, 2002

CERTIFICATE OF SERVICE

I hereby certify that true copies of the foregoing "Response to Questions" of the Division of Consumer Counsel, Office of the Attorney General, were hand delivered or mailed, first class, postage prepaid, this 21st day of March, 2003, to: Ronald A. Gibson, Director, Division of Public Utility Accounting, State Corporation Commission, P.O. Box 1197, Richmond, Virginia 23218-1197; Lawrence T. Oliver, Assistant Director, Division of Economics and Finance, State Corporation Commission, P.O. Box 1197, Richmond, Virginia 23218-1197; William F. Stephens, Director, Division of Energy Regulation, State Corporation Commission, P.O. Box 1197, Richmond, Virginia 23218-1197; Wayne, N. Smith, Office of General Counsel, State Corporation Commission, P.O. Box 1197, Richmond, Virginia 23218-1197; and an electronic version transmitted to econfin@scc.state.va.us.

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March 21, 2003

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Re: ***Commonwealth of Virginia, ex.rel. State Corporation Commission***
In the matter of developing consensus recommendations on stranded costs
Case No. PUE-2003-00062

Gentlemen:

In accordance with the Commission's *Order Establishing Proceeding*, dated March 3, 2003, in the above matter ("Order"), I am submitting the Comments of the Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates ("Comments").

The Comments, at page 6, reference two documents as attachments. Both documents are "redacted" versions of testimony and exhibits. Neither contains information alleged to be confidential and proprietary. Pursuant to the Order, the Committees will await the development of procedures by the Commission's Office of General Counsel prior to any disclosure of "un-redacted" versions of the two documents.

Thank you for your assistance. Please contact me if you have any questions concerning this submittal.

Very truly yours,

Edward L. Petrini

cc: State Corporation Commission
Division of Economics and Finance
(econfin@scc.state.va.us)

#631386

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

COMMONWEALTH OF VIRGINIA, ex rel.
STATE CORPORATION COMMISSION
In the Matter of Developing
Recommendations on
Stranded Costs

Case No. PUE-2003-00062

COMMENTS OF THE VIRGINIA COMMITTEE FOR FAIR UTILITY RATES AND THE OLD DOMINION COMMITTEE FOR FAIR UTILITY RATES

The Virginia Committee For Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates (collectively, "the Committees"), by counsel, submit these comments in response to the questions posed by the Commission in its Order Establishing Proceeding, dated March 3, 2003. The Committees appreciate the opportunity to comment and look forward to participating in the work group established by that order.

Respectfully submitted,

VIRGINIA COMMITTEE FOR
FAIR UTILITY RATES

OLD DOMINION COMMITTEE FOR
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March 21, 2003

RESPONSES TO QUESTIONS REGARDING JUST AND REASONABLE NET STRANDED COSTS

1. *Define "stranded costs." Include in the definition a detailed listing of each stranded cost component. Is this definition applicable to all electric utilities operating in Virginia? If not, to which utility or utilities does it apply and why?*

   Stranded costs may be defined as booked, embedded generation-related costs that are not recovered or recoverable by an incumbent electric utility as a result of retail customer choice, as provided in Virginia's Electric Utility Restructuring Act ("Restructuring Act"). Stranded cost components include unrecovered and unrecoverable costs associated with each of the utility's generating units, purchased power contracts (including any non-utility generation, or "NUG," contracts), generation-related regulatory assets, and nuclear decommissioning costs (if applicable). A generating unit's stranded costs may not exceed its remaining net book value.

2. *Define "just and reasonable net stranded costs." Provide a detailed explanation of how and why it differs from "stranded costs." Is this definition applicable to all electric utilities operating in Virginia? If not, to which utility or utilities does it apply and why?*

   "Just and reasonable net stranded costs" differ from "stranded costs." "Just and reasonable net stranded costs" include only "net" stranded costs that are "just and reasonable." "Net stranded costs" refer to the positive excess, if any, of generation-related stranded costs ("gross" stranded costs) over generation-related stranded "benefits." (Stranded "benefits" represent the inverse of stranded costs – the *excess* of market value over net booked, embedded costs.) Generation-related components of such costs include those identified in response to question 1 – *i.e.*, "just and reasonable net stranded costs" associated with the incumbent electric utility's generation units, purchased power contracts (including NUG contracts), generation-related regulatory assets, and nuclear decommissioning (if applicable). "Just and reasonable" net stranded costs include net stranded costs whose recovery would be permitted under traditional ratemaking principles designed to produce "just and reasonable," cost-based rates to utility customers. Thus, recovery of such costs in rates depends upon the fairness, or "justness," and "reasonableness" of allowing their recovery in rates, including the reasonableness and prudence of the utility's incurrence of such costs. Inquiry into the reasonableness of their recovery includes consideration of the extent to which the utility reasonably could avoid, or mitigate, or could have avoided or mitigated, such costs.

3. *Provide a methodology for calculating "just and reasonable net stranded costs." Be specific in providing the necessary steps, beginning with each component comprising gross stranded costs and each component offsetting this amount to reach a net amount.*

Calculation of "just and reasonable net stranded costs" includes a market assessment of the utility's generation and its purchased power contracts. The methodology should include the development of market prices for use in determining the market value for the utility's generating units and purchased power contracts. The market values are then compared with the remaining net book value of the generating units and generation-related regulatory assets, and the net present value ("NPV") of decommissioning costs. For purchased power contracts, comparison is made between the NPV of the stream of contractual costs and the NPV of the contracts at their market value.

A "market-based" determination of the market value of generation assets and obligations utilizes prices resulting from their sale, or the sale of related securities, in arm's-length transactions. This is distinguishable from "administrative approaches," which rely instead upon computer models to produce long-term projections of market prices over the useful lives of the utility's assets and the duration of such agreements.

An auction of entitlements to regulated generation capacity into the wholesale market, such as the capacity auctions required in Texas as part of that State's restructuring law, is one market-based methodology for determining market value. If asset ownership is transferred to a separate entity that then issues stock that is traded on a national exchange, moreover, the stock price may help determine market value of the underlying asset. The stock must be on the market for a sufficient period to establish a fair market value. If the asset is encumbered or if the transfer of the asset is not accomplished in a manner that maximizes its stock price, then appropriate adjustments are required to determine market value. Thus, an encumbrance that reduces the market value of the asset must be reflected in calculating stranded costs.

"Administrative" determinations may be more subject to manipulation than market-based approaches. As indicated above, they rely on computer models to produce long-term projections of market prices and market value. Administrative determinations must measure the full value of the utility's assets over their remaining useful lives. Value may be lost if the forward assessment of market prices is improperly time limited or fails to capture the true value of infrastructure unique to utility generating assets. (Such assets are valuable due to their limited number and strategic location near fuel and water supplies and the transmission grid.)

It is also important that models used in administrative determinations dispatch generating capacity that is economic to operate. A utility would not be prudent to operate generation when it would incur a loss in doing so.

If "administrative" approaches are used to project market values, careful attention must be paid to the underlying assumptions. Models that project the market value of such long-lived assets and obligations are especially sensitive to electricity price assumptions. In any case, as indicated above, stranded costs cannot exceed the remaining net book value of generating assets.

4. *Describe how stranded costs are recovered. Provide a methodology for calculating such recovery. Describe the recovery period.*

Under the Restructuring Act, an incumbent utility's just and reasonable net stranded costs, to the extent that they exceed zero in value in total, are "recoverable," provided that the utility "shall only recover" such costs "through either capped rates as provided in § 56-582 or wires charges as provided in § 56-583." The Restructuring Act thus affords two means for the recovery of such costs – capped rates and wires charges.

A methodology for the recovery of such costs would calculate the utility's annual revenues from capped rates and wires charges and the utility's annual, jurisdictional revenue requirements through July 1, 2007. The excess of the sum of such annual revenues over the sum of such annual jurisdictional revenue requirements, and revenue from wires charges, would reflect the recovery of just and reasonable net stranded costs.

In calculating historic, annual revenue requirements, the Commission should rely upon traditional methods – *i.e.*, review of the utility's annual information filings ("AIF's"). In calculating projected annual revenue requirements, the Commission should rely upon traditional procedures for projecting the utility's jurisdictional revenue requirements.

5. *Do the calculation and recovery methodologies described in responses to questions 3 and 4 produce (or are they likely to produce) over-recovery or under-recovery of just and reasonable net stranded costs? How should such over- or under-recovery be dealt with?*

The calculation and recovery methodologies described in the responses to questions 3 and 4 are likely to produce over-recoveries of just and reasonable net stranded costs. The Restructuring Act does not specify how an over-recovery or under-recovery should be "dealt with."

One consequence of the over-recovery of such costs should be recommendations for the repeal of the Restructuring Act's provisions requiring the imposition of wires charges on customers that purchase power from alternative generation suppliers. As indicated above, the wires charges afford one of the two means of recovery of just and reasonable net stranded costs; however, if the incumbent utility's capped rates and wires charges are over-recovering such costs, any justification for the imposition of wires charges on such customers would be eliminated.

6. *Requested Actions paragraph 1 of the LTTF Resolution requests that the work group develop consensus recommendations "consistent with the provisions of the Act." Explain how that phrase guides or possibly constrains the actions of the work group. Identify each section of the Virginia Electric Utility Restructuring Act, §§ 56-576 to –596 of the Code of Virginia, pertinent to such guidance or constraint. Additionally, explain each such section's significance in the context of definitions offered in response to questions 1 and 2 as well as in the methodologies proffered for calculating and recovering just and reasonable net stranded costs in response to questions 3 and 4.*

The work group's recommendations must be consistent with the Act's requirement for consideration of -- "just and reasonable net stranded costs," as described above. *See*, Va. Code 56-584. Thus, for example, the group's recommendations should not fail to "net" the utility's stranded costs by ignoring generating assets that represent stranded "benefits."

The group's recommendations also must be "consistent with the provisions of the Act" in that they must rely upon the utility's capped rates and wires charges for determining revenues, and upon the utility's revenue requirements, as described above, in calculating the utility's over-recovery or under-recovery of just and reasonable net stranded costs.

7. *Provide copies of any study or studies undertaken to define and/or calculate stranded costs for any Virginia electric utility.*

In Case Nos. PUE9600036 and PUE960296,[1] a number of parties submitted testimony on the subject of Virginia Power's stranded costs and appropriate methodologies for calculating them. Virginia Power proposed a method for the calculation of such costs. Its method estimated stranded costs amounting to $2.466 billion.[2] Other parties suggested that Virginia

[1] *Application of Virginia Electric and Power Company 1995 Annual Informational Filing*, Case No. PUE960036; *Commonwealth of Virginia At the relation of the State corporation Commission, Ex Parte: Investigation of Electric Utility Industry Restructuring – Virginia Electric and Power Company*, Case No. PUE960296 ("PUE960296").

[2] Id., Direct Testimony of Robert E. Rigsby, Exhibit RER _(1), Transition Cost Report, at 12,

Power's estimate was far too high, and certain of them suggested that Virginia Power would experience net stranded benefits.[3]

Attached is a copy of the Direct Testimony and Exhibits of Jeffry Pollock and Kathryn E. Iverson, filed on behalf of the Virginia Committee for Fair Utility Rates in that matter ("Ms. Iverson's testimony"). Ms. Iverson's testimony showed that, by correcting certain weaknesses in the analysis that produced Virginia Power's estimate, Virginia Power's estimated stranded net benefits soared as high as $2.7 billion.[4]

Because other parties that submitted stranded cost studies in that matter are likely to participate in the instant matter, we assume that that they will re-submit such studies in the instant matter in response to the Commission's order.

8. *Provide any additional comments on the issues raised by Requested Actions paragraphs 2 and 3 of the LTTF Resolution.*

Consideration of the overrecovery or underrecovery of "just and reasonable net stranded costs" is a complex, technical undertaking of obvious significance to all interested parties, including incumbent utilities, suppliers, customers, and the public. The Committees look forward to attempting to fashion a consensus, as described in the LTTF's resolution establishing the work group. In the absence of consensus on the issues identified by the LTTF, the work group should recommend that the Commission investigate the issues identified in the resolution for each incumbent utility by following the Commission's normal rules and

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[3] *See*, PUE960296, Direct Testimony of Craig R. Roach on behalf of the Virginia Independent Power Producers, Inc., at 86 ("...Virginia Power's transition cost estimates, although highly uncertain in any event are likely to be too high ..."); Direct Testimony of Bruce R. Oliver on behalf of the Apartment and Office Building Association of Metropolitan Washington, at 29 ("Although the work is still subject to refinement and revision, a preliminary set of calculations suggests that Virginia Power could have net negative transition costs [meaning net stranded benefits] when all elements of the company's generating plants and NUG contracts are considered."); Direct Testimony of William B. Marcus on behalf of the Southern Environmental Law Center, at 3 ("It [Virginia Power] appears to have grossly overstated its exposure to stranded generation costs (*i.e*, by figures that could rise to the billions of dollars)."); and Direct Testimony of Don Scott Norwood on behalf of the Office of Attorney General, Division of Consumer Counsel, at 5 ("Virginia Power's stranded cost analysis is badly flawed... it appears likely that the Company will have stranded margins (negative stranded costs), even without the $500 million of accelerated amortization it has proposed under the [Alternative Regulatory Plan].").

[4] See, PUE960296, Ms. Iverson's testimony at 3, 25. Virginia Power later sought to withdraw its estimates, arguing, *inter alia*, that it had offered them only as "hypothetical or illustrative aggregate transition costs" in order "to establish that such costs present an issue of substantial magnitude that needs to be dealt with ... and to provide for Commission consideration of a means of calculating such costs and providing for their recovery." (*See*, Virginia Power's Motion to Simplify Proceeding, Case No. PUE960296, dated December 2, 1997, at 2). The Commission permitted the Company to withdraw its support for its estimates, but required, nonetheless, that the estimates remain in the case. PUE960296, Order on Motion to Simplify, February 13, 1998, at 5, 6.

procedures and that it make appropriate factual findings and recommendations for use by the LTTF.

#630804.4

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing was hand-delivered or mailed, first-class postage prepaid, this 21st day of March, 2003, on each of the persons named below.

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INFORMATION ALLEGED TO BE "COMMERCIALLY SENSITIVE" DELETED

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

APPLICATION OF

VIRGINIA ELECTRIC AND POWER COMPANY **CASE NO. PUE960036**

1995 Annual Informational Filing

COMMONWEALTH OF VIRGINIA

At the relation of the

STATE CORPORATION COMMISSION **CASE NO. PUE960296**

**<u>Ex Parte</u>: Investigation of
Electric Utility Industry
Restructuring -- Virginia Electric
and Power Company**

<u>Direct Testimony of Jeffry Pollock</u>

<u>INTRODUCTION</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock, 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri, 63141-2000.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy, economic and regulatory consultant and a principal in the firm of BAI (Brubaker & Associates, Inc.)

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. Since graduation in 1975, I have been engaged in a variety of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. More details are provided in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A I am testifying on behalf of the Virginia Committee for Fair Utility Rates ("VCFUR"). The VCFUR group is comprised of 19 companies that represent a broad array of industries. VCFUR members are customers of Virginia Electric and Power Company ("Virginia Power") and purchase electricity primarily on Schedule GS-4.

Q WHAT IS THE SUBJECT OF YOUR TESTIMONY?

A I shall address Virginia Power's proposed Alternative Regulatory Plan (ARP), the quantification and recovery of "transition" costs, the proposed Transition Cost Charge (TCC), the unbundling of Virginia Power's present tariffs into discrete components, interclass revenue allocation and real time pricing (RTP).

1. ALTERNATIVE REGULATORY PLAN

Q PLEASE DESCRIBE VIRGINIA POWER'S PROPOSED ALTERNATIVE REGULATORY PLAN.

A According to Virginia Power, its Alternative Regulatory Plan (ARP) is a mechanism to enable Virginia Power to reduce its costs and to prepare for competition. The proposal defines two discrete "transition" periods. As discussed later, the nature of the transition is unclear.

The first "transition" period would commence on March 1, 1997 and continue until December 31, 2002, or when retail competition is authorized in Virginia. During this almost six-year period, base rates would remain frozen at present levels. Changes in fuel costs, however, would continue to be passed through the Fuel Cost Adjustment (FCA) as presently done. Earnings would be allowed to vary within a bandwidth defined by the earned return on equity (ROE). The earned ROE would include both regulated and unregulated businesses. Earnings in excess of an 11.5% ROE and up to 13% would be used to write down approximately $500 million of claimed regulatory assets (the amount claimed by Virginia Power that would otherwise exist at the end of the rate freeze). If Virginia Power were able to mitigate other transition costs not claimed by Virginia Power as regulatory assets, then funds from this bandwidth would be used to mitigate those costs. Earnings above the upper limit of the bandwidth (13%) would be shared equally between customers and shareholders.

The next "transition" period would commence immediately after the end of the rate freeze or when retail competition is authorized in Virginia, whichever occurs sooner. This second period would last seven years. During this seven-year period, Virginia Power would implement a TCC. The purpose of the TCC, according to the Company, would be to permit the Company an opportunity to recover all remaining *transition* costs, except nuclear decommissioning costs. The nuclear decommissioning costs would continue to be recovered in a separate charge over the projected useful lives of the nuclear units, though Virginia Power proposes to accelerate their recovery in this case. To assure recovery of all transition costs, Virginia Power asks the Commission to approve the TCC in concept *in this proceeding*, or up to six years prior to the effective date of the TCC. I shall address the TCC in Part 2 of my testimony.

Q HOW DOES VIRGINIA POWER DEFINE TRANSITION COSTS?

A Virginia Power defines *transition* costs as consisting of plant investment, regulatory assets (expenditures that are authorized to be recovered over a number of years rather than when incurred), and power purchases from non-utility generation (NUG), the costs of which will not be fully recoverable in a competitive generation/bulk power market.[1]

Q HAS VIRGINIA POWER ESTIMATED THE AMOUNT OF TRANSITION COSTS?

[1] Rigsby Direct Testimony, Page 11.

A Yes. The Company estimates that it will incur total system-wide *transition* costs of up to $3.2 billion.[2] According to the Company, this is equal to $2.5 billion on a Virginia Jurisdictional basis. Of this amount, the NUG contracts would account for $2.3 billion. It should be noted that these estimates are only for illustrative purposes. VCFUR witness Iverson provides an analysis that uses more appropriate assumptions and that shows the high degree of sensitivity of the Company's estimate to key assumptions.

Q DOES VIRGINIA POWER HAVE ANY TRANSITION COSTS TODAY?

A No. Virginia Power's nuclear plants and NUG contract costs, for example, would be more accurately described as *potentially stranded* by customer choice because the investment and expenses are currently subject to regulation and are not subject to market forces. Customer choice has not been authorized in Virginia.

Q DOES VIRGINIA POWER'S ESTIMATE OF TRANSITION COSTS MAKE ANY DISTINCTION BETWEEN COSTS THAT MAY NOT BE RECOVERABLE SOLELY DUE TO CUSTOMER CHOICE AND OTHER COSTS THAT MAY BE UNRECOVERABLE FOR REASONS UNRELATED TO COMPETITION?

A No. Virginia Power experiences diminished revenues and returns for a variety of reasons unrelated to customer choice, such as mild weather, economic down-turns, demand-side management and energy conservation measures, plant closings,

[2] Transition Cost Report, Page 12.

relocations, competition with natural gas, self-generation, and various special rates for cogeneration deferral, economic development and load retention. Because Virginia Power currently faces these risks, and because the current regulatory and legal environment currently compensates Virginia Power for these risks, these risks are unrelated to the impact of retail competition.

Q IS VIRGINIA POWER'S ALTERNATIVE REGULATORY PLAN A TRANSITION TO RETAIL COMPETITION?

A No. Virginia Power's Plan does not propose retail competition. The Plan requests "full recovery" of all *transition* costs without recommending retail competition.[3] Thus, Virginia Power's Plan cannot fairly be described as a "transition" because Virginia Power has failed to include the end-point of such a claimed "transition"—retail customer choice. Virginia Power has not made any commitment to offer retail customer choice at the end of the "freeze." Thus, while the Plan is subject to many criticisms, which I discuss further in my testimony, at the very outset , it is important to emphasize that the Plan is in no way a "transition" to retail competition.

Q IF IT IS NOT A TRANSITION TO RETAIL COMPETITION, THEN WHY IS VIRGINIA POWER PROPOSING AN ALTERNATIVE REGULATORY PLAN AT THIS TIME?

A In requesting approval of its ARP, the Company states that it needs:

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[3] See Virginia Power's Response to Question No. 177 included in the Fifth Set of Interrogatories from the Office of the Attorney General, where the Company states: "It is a plan to recover costs first, with anything remaining after those costs have been recovered to the extent specified to be split between customers and shareholders. This is entirely consistent with full recovery of the previously unrecovered components of cost of service that make up the transition costs in this case."

> "... greater flexibility than exists under traditional rate regulation to ensure that the transition process treats all stakeholders fairly and enables the Company to remain financially viable by providing it with the opportunity to recover costs that were prudently incurred in the discharge of its public service mandate.
>
> ... This proposal would thus provide the flexibility Virginia Power needs to make an orderly transition to competition without impairing the Company's ability to meet its public service obligations reliably, efficiently and economically."[4]

Q CAN APPROVAL OF THE ALTERNATIVE REGULATORY PLAN BE JUSTIFIED ON THE ABOVE-STATED PREMISES?

A No. It is premature to provide now for an orderly transition when the evidence is so speculative that Virginia Power will sustain any adverse impact from retail competition. For example, Ms. Iverson's testimony demonstrates how Virginia Power's estimate of transition costs is highly sensitive to certain questionable assumptions, and how using different, but realistic, assumptions suggests the existence of *$2.7 billion of transition benefits*, instead of *$2.5 billion of transition costs*, for Virginia Jurisdictional customers. In other words, with those changes in assumptions, Virginia Power would be a competitive provider of generation services if all customers could choose their supplier(s).

The ARP also cannot be justified as a means of recovering generation-related regulatory assets because, according to Mr. Dooley's testimony, there are few such related assets that remain to be recovered. What is abundantly clear about the ARP is that it would be a dramatic departure from cost of service

[4] Virginia Power Application, Executive Overview, Pages 1 and 2.

ratemaking practices. As discussed later, this Plan fails to equitably balance the interests of Virginia Power's shareholders and its customers. Although it would provide Virginia Power with an opportunity to prepare for competition, nothing in the proposal would enable Virginia Power's customers either to prepare for, or benefit from, competition.

Q IS IT POSSIBLE TO DETERMINE, IN THIS PROCEEDING, HOW VIRGINIA POWER MIGHT BE IMPACTED BY RETAIL COMPETITION?

A No. There is no date certain for retail competition in Virginia. Many other key factors simply are unknown. We do not yet know whether all customers will immediately switch suppliers (i.e., a "flash cut" to customer choice), how a competitive market will be structured, whether prices will be transparent, whether incumbent utilities will remain vertically integrated and retain ownership of their existing generation resources, whether barriers to entry will prevent alternative generation suppliers and sales merchants from providing competitive services to end users–thereby keeping prices high, or the extent that Virginia Power can further mitigate costs, particularly its NUG resource costs.

Unless we know much more about these critical parameters, it would be premature to draw the kinds of conclusions that Virginia Power asks us to draw about the impact of retail competition on Virginia Power.

The Alternative Regulatory Plan Would Be A Dramatic
<u>Departure From Cost Of Service Ratemaking Practices</u>

Q WOULD THE ALTERNATIVE REGULATORY PLAN REPRESENT A DRAMATIC DEPARTURE FROM TRADITIONAL COST OF SERVICE REGULATION?

A Yes. According to VCFUR witness Dooley, Virginia Power currently is over-earning. With continued depreciation and the phase-down of certain purchased power contracts, Virginia Power is likely to continue to over-earn, unless rates are adjusted in this proceeding.

Thus, under the ARP, rates would be frozen at a level significantly above Virginia Power's actual cost of providing service. Further, these above-cost of service rates would be maintained for almost six years (from March 1997 though December 2002). Customers, thus, would be forced to relinquish hundreds of millions of dollars of rate reductions over the next five to six years in return for a promise of lower rates in year seven.[5] If traditional ratemaking practices were to continue, rates would be reduced to reflect the Company's lower costs. Furthermore, even Virginia Power's vague promises of lower rates in the future may be offset by the proposed "safety valve" that would permit a rate increase under certain circumstances.[6]

[5] Wright Direct Testimony, Page 12.

[6] Rigsby Direct Testimony, Page 39.

Q SHOULD MAJOR CHANGES IN RATEMAKING PRACTICES BE PREMISED ON SPECULATION ABOUT THE POTENTIAL IMPACT OF RETAIL COMPETITION?

A No. It would be inadvisable to implement dramatic changes in ratemaking practices, such as Virginia Power's ARP, based on premature speculation about the potential impact (or lack thereof) of retail competition. It has not been shown that any extraordinary treatment is needed to provide "an orderly transition to competition" or to prevent "impairing the Company's ability to meet its public service obligations reliably, efficiently and economically."

The Alternative Regulatory Plan Fails To Equitably Balance Customer And Shareholder Interests

Q DOES THE ALTERNATIVE REGULATORY PLAN PROVIDE AN EQUITABLE BALANCING OF INTEREST BETWEEN CUSTOMERS AND VIRGINIA POWER'S SHAREHOLDERS?

A No. The Plan, as proposed by Virginia Power, provides few, if any, customer benefits. On the contrary, it is significantly slanted in favor of shareholders through, for example, its *regressive* earnings sharing mechanism, which is discussed below.

Further, accelerating the recovery of *potentially stranded* costs, as the plan contemplates, should be justification alone to award a lower ROE. This extraordinary proposal would enable the Company to reduce future business and operating risks. The Company, however, has applied a "business-as-usual" approach by recommending the high end of its authorized regulatory return (i.e., 11.5%). Then, the Company allows its shareholders immediately to benefit by cost reduction efforts that would result in earnings in excess of a normal regulatory return.[7]

Q **HOW WILL VIRGINIA POWER'S SHAREHOLDERS BE THE PRIMARY BENEFICIARIES OF THE PROPOSED ALTERNATIVE REGULATORY PLAN?**

A Shareholders would have an opportunity to receive their ***full*** ROE and then some. First, all excess earnings above an 11.5% ROE up to a 13% ROE would be used to accelerate recovery of claimed generation-related regulatory assets. As proposed, this means that shareholders would fully recover any unrecovered regulatory assets. (Of course, since Mr. Dooley's testimony shows that the Company has overstated dramatically its claims regarding the existence of regulatory assets, the Company's proposal for full retention of excess earnings between 11.5% and 13.0% would leave the Company with a generous earnings cushion.) Second, 50% of any excess earnings above a 13% ROE would be retained by shareholders. In other words, 100% of the initial benefits from cost reduction efforts, which would raise Virginia Power's earned ROE above 11.5%, would be used to benefit shareholders. At the end of the proposed rate freeze, the Company's costs will be lower and its competitive position enhanced. Rather than providing "an opportunity for customers and shareholders to share in exceptionally strong financial performance," only when earnings rise to above the uppermost bandwidth (i.e., a 13% ROE) would customers see any reduction to their rate levels.

[7] Rigsby Direct Testimony, Pages 32-34.

As an indication of how unbalanced this proposal really is, the Company anticipates that customers would realize only **$************* of benefits during the five years, while shareholders would receive **$************* in benefits through the sharing mechanism together with **$************* of stranded cost recovery, plus **$************* return on the regulatory assets subject to accelerated recovery, for a total of **$************* of shareholder benefits.[8] (Immediately before the filing of this testimony, the Company notified us that it had modified its projections for a portion of the "freeze" period. The late notice did not afford any opportunity to update these totals.) **[********** INDICATES DELETION OF INFORMATION ALLEGED TO BE COMMERCIALLY SENSITIVE.]**

Q BUT WON'T THE ELIMINATION OF REGULATORY ASSETS ALSO BENEFIT CUSTOMERS?

A Any future benefit to customers is purely speculative and, at best, indirect. That is, customers may benefit indirectly in the future from reducing *potentially stranded* costs today, but this benefit is only speculative. The magnitude of Virginia Power's *transition* costs, if any, is exceedingly uncertain at this time. Again, there is no date certain for retail access to commence. Many issues, especially market power and market structure issues, have not been addressed, let alone resolved. More fundamentally, the Company assumes that customers would regard the writing down

[8] Response to Staff's First Set of Interrogatories, Question No. 120 **(Commercially Sensitive Information).** The Company's estimates are stated on a total, system-wide basis.

of *potentially stranded* costs as a benefit. In other words, the assumption is that it is beneficial to customers to forgo hundreds of millions of dollars of rate decreases in order to improve Virginia Power's competitive position. There is no such obligation.

Q **AREN'T CUSTOMERS OBLIGATED UNDER A "REGULATORY COMPACT" TO PROVIDE VIRGINIA POWER A REASONABLE OPPORTUNITY TO FULLY RECOVER ALL PRUDENTLY INCURRED COSTS?**

A No such regulatory compact ever has been committed to writing, either in Virginia or elsewhere in the U.S. Even Dr. Wright characterizes the so-called regulatory compact as an *implicit bargain*.[9] Traditional regulation, which provided a *surrogate* for competition, has granted utilities the *opportunity* to earn a reasonable return on their prudently incurred, used and useful investments. Further, I disagree with Dr. Wright's contention that the so-called compact requires consumers to bear all prudently incurred costs.[10] Regulation has never provided a *guarantee* that shareholders would realize such returns under any and all circumstances. In fact, regulators always have established utility rates of return in a manner that is designed to compensate utilities for the business risks that they incur. There is no legitimate basis to claim that the transition to retail competition should somehow create a ratepayer obligation to fully insulate utilities from any loss in revenues due to changes in the business environment. There is no mandate that all prudently

[9] Wright Direct Testimony, Page 5.

[10] Id. at Page 6.

incurred costs be fully recovered by a date certain. Further, a competitive market will allow utilities an opportunity to recover their costs and earn returns that not capped by price regulation.

Q. **BUT DOESN'T THE ONSET OF COMPETITION REPRESENT SUCH A CHANGE IN CIRCUMSTANCES THAT, IN FAIRNESS, UTILITY INVESTORS SHOULD BE PERMITTED FULL RECOVERY OF, AND A FULL RETURN ON, ALL PRUDENTLY INCURRED COSTS?**

A. No. There never has been such a "compact," as I discussed above. Further, the changes in the electric industry that will enable real competition to replace the regulatory surrogate at the generation and merchant levels did not occur overnight. The evolutionary process has been ongoing since the enactment of the Public Utility Regulatory Policies Act, in 1978, which created new opportunities for non-utility generators (NUGS). It has been sustained by continuing improvements in turbine technology, increasing competition in other formerly regulated industries (e.g. natural gas, long-distance telephone, rail, and trucking), the availability of abundant, low-cost natural gas and the Energy Policy Act of 1992 -- which expanded supply competition by allowing utilities to form "exempt wholesale generators" to market power at wholesale and enabled the FERC to order wholesale wheeling. Utility investors have been on notice for years that competition is coming to the electric industry, and today it is almost impossible to pick up any literature related to the electric industry without the subject being mentioned. The business risks associated with competition have been taken into account by the market for years.

Q VIRGINIA POWER STATES THAT ALTERNATIVE FORMS OF REGULATION HAVE "...ALREADY BEEN RECOGNIZED IN LEGISLATION ENACTED BY THE VIRGINIA GENERAL ASSEMBLY." DOES THE COMPANY'S PLAN MEET THE REQUIREMENTS OF THE ENACTED LEGISLATION?

A No, it does. In Va. Code, § 56-235.2 provides:

> "C. The Commission shall, before approving ... alternative regulatory plans under subsections A and B, assure that such action (I) protects the public interest, (ii) will not unreasonably prejudice or disadvantage any customers or class of customers, and (iii) will not jeopardize the continuation of reliable electric service.

Since the Company is requesting full recovery of specific transition costs over the five-year period, and full recovery of transition costs is not in the public interest, the Company's plan does not protect the public interest. Furthermore, the Plan will disadvantage all customer classes since it does not provide an equitable sharing of benefits between shareholders and customers. Finally, the Company has not proposed any measurable standards to benchmark service quality, reliability and safety. Without such benchmarks, and the necessary tools to enforce them, it will be impossible for the Commission to ensure that the Company is cutting costs, rather than cutting corners.

The Transition To Customer Choice And Protection Against Potential Market Power Abuses Should Be The Focus, Not ARP

Q ARE THERE ANY OTHER REASONS WHY THE COMMISSION SHOULD REJECT THE ALTERNATIVE REGULATORY PLAN?

A Yes. First, the proposed earnings sharing mechanism is *regressive*. That is, Virginia Power shareholders receive all of the initial benefits of cost reduction efforts, including full, accelerated recovery of regulatory assets. Second, the ARP represents a piece-meal change relative to the present rate base/rate of return form of price regulation. Rather than simplify matters, it is an unnecessary distraction in moving toward a customer choice environment. Finally, as discussed previously, recovery of *any* transition costs is premature. Allowing recovery to commence without concrete evidence of the existence, impact and need to recover transition costs from customers could prevent the Commission from adopting policies to foster a more competitive future.

Q WHAT IS MEANT BY A REGRESSIVE EARNINGS SHARING MECHANISM?

A A *regressive* sharing mechanism permits the utility to retain the first level of savings, but shares the benefits only after its earnings exceed the upper bandwidth, in this case, 13.0% ROE. Looking at this another way, it is apparent that the Company is using its share of excess earnings to enhance shareholder wealth rather than to lower rates. This contrasts with a *progressive* sharing mechanism in which customers receive all of the first level of savings but then gradually relinquish benefits to shareholders as the earned ROE exceeds the upper bandwidth. The Company's proposed regressive sharing mechanism is reason alone for the Company's proposal to be rejected.

Q HOW WOULD THE ALTERNATIVE REGULATORY PLAN BE A DISTRACTION FROM THE TRANSITION TO CUSTOMER CHOICE?

A An effective ARP would require close Commission monitoring of Virginia Power's performance in other key areas, including service quality, reliability, responsiveness to outages and requests for new installations and safety. Appropriate monitoring means first developing standards to measure performance in these (and possibly other) key areas and then providing the tools so that the standards can be enforced by this Commission. The Company has not proposed any such standards in this proceeding. It could take considerable time and effort, moreover, to develop them and even more time to implement and enforce them.

Q WOULD THE EFFORT TO DEVELOP SERVICE PERFORMANCE STANDARDS IN CONNECTION WITH AN ALTERNATIVE REGULATORY PLAN BE A GOOD USE OF THE COMMISSION'S TIME AND RESOURCES?

A No. In my opinion, it would not be worth the time and effort to develop meaningful performance standards when there is a preferable and more effective alternative. That alternative is competition. With competition, and specifically I mean customer choice, the market will provide the necessary discipline to ensure that customers receive the quality services that they demand at costs they deem reasonable and to generate the returns demanded by shareholders. If a supplier fails to perform, then the customer is free to choose a different supplier who will provide the service demanded by the customer. There is nothing more powerful than the threat of losing business to motivate a supplier to implement strict performance standards.

Further, considerable resources will have to be expended to successfully complete the transition from regulation to retail customer choice in a timely fashion. Thus, the Commission should focus its resources on the transition to customer choice, not on making piece-meal changes in regulation.

Q WHAT WOULD BE THE CONSEQUENCES OF ALLOWING A UTILITY TO COMMENCE THE RECOVERY OF TRANSITION COSTS NOW?

A If Virginia Power were allowed the opportunity to accelerate recovery of *potentially stranded* costs without concrete evidence that such an extraordinary procedure is needed to prevent undue and irreparable financial harm to the Company, then there is a real likelihood that the utility could over-recover *transition* costs. This would be poor public policy. It would greatly enhance Virginia Power's market power. Market power would be greatly enhanced by having a below-market cost structure, the retention of all of its generation assets and the use of these assets to sell electricity at unregulated prices and the proposed TCC, which would prevent customers from exercising competitive options available under current regulation.

Q WHAT GUIDELINES SHOULD THE COMMISSION FOLLOW IN THIS PROCEEDING TO ASSURE THAT THE TRANSITION TO CUSTOMER CHOICE

OCCURS IN A MANNER THAT MORE EQUITABLY BALANCES THE INTERESTS OF VIRGINIA POWER AND ITS CUSTOMERS?

A The Commission should establish Virginia Power's revenue requirements in this proceeding using traditional cost of service ratemaking practices. Rates should be set in this proceeding to recover Virginia Power's cost of service, no more and no less.

The Commission also should strive to ensure that there will be vigorous competition when customer choice commences. Deregulation of generation is only beneficial to the extent that it is replaced with workable competition, not unregulated monopolies. The Commission, therefore, must assure that no market participant has undue market power. Competitive options, including wholesale competition and cogeneration, should be maintained and expanded during the transition period to create a vibrant competitive generation market when choice is permitted. Certainly, existing choices available to customers should not be eliminated during the transition period. Eliminating existing choice (e.g., rate options, alternative supply options) only moves the industry further away from customer choice.

Q IS IT NECESSARY TO WAIT UNTIL TRANSITION COSTS ARE FULLY RECOVERED BEFORE ALLOWING CUSTOMER CHOICE?

A No. If choice does not begin until after recovery of transition costs is concluded, customers will be needlessly delayed access to new and innovative services and alternative suppliers during the transition period. Further, new suppliers will be denied the ability to develop relationships with new customers while the incumbent utilities, such as Virginia Power, are strengthening their customer relationships. Finally, the competitive pressures brought on with the introduction of customer choice can provide even stronger incentives to mitigate transition costs. This was precisely the experience in the natural gas industry.[11]

Q DOES VIRGINIA POWER'S ALTERNATIVE REGULATORY PLAN MEET THE GUIDELINES AND PRINCIPLES SET FORTH ABOVE?

A No. Virginia Power's ARP is premature because there is no concrete evidence that extraordinary measures are required to provide for an "orderly" transition to customer choice or to prevent the Company from suffering undue irreparable financial harm. The proposed ARP creates a potential for over-recovering *potential stranded* costs before any date certain is set for customer choice and prior to establishing a workable competitive market. The latter requires determining an appropriate structure and resolving any market power issues that may arise. Virginia Power's Plan also is heavily biased in favor of its shareholders. Virginia Power's ARP should be rejected.

[11] According to the Interstate Natural Gas Association of American, stranded costs in the gas industry turned out to be significantly less than expected, $13.2 billion vs. $44.0 billion, because open access commenced prior to the resolution and recovery of transition costs. See Interstate Natural Gas Association of America Rate and Policy Analysis Department, "Background Report: Comparison of Gas and Electric Industry Restructuring Costs," Report No. 96-2, August 1996.

2. QUANTIFICATION AND RECOVERY OF TRANSITION COSTS

Q PLEASE SUMMARIZE VIRGINIA POWER'S PROPOSALS WITH RESPECT TO THE QUANTIFICATION AND RECOVERY OF TRANSITION COSTS.

A Virginia Power is proposing the approval in principle of recovery of 100% of remaining *transition* costs through a TCC. It is also proposing that the Commission approve a methodology for estimating *transition* costs in this proceeding.

Q SHOULD ANY OF THESE PROPOSALS BE ADOPTED?

A No. The Commission should reject the Company's proposals. The proposals are premature. As discussed above, retail customer choice is not in place and the Company has provided no showing of need. There is far too little knowledge of the impact of a customer choice regime on the value of the Company's generation assets and NUG contracts to determine whether the proposed TCC would promote, rather than impede, a competitive market or fairly balance the interests of Virginia Power's customers and shareholders. On the other hand, as discussed further, adopting a TCC would be poor policy because:

- ➢ Virginia Power has failed to make any distinction between *potentially stranded* costs and *transition* costs;
- ➢ Implementing the TCC now would remove any incentive for Virginia Power to mitigate such costs between now and the time retail competition commences;
- ➢ The TCC and the potential imposition of exit fees would be anti-competitive; and

- Full recovery of transition costs would be unfair to consumers because it fails to balance their interests against the interests of the Company. It certainly is not mandated under any regulatory compact.

The methodology for estimating transition costs also should be rejected for the reasons stated in Ms. Iverson's testimony. In addition, the methodology relies on an administrative approach to quantify transition costs. Similar administrative approaches were used to project long-term avoided costs that were then used to price the Company's NUG power purchases. In light of the inability of such methods to accurately foresee major events affecting the future cost of electricity, such as technological changes and the abundance of low-cost natural gas, and its extreme sensitivity to changes in the assumed market prices, the Commission should categorically reject the Company's proposed administrative methodology in this case. If any methodology is to be approved, then it should be based on a market valuation approach. I shall discuss how market-based methodologies are superior to administrative approaches in quantifying transition costs.

Any Quantification Of Transition Costs Is Premature At This Time

Q WHY SHOULD ANY METHODOLOGY FOR QUANTIFYING TRANSITION COSTS NOT BE APPROVED AT THIS TIME?

A First, as previously stated, the Company's definition of *transition* costs includes all costs that may be unrecoverable for whatever reason, including customer choice. *Transition* cost recovery, if done properly, would include only *transition* costs associated with customer choice. Second, the Company admits it is not possible to quantify *transition* costs with precision because market prices cannot be predicted with any accuracy or reliability.[12]

The existence of *transition* costs cannot be established absent an in-depth analysis of the market value of a utility's generation resources *and* specification of a date certain for retail customer choice. Market value cannot be determined without knowing the structure of a competitive market as well as the projected supply and demand for electricity. To my knowledge, none of these parameters is known and measurable today. There is no date certain for retail access. No determination has been made about how retail access will be implemented—immediately for all consumers or as a phase-in. The structure of a competitive market has not been established. Whether and to what extent utilities may exert horizontal and vertical market power and, therefore, influence prices in a competitive market has yet to be considered.

Further, as Ms. Iverson's testimony demonstrates, the Company's methodology is based on very specific, and as yet unknown, parameters about the date certain for retail access, market structure and speculative estimates of future loads and costs. These problems are in addition to the flaws inherent with any administrative determination of future costs, as discussed below.

Absent these critical elements, no determination can be made about an appropriate methodology for quantifying potential *transition* costs.

[12] Rigsby Direct Testimony, Page 46.

<u>Transition Cost Charge</u>

Q WHAT COSTS IS VIRGINIA POWER SEEKING TO RECOVER THROUGH THE TRANSITION COST CHARGE?

A Virginia Power states that it is seeking full recovery of all *transition* costs within seven years of the commencement of retail access. In addition, nuclear decommissioning expenses would be collected through the Transition Cost Charge (TCC) over the remaining life of Virginia Power's nuclear plants.

Q DO THE COSTS VIRGINIA POWER SEEKS TO RECOVER THROUGH THE TRANSITION COST CHARGE SOLELY REFLECT THE IMPACT OF RETAIL COMPETITION?

A No. The methodology it proposes to use to quantify *transition* costs—which it is seeking Commission approval in this proceeding—measures *potentially stranded* costs. As discussed previously, *transition* costs are uneconomic costs arising *solely* because of the transition to retail customer choice. It is wrong to equate *potentially stranded* costs with *transition* costs because the former assumes that all uneconomic costs will be the result of retail customer choice. This ignores the fact that stranded costs may arise for a variety of reasons that are unrelated to the implementation of customer choice. Virginia Power's definition also ignores the fact that uneconomic costs can be either avoided or mitigated. As Ms. Iverson demonstrates, several of the items included in Virginia Power's definition of *transition* costs include costs that are mitigable and avoidable. These items should not be included in the TCC.

Q WHY IS IT IMPORTANT TO DISTINGUISH BETWEEN TRANSITION COSTS AND POTENTIALLY STRANDED COSTS?

A Virginia Power always has faced competition for its generation services from various forms of self-generation. Since at least 1978, moreover, when the Public Utilities Regulatory Policy Act (PURPA) was adopted, Virginia Power has faced competition from NUG suppliers. Generation competition has intensified following the adoption of the Energy Policy Act of 1992. Like most utilities, Virginia Power faces more intense competition in the wholesale market. Suppliers are also positioning themselves for the eventual implementation of retail competition. It is this very type of existing and anticipated competition that has helped to force regulated utilities to cut costs and to offer their customers a broader array of rates and service options, such as RTP. The Commission should not sanction recovery of stranded costs associated with these and other options that are possible in the current environment. To do so would unnecessarily insulate Virginia Power from current operating risks for which investors are being compensated.

Q HAS THIS ISSUE BEEN CONSIDERED IN OTHER FORUMS?

A Yes. In Order No. 888, the Federal Energy Regulatory Commission (FERC) expressly made clear that the opportunity for a utility to recover stranded cost was restricted to situations in which the utility faced the loss of a customer due to new competitive options directly created by the opening of the wholesale market, not options that had previously existed. The FERC stated that it would not "insulate a utility from the normal risks of competition, such as self-generation, cogeneration, or industrial plant closures, that do not arise from the new availability of non-discriminatory open access transmission."[13] The same policy should apply to this case.

Q **WHY WOULD IMPLEMENTING A TRANSITION COST CHARGE IN CONCEPT IN THIS PROCEEDING REMOVE VIRGINIA POWER'S INCENTIVE TO MITIGATE TRANSITION COSTS?**

A As an example, Virginia Power is presently engaged in negotiations with its NUG suppliers to lessen the impact of these contracts on future expenses.[14] The outcome of these contract negotiations is in doubt and is unlikely to be fully resolved by the time this proceeding concludes. **If the Commission, today, were to provide assurance of full recovery of transition costs commencing at some time in the future, then it would remove Virginia Power's incentive to exert maximum effort to mitigate these potentially significant costs.** Further, if the NUGs are aware that Virginia Power is assured of 100% recovery of costs associated with their contracts, what possible incentive would they have to negotiate reductions in those costs with Virginia Power?

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[13] FERC; Docket Nos. RM95-8-000 and RM 94-7-001, Order No. 888, April 24, 1996, p. 454.

[14] "Report of Virginia Electric and Power Company on Efforts to Restructure Contracts with Non-Utility Generators, Case No. PUE950089," dated June 2, 1997 and attached to Virginia Power's response to Question No. 179 included in the Fifth Set of Interrogatories from the Office of the Attorney General.

Q HOW WOULD THE TRANSITION COST CHARGE BE ANTI-COMPETITIVE?

A The proposed TCC, or in the alternative, an exit fee, would be levied on customers that may opt for self-generation, an option that is available in the present regulatory environment. Besides compensating Virginia Power twice for the risks it incurs today, imposing TCCs on self-generation options would discourage the development of competitive alternatives, contrary to PURPA, the Energy Policy Act of 1992 (EPAct) and FERC Order No. 888, and would unnecessarily enhance Virginia Power's market power. Under Virginia Power's proposed TCC on self-generation options, moreover, it also appears that the customers' motives for electing self-generation options would be scrutinized. Mr. Hilton's testimony states that the TCC would apply "[t]o the extent the implementation of electric industry restructuring and retail competition made it legally possible for a customer to economically discontinue reliance on the system grid for its power supply . . . ."[15] Subjecting a utility customer to an inquiry into whether it has pursued self-generation options as a result of restructuring the electric industry or as a result of other business factors could involve a highly subjective, potentially complex undertaking, and a potentially expensive and burdensome one for the customer. <u>Granting a utility</u> the opportunity to scrutinize its customers' business decisions could open customers to scrutiny in a way that is highly intrusive and anti-competitive.

[15] Hilton testimony, Page 17.

Q **HOW WOULD VIRGINIA POWER'S PROPOSALS IN THIS CASE FURTHER ENHANCE ITS MARKET POWER?**

A Market power would be enhanced by regulatory policies that prevent or eliminate potential competition or provide for excessive recovery of costs claimed to be "*transition*" costs on the basis of false claims that they are, in fact, a result of a transition to retail competition. As mentioned above, imposing any kind of charge or exit fee on customers who may choose to exercise alternatives that are possible within the current regulatory regime would be anti-competitive. For this reason alone, the proposed TCC should be rejected.

Overcompensating Virginia Power for its transition costs has the potential of transforming the utility into a "super-competitor." A super-competitor is any entity that can profit by selling at below-market prices. By overcompensating Virginia Power for its alleged transition costs, the value of its assets would fall below the value that could be supported in a competitive marketplace. Virginia Power, thus, could utilize the very same assets to sell electricity at below-market prices, thereby stifling competition. Under these circumstances, investors would be compensated twice: once during the recovery of transition costs, and a second time through higher profits from the utilization of the very same assets in a competitive market.

Q **CAN THE TRANSITION COST ISSUE BE RESOLVED WITHOUT ADDRESSING AND RESOLVING POTENTIAL MARKET POWER ISSUES?**

A No. If retail competition is to benefit all consumers, electric utilities should not be allowed to exert market power. ***Protections against the abuse of vertical and horizontal market power should be implemented to ensure the evolution of sustainable competitive markets.*** Regulators in the United Kingdom (UK) and in the U.S. (such as those in California and Maine) that have initiated the transition to electric competition have recognized that market power is a significant problem in electricity markets, and that market power abuse can lead to market distortions that reduce the benefits to consumers of implementing retail customer choice.

For example, the newly elected Labour Party government in the UK has raised the possibility of requiring asset divestiture by the UK's two largest generation companies to reduce the level of concentration in that country's generation markets.[16] Discussion of such action follows widespread criticism by many in the UK that the country's electric industry restructuring did not produce the expected level of price reductions for consumers due to generation market concentration levels that allowed price leadership and collusion to take place among generation companies, particularly in the bidding procedures for the UK's generation power pool.

In California, the Public Utilities Commission ordered Southern California Edison Company and Pacific Gas and Electric Company, the State's two largest utilities, to divest at least 50% of their fossil-fired generation capacity in order to

[16]The Electricity Daily, Labour Sweep Causes Heartburn, Volume 8, Number 86, May 6, 1997.

mitigate generation market power problems.[17] Southern California Edison Company has, in fact, gone beyond this requirement, and is now in the process of selling off all of its in-state fossil-fired generation. A similar asset sale has already been completed by the New England Electric System (NEES) in the context of this utility's restructuring plan. Other utilities, such as General Public Utilities and Montana Power Company, have announced plans divest themselves of their generation assets and to exit the generation business.

These examples underscore the importance of the market power issue to electric industry restructuring. There are several significant factors that can form barriers to entry into electricity markets and create potential market power problems, including transmission constraints and excessive market concentration levels. To ensure workable competition in the electric industry, Virginia should be prepared to take measures to reduce these barriers.

Q WOULD MARKET POWER CONCERNS BE ALLEVIATED IF THE COMMISSION WERE TO PERMIT FULL RECOVERY OF VIRGINIA POWER'S TRANSITION COSTS?

A No. It should be recognized that incumbent utilities have significant, tactical and strategic advantages over new entrants. First, under present law, only electric

[17] *See* California Public Utilities Commission, Docket Nos. R.94-04-031 and I.94-04-032, Order Instituting Rulemaking and Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation, Decision No. D.96-01-009, Jan. 1996.

utilities have the right of eminent domain. Second, incumbent utilities have the advantage of name recognition. They also possess extensive and detailed information concerning customers' load profiles and usage characteristics. Continual contact with customers has enabled the utilities the opportunity to better understand customers' wants and needs. Incumbent utilities also have the advantage of scale economies, and they own an extensive infrastructure that supports the production, delivery and sale of electricity to end-users.

Q WHAT ARE SOME OF THE ADVANTAGES ENJOYED BY INCUMBENT ELECTRIC UTILITIES WITH RESPECT TO THE EXISTING INFRASTRUCTURE?

A For example, generation plant sites are strategically valuable. First, there are a limited number of sites that can support generation. Most of the existing generation plant sites were chosen because of their proximity to indigenous fuel supplies, load centers or available cooling water, their accessibility to major transportation corridors and the ability to obtain necessary environmental permits. Additionally, incumbent utilities have built, operate and maintain a bulk power system to transmit and deliver power from generating stations to distribution load centers.

Given the existing infrastructure, incumbent utilities have a further advantage of scale economies. That is, generally it would be cheaper to increase capacity at an existing plant site rather than to add a new "green field" site. It may also be much cheaper to repower existing plants than to build totally new capacity.

Q WHAT ARE THE IMPLICATIONS OF THE STRATEGIC AND TACTICAL ADVANTAGES ENJOYED BY INCUMBENT ELECTRIC UTILITIES?

A The implication is that full recovery of potentially stranded costs would allow incumbent electric utilities to gain additional substantial strategic, tactical and cost advantages over their competitors. In other words, it will transform a high-cost, non-competitive supplier into a super-competitor. Such a transformation would not be in the public interest because it would place existing low-cost electric utilities and other market players at a significant competitive disadvantage. In the end, full recovery only will result in less competition.

Q WHAT REGULATORY POLICIES MAY PREVENT A UTILITY FROM UNDULY ENHANCING ITS MARKET POWER DURING THE TRANSITION TO COMPETITION?

A Functional and operational unbundling are essential to ensure a level playing field among competitors in the generation and merchant functions, and to ensure non-discriminatory open access to transmission and distribution facilities for all retail customers. However, taking this step alone has serious shortcomings. Despite the implementation of open access tariffs and utility codes of conduct in FERC Order No. 888, it must be recognized that utility transmission and distribution operations continue to report to the same management and remain owned by the same parent company that in the future will be engaged in competitive activities through affiliated entities. Therefore, functionally unbundled transmission and distribution units have more than just a passing interest in the well-being of their generation and power merchant affiliates.

Possibly the only means of eliminating this conflict of interest is through complete structural separation of the utility's monopoly and competitive functions (i.e., divestiture). In California, the utilities agreed, in principle, to divest a portion of their generation assets as a means of mitigating their market power. Other utilities, like the NEES, have voluntarily divested their generation assets. Besides mitigating market power, this action was a quid pro quo for receiving favorable resolution of the transition cost issue.

Q WHAT GUIDELINES SHOULD BE EMPLOYED TO RESOLVE THE ISSUE OF TRANSITION COSTS IF A LEGITIMATE PROBLEM WERE TO ARISE?

A The Commission should adopt appropriate guidelines to ensure an equitable balancing of the interests of all stakeholders in a contested proceeding.

The utility's claims must be subject to quantification and verification. The analysis must consider the value of resources over their remaining useful lives. Second, because some assets will have a market value higher than their associated net book value (NBV), it is essential to net these above-market assets against the remaining below-market assets.

As mentioned earlier, just because a particular cost is *potentially strandable* does not justify a need to assure recovery when retail competition commences. If the utility has a reasonable opportunity either to mitigate or avoid incurring a *potentially strandable* cost, then no special compensation would be necessary or appropriate. Examples of costs that can be avoided or mitigated include:

- Future administrative and general expenses;
- Revenue-related expenses;
- Fuel supply contracts; and
- Ongoing operation, maintenance and fuel costs associated with resources in which continued operation may not be economic.

For example, Ms. Iverson has determined that Virginia Power has allocated present levels of administrative and general and other corporate overhead expenses in determining the value of its existing resources. There is no evidence to support any stranding of Virginia Power employees as a consequence of customer choice. Further, no such estimate of overhead expenses was reflected in the projected market prices. Thus, Virginia Power's analysis may compare apples to oranges.

As previously noted, it is also reasonable to conclude that utilities were fully aware of impending competition in retail electricity markets by no later than October 1992, the date of enactment of the EPAct. The EPAct established a national policy of expanding competition in the electric industry. Utility shareholders have had more than adequate warning by that time that any new investments could be rendered uneconomic by increased competition in the industry. Thus, uneconomic investments made after October 1992 should be expressly excluded from consideration. Similarly, any claims of *transition* cost recovery associated with the advent of wholesale competition in electricity markets should be excluded from consideration.

Finally, as discussed earlier, costs that are *strandable* in the current environment should not be included in any transition charge that might ultimately be adopted.

Thus, it is clear that the application of these criteria would limit retail transition cost recovery to only those sunk, fixed generation-related utility investments that would become uneconomic solely due to retail customer choice. They also would preclude defining utility *transition* costs based on any and all revenues lost by the utility due to a retail customer's decision to select an alternative generation provider. There is no justification whatsoever to equate retail transition costs with lost revenues because not all costs included in present and future rates will be unrecoverable in a post-regulatory environment.

Full Recovery Of Transition Costs Is Not
Sanctioned Under Any So-Called Regulatory Compact

Q IS IT YOUR UNDERSTANDING THAT THE A "REGULATORY COMPACT" MANDATES THE OPPORTUNITY FOR RECOVERY OF AND A RETURN ON ALL PRUDENTLY INCURRED COSTS FROM CUSTOMERS UNDER ANY AND ALL CIRCUMSTANCES?

A No. There is considerable regulatory precedent for the concept of cost sharing between customers and investors, even when the decision to make a particular investment was prudent. For example, in ruling that the unamortized losses associated with three abandoned nuclear plants, Surry Units 3 and 4 and North Anna Unit 4, should not be included in the rate base, this Commission stated that:

> Traditional business practice, as well as economic theory, demands that the ratepayers not bear this entire investment burden. The fact that VEPCO is a regulated monopoly does not mean, *and has never meant*, that the ratepayer rather than the investor must bear the investment risks.[18]

The Commission further articulated this policy in a subsequent decision:

> ...the Commission was at pains to carefully balance the interests of shareholders and ratepayers with regard to these [nuclear plant] cancellations. The Commission recognized that someone would have to pay for the loss of these projects, which were originally intended to benefit both shareholders and ratepayers, and that it was not fair to insulate either group entirely from the financial effects of the abandonment.
>
> The balance which the Commission struck was that, although the investors would be allowed to recover the actual <u>cost</u> of the projects from the ratepayers over a reasonable period of time, the ratepayers would not have to pay, and the investors would therefore lose, any <u>return</u> on that cost.[19]

Many other state regulatory commissions have approved similar cost sharing arrangements by allowing the recovery of plant abandonment costs but denying a return on the unamortized balance.[20]

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[18]Virginia State Corporation Commission, "Application of Virginia Electric and Power Company To Revise its tariffs, Final Order," Case No. PUE810025, August 24, 1981. Emphasis added.

[19]Virginia State Corporation Commission, "Application of Virginia Electric and Power Company To Revise its Tariffs, Final Order," Case No. PUE840071, May 16, 1986.

[20]NARUC, <u>Utility Regulatory Policy In The United States and Canada</u>, Compilation 1992-1993, Table 34.

Recently, in a case in which I was involved, the Public Utility Commission of Texas (PUCT) adopted a similar cost sharing approach in determining that utilities were not entitled to full recovery of their "excess cost over market" (or ECOM) associated with an operating nuclear plant:

> In its mandated role as a substitute for competition, the Commission pursuant to §2.203 [of the Public Utility Regulatory Act] must in each rate proceeding set overall revenues at a level to provide a reasonable opportunity to earn a reasonable return on invested capital used and <u>useful</u> in rendering service. ***ECOM is inherently economically and technologically unuseful, or at a minimum less useful in rendering service.*** Under the "used" standard, the Commission has exercised its authority to balance equities by allowing recovery of capital costs by eliminating or reducing the return on assets previously found prudent, but no longer used. The same rationale may be consistently applied when assets are unuseful. [bold emphasis added][21]

Thus, it is clear that shareholders have always had to bear investment risk, such as an abandoned plant or a facility that is rendered uneconomic.

Q VIRGINIA POWER CLAIMS THAT FULL RECOVERY OF STRANDED COSTS IS ESSENTIAL TO MAINTAINING ITS FINANCIAL INTEGRITY. HOW DO YOU RESPOND TO THIS ARGUMENT?

A This argument rests entirely on speculation. Beyond the speculativeness of the "transition costs" themselves, Virginia Power has not even attempted to show the impact of competition on its financial integrity. The aggressive overseas and domestic investment activity of many U.S. electric utilities, including Dominion

[21] Public Utility Commission of Texas, "Application of Central Power and Light Company for Authority to Change Rates, Order on Rehearing," Docket No. 14965, Page 2.

Resources, Virginia Power's parent company, belies current assertions about threatened financial viability. Rather than being needed to stave off utility bankruptcies, full transition cost recovery would create a source of risk free cash that Virginia Power could use to compete against other suppliers.

Virginia's electricity consumers should not be required to subsidize the unregulated business ventures through claimed "transition cost" recovery.

Equitable Sharing Of Transition Costs

Q ARE THERE LEGITIMATE POLICY REASONS FOR REQUIRING THAT THE BURDEN OF ANY RECOVERY OF TRANSITION COSTS BE SHARED BETWEEN CUSTOMERS AND REGULATED UTILITIES?

A Yes. Electric utilities have an obligation and a responsibility to mitigate *transition* costs. If utility shareholders are required to bear some risk associated with *transition* cost recovery, they will have a strong incentive to reduce the level of these costs, which will inure to the benefit of both customers and shareholders.

Q DO YOU BELIEVE THAT THE SHARING OF TRANSITION COSTS BETWEEN CUSTOMERS AND INVESTORS WOULD BE CONTRARY TO A "REGULATORY COMPACT"?

A No. Regulators today are facing a dilemma with respect to so-called *transition* costs that is similar to the dilemma they faced in the 1970s and 1980s when numerous electric utilities canceled major construction projects and requested full-cost recovery from customers. The response then was to require cost sharing as a means of balancing the interests of customers and investors. Even when the decision to make a particular investment was prudent, regulators allowed utilities to recover plant abandonment costs, but they denied a return on the unamortized balance. This was precisely the outcome that the PUCT reached in denying full recovery of transition costs.

Nothing has changed that would affect the requirement that regulators must continually balance customers' and investors' interests in deciding the issues arising in ratemaking and other proceedings. Thus, mandatory recovery of all *transition* costs from customers would be fundamentally at odds with this long-standing regulatory precedent. Based on the foregoing, the equitable sharing of *transition* costs between customers and shareholders would provide a reasonable balance of the interests of both investors and consumers in the transition to retail competition.

<u>Administrative vs. Market-Based Approaches</u>

Q **IN HER TESTIMONY, MS. IVERSON CHARACTERIZED VIRGINIA POWER'S METHOD OF QUANTIFYING STRANDED COSTS AS AN ADMINISTRATIVE APPROACH. SHOULD THIS COMMISSION SANCTION AN ADMINISTRATIVE QUANTIFICATION OF TRANSITION COSTS?**

A No. The quantification of transition costs necessarily depends on the expected level of competitive market prices for electricity and the future operating costs of existing generation assets. These parameters are difficult to predict even when such variables as a date certain for retail access, market structure and market power issues have been determined. The difficulty in accurately forecasting avoided costs in the mid-1980's further demonstrates the folly of such an administrative approach to quantification.

Administrative determinations of transition costs are necessarily judgmental and will be subject to considerable scrutiny in regulatory proceedings such as this case. The fact that any forecast of market value will be wrong will, in turn, spawn a new round of regulatory proceedings to "true-up" the level of transition cost recovery based on new evidence regarding market prices. This highly controversial and highly politicized process would result in a large and wasteful expenditure of resources by industry stakeholders. The Commission should reject this approach.

Q WHAT APPROACH SHOULD BE USED TO QUANTIFY TRANSITION COSTS?

A To the extent possible, *transition* costs should be quantified using objective market valuations of generation assets such as asset sales, stock valuations, auctions, or similar means to establish the appropriate level of transition costs. Market mechanisms provide an objective measure of the market value of assets, and the use of such mechanisms can avert the need for prolonged legal proceedings to establish speculative, administratively determined market price levels to quantify *transition* costs.

Q **WHAT ARE SOME OF THE WAYS THAT THE MARKET CAN DETERMINE THE VALUE OF A UTILITY'S RESOURCES?**

A One example would be to quantify *transition* costs through arms-length, competitive asset sales to third parties. Under this approach, the *transition* costs associated with the sold assets would be determined by offsetting the sale price of the assets against their NBV. Such asset sales could be phased-in over time to ensure that they are not sold at "fire sale" prices. As previously stated, this approach was successfully implemented by NEES in its recent divestiture of all of its generation resources, which also included the assumption of purchased power contracts. The net proceeds from the sales will be used to reduce the recovery of transition costs from NEES' customers.[22]

Alternatively, transition costs may be quantified through stock valuations if the incumbent utility spins-off its generation assets to a separate, publicly traded affiliated or non-affiliated corporation. Under this method, the market price of the assets would be determined by using the average daily closing price of the stand-alone generation company's common stock over a specified period of time. The utility's transition costs then would be determined by offsetting this stock price against the NBV of the utility's generation assets.

[22] "NEES' Stranded-Cost Charges Expected to Drop as USGEN Buys Generating Assets," Industrial Energy Bulletin, July 22, 1997, p. 4.

Q WHAT ARE THE ADVANTAGES OF A MARKET-BASED QUANTIFICATION OF TRANSITION COSTS?

A First and foremost, market based approaches avoid the guesswork inherent in administrative quantifications. Second, a market approach necessarily would require some degree of separation of existing generation-related assets in the case of a spin-off or divestiture in the case of an asset sale. Either a separation or divestiture would mitigate potential market power concerns. Thus, two key issues—the quantification of transition cost and the mitigation of market power—can be resolved simultaneously .

Finally, the California and New England asset sales and the announcement of over 13,000 megawatts of "merchant" power plants are evidence of a vibrant generation market. [23] (A merchant plant is generation in which the capacity is not already committed to a purchaser at the time of construction.) These experiences, coupled with the resolution of potential market power problem, should alleviate concerns that existing assets would not be properly valued.

[23] "The Electricity Daily," September 2, 1997.

3. UNBUNDLING OF RATES

Q **VIRGINIA POWER HAS FILED TWO SETS OF ILLUSTRATIVE UNBUNDLED TARIFFS IN THIS PROCEEDING. HAVE YOU REVIEWED THESE TARIFFS?**

A Yes. The first set of unbundled tariffs (Exhibit No. AGE-___, Schedule 7) separates the rates and charges into customer, demand and energy components based on rate of return parity. The demand components were further separated between production, transmission and distribution functions.

The second set of tariffs (Exhibit No. AGE-___, Schedule 9) is similar to the first set, except for the additions of the TCC and Ancillary Service charges to replace the Production and Energy charges. Virginia Power represents that the Ancillary Service charges were based on the same charges that have been approved by the FERC, in Docket No. OA97-52-000.

Q **SHOULD THE COMMISSION REQUIRE VIRGINIA POWER TO REQUIRE UNBUNDLING OF ITS TARIFFS IN THIS PROCEEDING?**

A Yes. Virginia Power should be required to unbundle its existing rates in this proceeding for informational purposes. I am not recommending that any rates should necessarily be changed in total, unless the Commission were to authorize a general rate change. Unbundling will provide a first step in the transition to customer choice because customers now will be aware that their electricity service actually is comprised of many individual services. These individual services include generation, transmission and distribution wires (i.e., capacity-related services), metering and billing (i.e., customer-related services), and fuel and variable operating and maintenance expenses (i.e., energy-related services). In addition, supporting the generation and delivery functions are the various Ancillary Services.

When customer choice is implemented, customers will have an opportunity to purchase generation services from suppliers other than Virginia Power. Certain delivery and ancillary services also may be required. However, every customer may not require precisely the same services. Some industrial customers, for example, may utilize self-generation or third party providers to follow their load or to provide reactive power. These customers may not require Virginia Power to provide generation, load following or reactive power, and they should not have to pay for them.

Further, it is possible that many of the unbundled services will be provided competitively by multiple suppliers, in addition to Virginia Power. For example, scheduling, system and control and dispatch, regulation and frequency response, spinning reserve, supplemental reserve and metering and billing services could be competitively sourced.

Q WHY ELSE SHOULD THE COMMISSION REQUIRE VIRGINIA POWER TO FULLY UNBUNDLE ITS RATES?

A Requiring all electric suppliers to unbundle rates into discrete components will enable prices for each competitive service to become more transparent in the marketplace. Price transparency is an essential ingredient of a competitive market. For those services which will remain natural monopolies or where a competitive market has not developed, the unbundled prices would reflect the actual cost of providing each service. Cost-based rates will send the appropriate price signals to customers and prevent suppliers from using their monopoly services to subsidize competitive services as a means of gaining market share.

Thus, rate unbundling is essential to achieving and maintaining a fully competitive market that will allow customers to choose appropriate service options.

Finally, by minimizing opportunities to shift costs between competitive and regulated operations, unbundling also will help to mitigate attempts by electric utilities to exert market power.

Q SHOULD ANY OTHER DISCRETE SERVICES BE UNBUNDLED?

A Yes. The illustrative tariffs presented by Mr. Evans recognize, for example, that Power Supply should be unbundled into Production and Transmission. However, all services which will not necessarily remain natural monopolies should be unbundled and separately priced. Examples of these services include metering, billing, and customer information services. Explicitly unbundling these services will allow competing suppliers to provide them directly to customers.

Further, decommissioning costs, taxes and other governmental levies, and public policy programs should be separately stated in the unbundled tariffs. This will provide appropriate information for customers to better understand all of the factors that comprise the cost of electricity. It is possible that metering and billing services eventually could be competitively sourced.

For these reasons, in addition to the informational unbundling of rates in this proceeding into Production, Transmission, Distribution, and Energy, the Commission should order Virginia Power to file—within 60 days of the Commission's final order in this case—an application to further unbundle customer costs into metering and billing components and to separately price decommissioning costs, taxes and other governmental levies, and public policy programs.

Q DO YOU HAVE ADDITIONAL POLICY CONCERNS REGARDING THE ILLUSTRATIVE TARIFFS FILED BY VIRGINIA POWER?

A Yes. In his testimony, Mr. Evans has raised the possibility that changes could be made to the unbundled rates before actual billing could occur.[24] He cites the FERC's Order of February 25, 1997, in Docket No. ER97-960-000, in which a proposal by Washington Water Power Company (WWP) to set the transmission component of an unbundled retail tariff at the level currently reflected in WWP's

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[24] Evans testimony at Page 25.

retail rates was denied. Specifically, the FERC is requiring that the transmission unbundled rate be set at a level consistent with WWP's Open Access Transmission Tariff (OATT) filed in compliance with Order No. 888.

Q WHAT ARE THE IMPLICATIONS OF FERC'S ACTIONS FOR THIS PROCEEDING

A Retail competition is not being implemented as part of this proceeding. Rather, VCFUR only is requesting that Virginia Power be required to unbundle its tariffs for informational purposes. Thus, the Commission need not address, in this proceeding, the issues raised by the WWP case.

However, Mr. Evans' testimony on this topic highlights an issue that will need to be addressed as part of any subsequent implementation of retail customer choice. We estimate that using Virginia Power's OATT would cause Virginia Power's transmission revenue requirements to increase by $12.4 million per year relative to its test year embedded transmission cost of service. In other words, unless further actions were taken, Virginia Power would receive a $12.4 million per year windfall if the FERC requires the use of its Order 888 OATT charges for determining the unbundled cost of providing retail transmission service.

Q WHAT IMPACT DOES THIS ISSUE HAVE ON VIRGINIA POWER'S TRANSITION COST PROPOSALS?

A Mr. Evans' testimony on this issue provides another example of why Virginia Power's Transition Cost proposals are untimely and should be rejected in this proceeding. For example, one way to address this issue—to prevent Virginia Power from benefiting from a $12.4 million windfall—would be to allow Virginia Power to apply the FERC-approved firm transmission rates, but require that a portion of the revenues be used to offset other non-transmission related revenue requirements. Because all customers require the use of the transmission system, the most appropriate options would be to require an offsetting reduction to the unbundled Production charge. If the Commission were to impose a TCC once retail customer choice is implemented, then this charge should also be reduced to offset the corresponding increase in the unbundled retail Transmission charge.

Consequently, the resolution of this issue in a subsequent proceeding will impact any TCC mechanism. This further illustrates why it is inappropriate to establish a TCC in a vacuum, as requested by Virginia Power in this case.

4. CLASS REVENUE DISTRIBUTION

Q IF BASE RATES ARE TO BE CHANGED IN THIS PROCEEDING, HAVE YOU PREPARED AN EXHIBIT TO SHOW HOW THE CHANGE WOULD BE DISTRIBUTED AMONG THE VARIOUS CLASSES, CONSISTENT WITH THE COMMISSION'S REVENUE DISTRIBUTION GUIDELINES?

A Yes. The illustration is shown in Exhibit ___(JP-1). It is based on the Company's Average and Excess (A&E) cost of service study. For illustrative purposes, I have assumed a $200 million reduction.

Q WHAT REVENUE DISTRIBUTION GUIDELINES HAS THE COMMISSION ADOPTED IN PRIOR CASES?

A The Commission's long-standing policy has been to move each class toward parity, to within a ± 10% bandwidth of the overall jurisdictional rate of return, while also recognizing the need to apply gradualism to avert rate shock, by limiting the percentage change to a maximum of 150% of the overall percentage change in rates.[25]

Q WHAT IS THE RESULT OF APPLYING THESE GUIDELINES?

A Page 1 of Exhibit____ (JP-1) shows the resulting base revenue distribution by customer class, while Page 2 compares the cost of service study results before and

[25]State Corporation Commission, Final Order, Application of Virginia Electric and Power Company For a general increase in rates, Case No. PUE920041, Pages 19 and 20; February 3, 1994.

after the rate reduction using the Commission's revenue distribution guidelines. In order to move all of the major classes uniformly closer to parity and because VCFUR is recommending a significant rate reduction, rather than a rate increase, I adjusted the gradualism constraint to 160% of the overall percentage change in rates.

As can be seen on Page 1, the reduction would be constrained for the GS-1, Churches and Outdoor Lighting classes. However, all of the major classes would move approximately 25% toward parity, as defined by the Commission.

5. REAL TIME PRICING

Q IS THE CONTINUED DEVELOPMENT AND EVOLUTION OF THE COMPANY'S REAL TIME PRICING PROGRAM CONSISTENT WITH THE TRANSITION TO RETAIL CUSTOMER CHOICE?

A Yes. Real Time Pricing (RTP) is a precursor to "spot-market" pricing which is likely to occur in a fully competitive electric utility industry. Thus, RTP will help prepare both Virginia Power and its customers for competition and retail customer choice.

Q IS REAL TIME PRICING EQUIVALENT TO SPOT-MARKET PRICING?

A No. Although similar in structure, RTP is not equivalent to spot-market pricing because the hourly spot prices under RTP are based on a single generation supplier (Virginia Power, in this case). By contrast, a competitive spot-market will require the interaction of many generation sellers and many buyers, irrespective of ownership or customer type, throughout the interconnected grid. Further, Virginia Power's Schedule RTP limits the eligible load of its RTP customers to a maximum of 20% for RTP. In a fully competitive, customer choice environment, customers could choose to subject any portion, or the entirety, of their load to spot-market pricing. The customer also would be able to enter into bilateral contracts with one or more generation suppliers. Thus, Schedule RTP may provide customers with limited "virtual" direct access, but it is certainly not a substitute for customer choice.

Q SHOULD VIRGINIA POWER PROVIDE AN ADDITIONAL REAL TIME PRICING OPTION?

A Yes. The Company should be required to develop a second RTP rate schedule, in addition to the current experimental Schedule RTP. This second RTP option should be based upon "hour-ahead" pricing.

The hourly prices in Schedule RTP are presently developed on a "day-ahead" basis. Customers are provided firm hourly RTP energy charges by 5:00 p.m. on the day prior to actual consumption. Further, these prices are not subject to true-up or adjustments should the Company's actual system lambda vary from the original projection.

Although day-ahead pricing is a significant improvement over the more traditional time of use (TOU) tariffs, it is probable that the actual hourly prices will be different because day-ahead loads may be higher or lower than projected (due to ever-changing weather conditions), or generating units may be unexpectedly forced out of service. The hourly energy price also would vary significantly if the actual load in a particular hour reached or exceeded 90% of the Virginia Power adjusted annual peak load forecast, because this is when either the Generation Cost adder (GCA) or the Transmission Capacity adder (TCA) would be applicable. The end result would be dramatic change in the level of the hourly RTP prices relative to the day-ahead forecast.

Thus, the price signals under Schedule RTP could be improved dramatically if the Company were to begin offering "hour-ahead" in addition to day-ahead pricing. With hour-ahead pricing, customers still would be given day-ahead forecasts, but these hourly prices would continually be updated as conditions warrant. The price would not be firm until one hour and five minutes prior to the commencement of the hour in question. For example, a price which is applicable for the hour ending at 5:00 p.m. (4:00 p.m. to 5:00 p.m.) would become firm at 2:55 p.m. This would give customers some opportunity to adjust operations (e.g., between 2:55 p.m. and 4:00 p.m.) to respond to the pricing signal.[26] The advantage of hourly pricing, thus, is that it will provide more accurate price signals, and therefore, an opportunity for customers to respond to unexpected changes in system loads and costs on a more dynamic, real time basis.

Q WOULD A REAL TIME PRICING HOUR-AHEAD PROGRAM BE OF INTEREST TO ALL COMMERCIAL AND INDUSTRIAL CUSTOMERS?

A No. RTP may not be suitable for all customers. For example, not all customers have equal ability to respond to changing hourly prices. Even customers who are able to respond to changes in hourly prices may choose not to participate in RTP because of the added risks. For example, Schedule RTP customers may have to curtail loads to the applicable baseline levels when the Company is facing an extremely critical system operation situation. Schedule RTP customers also bear considerable price risk; that is, unlike regular tariff customer, their prices will change from hour-to-hour, and these changes immediately affect their cost of electricity.

[26]By providing continuous updates of hourly prices, Virginia Power will have given the customer advanced warning that hourly prices later in the day could change dramatically. This would give the customer an opportunity to adjust or fine tune schedules to respond to the high prices, if possible.

Both sets of risks are unique to Schedule RTP, and they are not risks that non-RTP customers are required to bear. These curtailment and price risks would be further accentuated under an hour-ahead program.

Q **ISN'T THE REAL TIME PRICING OPTION VOLUNTARY?**

A Yes. The voluntary nature of the rate, however, does not change the risks that Schedule RTP customers are required to assume. Further, some customers will be able to manage risks better than others.

Q **IS VIRGINIA POWER IN THE PROCESS OF DEVELOPING AN HOUR-AHEAD REAL TIME PRICING PROGRAM?**

A Yes. The Company is considering the design of an hour-ahead RTP program.[27] The Company cites the ability to provide a more accurate price signal as one of the objectives of an hour-ahead program. It also suggests several other objectives, such as variable GCAs and TCAs to prevent over or under-recovering marginal costs and the ability to impose curtailments during unexpected emergency events, such as the event that occurred on January 19, 1994 when the Company initiated rotating black-outs.

The Commission should require Virginia Power, within 60 days of a final order in this case, to file an application for an additional RTP schedule that is based

[27] See Virginia Power report entitled "Improved Price Signals for Each Customer Class," Case No. PUE960296.

upon hour-ahead pricing. The Company also should be encouraged to continue its efforts to develop an hour-ahead program and to be involved in this process.

Q **ARE THERE ANY OTHER RISKS UNIQUE TO SCHEDULE REAL TIME PRICING?**

A Yes. Customers that subject up to 20% of their existing loads to RTP are required to sign five-year contracts for their entire loads. In light of the increasingly rapid changes occurring in the electricity industry, a five-year commitment may be viewed as too risky by some customers. Further, the limitation that Schedule RTP loads not exceed 20% of the customer's total load may further limit opportunities for customers to utilize self-generation to displace loads that are priced under the Company's Large General Service Tariff.

For example, a non-generating customer having a 50 megawatt total load could purchase up to 10 megawatts of load under Schedule RTP. However, any significant and permanent change in electric load, such as installing base load generation to displace the remaining 40 megawatts of load being purchased under the Large General Service Tariff, would necessitate a modification to the amount of load priced under Schedule RTP. The end result could be to deter the customer from the more economical self-generation option. This provision is an impediment to self-generation. It would not be in the public interest to allow the Company to impose terms and conditions that may impede the development of competitive supply options during the transition to customer choice.

Q SHOULD ANY MODIFICATIONS BE MADE TO THE EXISTING SCHEDULE REAL TIME PRICING?

A Yes. First, Virginia Power should explore the option of expanding the current Schedule RTP to encompass more than 20% of a customer's historical load. As I discussed earlier, Schedule RTP is a precursor to spot market pricing and customer choice. An expanded Schedule RTP will further assist in the transition to customer choice. Virginia Power should, at tne conclusion of this case, file a report with the Commission on the option of expanding Schedule RTP to include greater than 20% of a customer's historical load.

Second, the Commission should order the Company to eliminate immediately the restrictions on self-generation in Schedule RTP. As I discussed above, Schedule RTP effectively restricts the construction of self-generation—by mandating the displacement of any existing RTP load. It is not in the public interest to permit Virginia Power to obstruct the development of competitive supply options in this manner.

Finally, further consideration should be made to ensure that the hourly prices accurately reflect a competitive market. Presently, the prices under Schedule RTP are based on Virginia Power's hourly system lambda. These prices are further increased by $6 per MWH and, in certain hours, by the GCA and TCA. The system lambda typically reflects the incremental cost of generation for a particular utility. To the extent that purchased power is not included in system lambda, the full effect of the increasingly competitive wholesale market is not being reflected in the hourly prices. Similarly, to the extent that Virginia Power's system is experiencing congestion, either generation or transmission, but neighboring systems are not, its hourly real time price may not accurately reflect market conditions.

Q **PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING REAL TIME PRICING.**

A The Commission should order the Company to make the following filings no later than 60 days from the Commission's final order in this case: (1) an application to implement a second RTP rate schedule based on hour-ahead pricing; and (2) an application addressing the expansion of the existing Schedule RTP to include greater than 20% of a customer's historical load.

In addition, the Commission should order the Company to remove, from existing Schedule RTP, the restrictions on the construction of self-generation. Finally, I recommend that Virginia Power be required to investigate whether its Schedule RTP prices reasonably comport with actual market conditions.

Q **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A Yes.

#415318

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is P. O. Box 412000, St. Louis, Missouri 63141-2000.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation and a principal in the firm of Brubaker & Associates, Inc., energy and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I am a graduate of Washington University. I hold the degrees of Bachelor of Science in Electrical Engineering and Master of Business Administration. At various times prior to graduation, I worked for the McDonnell Douglas Corporation in the Corporate Planning Department; Sachs Electric Company; and L. K. Comstock & Company. While at McDonnell Douglas, I analyzed the direct operating cost of commercial aircraft.

Upon graduation, in June, 1975, I joined the firm of Drazen-Brubaker & Associates, Inc. Drazen Brubaker & Associates, Inc. (DBA) was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. Brubaker & Associates, Inc. (BAI) was formed in April, 1995. In the last five years, BAI and its predecessor firm has participated in more than 700 regulatory proceeding in forty states and Canada.

During my tenure at both DBA and BAI, I have prepared numerous financial and economic studies of investor-owned, cooperative and municipal utilities, including revenue requirements, cost of service studies, rate design, site evaluations and service contracts. Recent engagements have included advising clients on electric restructuring issues, developing responses to utility requests for proposals (RFPs), and managing RFPs for clients. I am also responsible for developing and presenting seminars on electricity issues.

I have worked on various projects in over twenty states and in two Canadian provinces, and have testified before the regulatory commissions of Alabama, Arizona, Colorado, Delaware, Florida, Georgia, Illinois, Iowa, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, Ohio, Pennsylvania, Texas, Virginia and Washington. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation.

VIRGINIA ELECTRIC AND POWER COMPANY

**Illustration of the Commission's
Revenue Distribution Guidelines
Assuming a $200 Million Revenue Reduction
Test Year Ended December 31, 1996**

Line	Customer Class	Present Rate Revenue (000) (1)	Revenue Adjustment Amount (000) (2)	Revenue Adjustment Percent (3)	Index (4)
1	Residential	$1,827,133	($102,445)	-5.6%	95
2	GS-1	221,500	(20,900)	-9.4%	160
3	GS-2	572,344	(30,160)	-5.3%	90
4	GS-3	467,785	(32,310)	-6.9%	117
5	GS-4	294,134	(12,450)	-4.2%	72
6	Total Churches	6,680	(630)	-9.4%	160
7	Outdoor Lighting	11,676	(1,105)	-9.5%	161
8	Virginia Jurisdictional	$3,401,252	($200,000)	-5.9%	100

VIRGINIA ELECTRIC AND POWER COMPANY

Summary of the Class Cost of Service Study
Before and After a $200 Million Revenue Reduction
Using the Commission's Revenue Distribution Guidelines
Average and Excess Method; Fully Adjusted
Test Year Ended December 31, 1996

		Rate of Return		Index		
Line	Customer Class	Before Reduction (1)	After Reduction (2)	Before Reduction (3)	After Reduction (4)	ROR Movement (5)
1	Residential	8.40%	6.94%	93	95	24.9%
2	GS-1	12.52%	9.43%	139	129	25.5%
3	GS-2	8.85%	7.21%	98	99	25.5%
4	GS-3	10.66%	8.30%	118	114	26.1%
5	GS-4	8.51%	7.00%	94	96	24.8%
6	Total Churches	15.92%	12.50%	177	171	7.5%
7	Outdoor Lighting	12.04%	9.51%	134	130	10.6%
8	Virginia Jurisdictional	9.01%	7.31%	100	100	n/m

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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

APPLICATION OF

VIRGINIA ELECTRIC AND POWER COMPANY — CASE NO. PUE960036

1995 Annual Informational Filing

COMMONWEALTH OF VIRGINIA

At the relation of the

STATE CORPORATION COMMISSION — CASE NO. PUE960296

Ex Parte: Investigation of
Electric Utility Industry
Restructuring -- Virginia Electric
and Power Company

Direct Testimony of Kathryn E. Iverson

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A My name is Kathryn E. Iverson; 5555 DTC Parkway, Suite B-2000; Englewood, Colorado 80111.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation and employed by the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants with corporate headquarters in St. Louis, Missouri.

Q **WOULD YOU PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE?**

A I have a Bachelor of Science Degree in Agricultural Sciences and a Master of Science Degree in Economics from Colorado State University. I have been a consultant in this field since 1984, with experience in utility resource matters. More details are provided in Appendix A to this testimony.

Q **ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?**

A I am testifying on behalf of the Virginia Committee for Fair Utility Rates ("VCFUR"), who are customers of Virginia Electric and Power Company ("Virginia Power," or "Company").

Q **WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?**

A I will address the quantification of potential stranded costs as described in the Company's Transition Cost Report ("TCR").

Q **PLEASE SUMMARIZE YOUR TESTIMONY.**

A The following is a summary of my conclusions and recommedations:

(1) Any estimation of stranded costs is premature at this time. Given that critical parameters as to timing, customer choice and eligibility, market structure and other essential characteristics of a competitive retail market are unknown at this time, estimates of stranded cost should be regarded as highly speculative.

(2) Although all estimates are both premature and speculative at this time, the Company's estimate of its stranded costs is particularly flawed and excessively pessimistic. Virginia Power's hypothetical illustration of its stranded costs does not reflect a rational illustration of the value of its generating assets in a competitive marketplace.

(3) Beyond the problems inherent with any administrative determination of stranded costs, the Company's estimate also suffers from these specific flaws:

- Many of the inputs rest on questionable support or support that is impossible to substantiate, particularly with respect to the price duration curves generated from the output from the MultiSym model.

- Virginia Power has made several premature assumptions with respect to timing, market structure and extent of impending competition.

- The capacity reservation values used in its modeling of economic valuation are significantly understated. The Company has inappropriately assumed the use of an economic carrying charge rather than a levelized carrying charge, and has significantly understated the fixed operation and maintenance costs for an advanced CT. These erroneous assumptions result in an understatement of the economic valuation of the Company's generation assets, causing the estimate of stranded costs to be overstated.

- The Company has included administrative and general expenses in its valuation modeling. These types of costs may be reasonably avoidable in a competitive marketplace, and so their recovery requires no special compensation as stranded costs.

- The Company's arbitrary decision to terminate its analysis in the year 2015 results in a significant understatement of stranded *benefits*.

- Possible mitigation of NUG contracts, as well as other relevant costs associated with generation assets, has not been incorporated into the model, thereby making the Company's estimate of stranded costs a worst-case scenario.

(4) Even though any estimate of stranded cost would be premature and speculative at this time, the Company's estimate is particularly sensitive to its chosen model assumptions. Virginia Power has not fully revealed the implications of the sensitivity of its model to changes in these assumptions. In order to determine the impact of the Company's estimate of stranded costs, my testimony includes modification of the model as to capacity reservation prices and the length of valuation beyond 2015. With just these changes to Virginia Power's model, the estimate of stranded net *benefits* soars as high as $2.7 billion for the Virginia jurisdiction.

Q **HAVE YOU REVIEWED VIRGINIA POWER'S TESTIMONY ON THE ESTIMATION OF POTENTIAL STRANDED COSTS?**

A Yes. I have reviewed the TCR, Exhibit No. RER- ___ (1), which summarizes the methodology the Company developed to assess the magnitude of its potential transition costs, along with its presentation of "illustrative transition costs based on a given set of hypothetical assumptions."[1] The estimates of hypothetical transition cost exposure are based on a series of Company models that quantify the value of Virginia Power's existing portfolio of generation assets assuming that these same resources would operate in what the Company has characterized as a competitive generation market. The portfolio includes existing fossil, hydro and nuclear assets and NUG contracts. The economic value of these resources is then compared to their regulatory net book value to determine the potential exposure to transition costs. The Company proposes that an actual determination would be made when retail competition is authorized.[2]

Q **WHAT ESTIMATE OF STRANDED COSTS DOES THE COMPANY PROVIDE IN ITS REPORT?**

A Based on its analysis, the Company estimates total system-wide stranded costs of $3.2 billion. The vast majority ($3 billion) of these potential stranded costs relate to above-market NUG contracts. Fossil and hydro assets would provide *stranded benefits* of over $600 million that is, the assets are worth more in a competitive marketplace than the amount shown on the Company's books for those units. Nuclear assets would result in transition costs of $789 million, so that the subtotal of all generation would be an overall transition cost of $188 million.

Q **HOW DO THE COMPANY'S INDIVIDUAL HYDRO AND FOSSIL GENERATING UNITS CONTRIBUTE TO THE $600 MILLION OF STRANDED BENEFITS?**

A Exhibit ___ (KI-1), Schedule 1 details the Company's estimate of stranded benefits on a plant-by-plant basis. * * * * * ALLEGED COMMERCIALLY SENSITIVE

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[1]TCR, Page 1, Line 12.

[2]Testimony of Robert Rigsby, page 48.

INFORMATION DELETED * * * * * * * * * * * * * ALLEGED COMMERCIALLY SENSITIVE INFORMATION DELETED * * * * * * * * ALLEGED COMMERCIALLY SENSITIVE INFORMATION DELETED * * * *. Of all the fossil units, Clover Power Station Units #1 and #2 have * * * * * * * **ALLEGED COMMERCIALLY SENSITIVE INFORMATION DELETED** * * * * * * *. North Branch is * * * **ALLEGED COMMERCIALLY SENSITIVE INFORMATION DELETED** * * * * * and Bremo Power Station Units #3 and #4 have a total of * * * * * *. In the case of Chesapeake Power Station, Units #1 and #2 exhibit * * * * * * * * * * * **ALLEGED COMMERCIALLY SENSITIVE INFORMATION DELETED * * * * * * * * * * * ALLEGED COMMERCIALLY SENSITIVE INFORMATION DELETED * * * * * * * * * * * ALLEGED COMMERCIALLY SENSITIVE INFORMATION DELETED * * * * * * * * * * * ALLEGED COMMERCIALLY SENSITIVE INFORMATION DELETED * * * * * * * * * * * ALLEGED COMMERCIALLY SENSITIVE INFORMATION DELETED * * * * * * * * * * * ALLEGED COMMERCIALLY SENSITIVE INFORMATION DELETED..**

Bath County Pumped Storage shows * * * * * * while Cushaw has * * * * * * * * * * *. The other hydro facilities * * * * * **ALLEGED COMMERCIALLY SENSITIVE INFORMATION DELETED** * * * * *.[3]

Q YOU MENTIONED THAT * * * * * * * * HAS A SMALL NEGATIVE FREE CASH FLOW. PLEASE DEFINE THE TERM FREE CASH FLOW.

[3]Upon review of the Company's supporting workpapers, it appears the capacity-related revenues for the Roanoke Rapids Hydro Station units were inadvertently omitted. Although the model includes capacity prices and shows a maximum deliverable capacity of * * * * * * * *, the cells for capacity revenue are all $0. Correcting this oversight results in the total transition benefit of fossil and hydro increasing to $618 million, rather than $601 million.

A This term describes revenues less expenses (including taxes), with adjustments for non-cash items such as depreciation and non-cash overhead. Capital expenditures and increases in working capital also are removed from the estimate, so that free cash flow provides the expected revenue free and clear of all expenses associated with operating the resource. The stream of free cash flows is discounted and accumulated to derive the asset value of the resource. ****** **ALLEGED COMMERCIALLY SENSITIVE INFORMATION DELETED** ****** **ALLEGED COMMERCIALLY SENSTIIVE INFORMATION DELETED** ***** **ALLEGED COMMERCIALLY SENSITIVE INFORMATION DELETED** ****** .

Assumptions Used In Virginia Power's
<u>Estimates of Stranded Costs</u>

Q **WHAT TYPES OF ASSUMPTIONS WERE MADE TO ARRIVE AT THE HYPOTHETICAL SYSTEM STRANDED COST EXPOSURE OF $3.2 BILLION?**

A The stranded cost estimate is premised on models with assumptions as to: (1) future market clearing prices for energy, (2) future capacity reservation prices, (3) the expected operation of each Company generation unit, (4) the forecasted costs to operate each generation unit, and (5) a specific time frame for analysis.

Q **HOW WERE ENERGY PRICES DEVELOPED?**

A Market clearing prices for energy were based on both utility and multi-regional data. A computer model, known as MultiSym developed by Henwood Energy Services, Inc., was used to simulate the Virginia Power system and 22 neighboring interconnected transmission areas including AEP to the west, PJM utilities to the north, and Florida utilities, Southern Company and TVA to the south. The MultiSym model did not generate electricity prices; instead, it generated the hourly marginal costs for each modeled transmission area for the region for the years 1997 through 2005. Prices for the period 2006 through 2012 were developed by escalating portions of the 2005 price duration curve by rates of 2.5% to 5.0%[4]. The post-2012 energy prices were escalated at 3.4% per year.[5] Virginia Power provided the following description of the results of MultiSym:

> Marginal costs can be interpreted as the prices at which the market clears in each area. These are therefore "spot" prices at which energy may be bought or sold in the simulated markets. The model does not explicitly forecast market prices ..[6]

In summary, MultiSym generated a distribution of hourly marginal costs over the year. These expected values of marginal costs then were converted to average energy prices and plotted as a function of cumulative hours (or probability) in the price duration curve. Energy prices then were separately verified by prices from a second model developed by IREMM, Inc.

Q WHAT IS A PRICE DURATION CURVE?

A Similar to a load duration curve, a price duration curve provides a summary of the average prices over the year. With hours (or cumulative probability) shown on the x-axis, and average price on the y-axis, a price duration curve provides the number of hours (or probability) that a price will be greater than y cents per kWh. For example, Exhibit ____ (KI-1), Schedule 2, is in the Company's price duration curve for 2003. It shows that, on average, market prices will be greater than $24 per MWh 100% of the time, but that prices will be greater than $30 per MWh only 52% of the time. For a

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[4]Virginia Power Response to Question No. 383 included in the Thirteenth Set of Interrogatories from the Office of the Attorney General.

[5]Virginia Power Response to Question No. 13 included in the Sixth Set of Interrogatories from VCFUR.

[6]Virginia Power Response to Question No. 68 included in the Third Set of Interrogatories from the Virginia Independent Power Producers.

smaller time of the year, say 10%, prices will be much higher: e.g., in 2003, prices will be greater than $51.40 per MWh only 10% of the time.

Q WHAT DATA IS REQUIRED TO CONSTRUCT A PRICE DURATION CURVE?

A Two items are necessary: marginal costs and expected hours (or probability). Referring to Page 2 of Exhibit ___ (KI-1), Schedule 2, marginal costs are first ranked in increasing order, along with their respective hours and probabilities of occurrence. As marginal costs increase, there is a corresponding decline in the cumulative probabilities of marginal cost exceeding a given amount. The decline in cumulative probability is shown in Column (4). Each marginal cost is weighted by its probability, and the weighted marginal costs are shown in Column (6). These expected values for marginal costs are summed [Column (7)] and then divided by the expected cumulative probability to derive the average price [Column (8)]. The average prices then are plotted as a function of cumulative probability, as shown on the graph on page 1 of Schedule 2.

Q HOW WERE THE PRICE DURATION CURVES USED TO QUANTIFY STRANDED COSTS?

A These annual price duration curves were used in two ways in the Company's modeling of stranded costs: (1) to estimate each unit's capacity factor, and (2) to estimate average energy revenue for each unit. First, these annual price duration curves were used to determine the expected annual capacity factors for each of the Company's generation resources as a function of each unit's annual variable operating cost.[7] For example, if a unit were forecasted to have a dispatch cost (or variable running cost) of

[7]There were certain exceptions to the use of price duration curves to determine expected annual capacity factors. Capacity factor was independently assigned to the nuclear generation (85%), to Bath County Pumped Storage (30%), and in situations where plants did not recover their variable costs, and so had 0% capacity factor.

$20 per MWh in 2003, and if the price duration curve for 2003 showed that marginal costs would exceed $20 per MWh 43.8% of the time in the year, then the unit's capacity factor would be set at 43.8%.

The second use of the price duration curve was to determine the weighted average price to be paid for energy generated by each unit. Again, using 2003 as an example, a unit with variable costs of $20 per MWh would receive prices that average $31.46 per MWh.

Q HOW WERE CAPACITY VALUES DERIVED?

A Capacity values incorporated in the Company's models are premised on the annual economic carrying charges for an advanced combustion turbine (CT), less an expected contribution to fixed costs from the value of its energy generation. An escalation of 3% per year was used to extrapolate prices past 2012.[8]

Q WHAT OTHER ASSUMPTIONS ARE RELEVANT TO THE COMPANY'S ESTIMATE OF TRANSITION COSTS?

A Assumptions as to expenses, such as fuel, operation and maintenance (O&M), administrative and general (A&G), overhead, depreciation, insurance and other taxes were also forecasted and either assigned or allocated to each generating unit. Finally, assumptions regarding the timing and extent of competition, length of analysis, and the applicable discount rate were made in order to develop the economic valuation of the assets.

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[8]Virginia Power Response to Question No. 13 included in the Sixth Set of Interrogatories from VCFUR.

Q **WHAT DOES VIRGINIA POWER'S ESTIMATE OF TRANSITION COSTS ILLUSTRATE?**

A The Company's modeling of its generation assets illustrates an administrative approach to determining an estimate of value. By its very nature, an administrative determination of stranded costs requires a wide range of assumptions as to the going forward expenses to operate the units. More importantly, though, it requires an administratively determined market price to be used in the revenue pcrtion of the model. Although the cash flow analysis described by the Company is generally consistent with the way assets would be valued in a competitive market, there are, nonetheless, serious flaws inherent in any administrative determination of future costs. In fact, these types of forecasting follies for avoided costs led to the Company's current estimates of massive stranded costs associated with the NUG contracts. As Mr. Pollock testifies, administrative determinations of transition costs are necessarily judgmental, and are critically dependent on expected levels of competitive market prices for electricity and future operating costs of existing generation assets. Beyond these obvious problems inherent with any administrative determination of stranded costs, the Company's estimate also suffers from more specific flaws.

Q **WHAT FLAWS OR PROBLEMS DO YOU SEE WITH THE COMPANY'S METHODOLOGY FOR ESTIMATING TRANSITION COSTS?**

A Many of the inputs to the Company's estimate rest on questionable support or support that is impossible to substantiate, particularly with respect to the price duration curves generated from the output from the MultiSym model. The Company's model also suffers from flaws related to the following: (1) premature assumptions, (2) understated capacity values, (3) inclusion of administration and overhead costs, (4) an arbitrary cutoff date for the analysis as to the remaining lives of the generating units, and (5) an assumption that no mitigation of NUG costs would occur. Making adjustments for only two of these flaws (capacity reservation prices and extending the valuation analysis) can raise the fossil and hydro stranded *benefit* to over $2 billion.

Marginal Costs As A Basis For
<u>Projecting Electricity Prices</u>

Q YOU HAVE TESTIFIED THAT THE MULTISYM MODEL WAS USED TO ESTABLISH MARGINAL COSTS, WHICH IN TURN WERE USED TO DETERMINE THE COMPANY'S PRICE DURATION CURVES. WHY HAS VIRGINIA POWER USED MARGINAL COSTS TO PROJECT FUTURE ELECTRICITY PRICES?

A The general basis for using marginal costs stems from the assumption that under perfect competition, prices would be driven to marginal cost if there are many producers and consumers. That is, no one producer would be capable of influencing the market to cause the price to reach an artificially high level because alternative suppliers, seeing potential profit to be made, would enter the market, provide additional supply, and eventually push price toward marginal cost. There are several necessary conditions in order for price to equal marginal cost. There must be: (1) many buyers and sellers, (2) a standard (homogeneous) product, (3) perfect information, and (4) no barriers to entry in the marketplace.

Q DO THESE MARGINAL COSTS INCLUDE ANY PROFIT, OR CONTRIBUTION FOR RECOVERY OF CAPITAL?

A No. Whether one calls these marginal costs, "spot prices," "market clearing prices" or "incremental costs," the prices strictly reflect variable costs, such as fuel, operation and maintenance, wheeling, and losses. No profit is directly included in the spot price. Any contribution to fixed costs stems from the unit being dispatched at times when the spot price is greater than its variable operating costs.

Q **HAVE YOU BEEN ABLE TO REVIEW THOROUGHLY ALL THE INPUTS USED IN THE MULTISYM MODEL USED TO GENERATE THESE MARGINAL COSTS?**

A No. The MultiSym model is a complex simulation model "black box." Although we were not able to scrutinize the input to the model, we were able to analyze the results of the model, that is, the price duration curves.

Q **WHAT HAVE YOU FOUND IN REVIEWING THE MARKET CLEARING PRICES GENERATED BY MULTISYM?**

A The MultiSym model actually was used only for projecting market clearing prices for the years 1997 through 2005. The results from the 2005 analysis were segregated by probability and escalated at various rates to generate price duration curves for the years 2006 through 2012. For years beyond 2012, prices were escalated at 3.4%. Consequently, Virginia Power's direct use of MultiSym in its stranded cost estimate is limited to energy prices in four years (2002 through 2005), with extrapolations for each of the following years.

Exhibit ___ (KI-1), Schedule 3, graphically shows the trends associated with four specific variable running (dispatch) costs: $17, $20, $25 and $30 per MWh.[9] For the actual MultiSym model simulations in years 1997 through 2005, the average price of energy actually *decreases* for most dispatch costs. For example, a unit with a low dispatch cost of $17 per MWh would receive an average weighted price of $25 per MWh in 1997, dropping over the years 1998 through 2003 and then increasing to a level above $25 per MWh in years 2004 and 2005 for an overall annual increase of 0.9%. Units with dispatch costs of $20, $25 and $30 per MWh would all receive

[9]The term dispatch cost and variable running costs are used interchangeably. In the Company's model, variable running costs include expenses for fuel, variable O&M and SO_2 emissions.

declining energy prices of 1.2%, 1.4% and 1.9% respectively, even though their dispatch costs were constant. The 2005 price duration curve served as the foundation for all the remaining price duration curves used in the estimation of transition costs.

Q DO THESE MARGINAL COSTS PROVIDE A REASONABLE FORECAST FOR PRICES IN A COMPETITIVE MARKETPLACE?

A That is simply unknown at this time. We do know that energy prices based strictly on marginal costs require the acceptance of several critical assumptions as to market structure, the universe of suppliers, and spot pricing inputs. First, a market price based on spot prices assumes <u>all</u> <u>suppliers</u>, or over 1,100 regional generation units, selling <u>all</u> <u>their</u> <u>output</u> into a single clearinghouse, and <u>all</u> <u>receiving</u> the same spot price at any time based on the marginal unit on-line. Whether or not this type of market structure (generally referred to as PoolCo) will develop for retail access is not known today. Second, it assumes perfect competition, with no supplier exhibiting market power, no barriers to entry for competitors to enter the market, full information and all suppliers providing a homogenous product. Only under all these conditions would competitive prices approach marginal costs at all times. Third, these spot prices are a function of all the inputs into the MultiSym model, such as projections of load growth and capacity expansion, fuel costs, wheeling charges, transmission constraints, etc. Fuel forecasts alone used in the MultiSym represent costs of over 1,100 generating resources owned by over 40 utilities and independent power producers. Any deviation in initial fuel price levels, fuel price escalations, heat rates, variable O&M expenses, or load forecasts presumably would alter the result from MultiSym.

Finally, the MultiSym model totally ignores the value or cost associated with ancillary services. In a competitive environment, the value of this resource will be an important consideration in the total price of delivered generation.

Critical Assumptions as to Timing, Structure
And Extent of Competition Are Premature

Q HOW DOES VIRGINIA POWER INCORPORATE CRITICAL ASSUMPTIONS AS TO STRUCTURE AND TIMING OF COMPETITION IN ITS MODELS?

A Virginia Power has made several premature assumptions with respect to timing, structure and extent of impending competition. The Company has selected one specific date certain (1/1/2003) to model its estimate of transition costs. The choice of this date influences the going-forward stream of revenues generated by its assets, because any and all economic valuation in the Company's model is based on competitive prices commencing in the year 2002. Delaying, or phasing in, retail access has not been modeled by the Company.[10]

Second, as previously discussed, the Company has presumed a specific market structure for competition that directly impacts the estimate of revenues for its product. In its base case estimation, the net present value of energy-related revenues comprises * * * * * **ALLEGED COMMERCIALLY SENSITIVE INFORMATION DELETED** * * * , with capacity revenues at * * * * * * * and ash marketing at * * * * * * * * * * * * * *. All energy-related revenues are solely the result of market-clearing marginal costs, or "spot prices." Under a PoolCo form of market structure, all buyers and sellers must make transactions through a centralized clearinghouse. However, the market structure that will develop with retail access is not known and measurable today. Consequently, the Company's fundamental basis for over 80% of the assumed revenues in its modeling hinges on this one highly uncertain assumption.

[10]The results of the Company's model show estimated transition costs for years post 2003 (Virginia Power's Response to Question No. 121 included in the First Set of Interrogatories from the Staff). However, as explained later, all these estimates assume a cut-off date of 2015 for economic valuation.

Third, the Company's model is a "flash-cut" to competition whereby all customers immediately switch to direct access, making this estimate of transition costs the worst-case scenario. A more likely scenario would be that customers moving to choice would proceed more slowly, without an instantaneous conversion of each and every customer on day one of competition. Under this more likely scenario, Virginia Power would continue to recover its fully allocated costs through traditional bundled rates for provision of service to "full-requirements" customers. This would reduce transition costs.

Capacity Reservation Values Are
<u>Understated in Company's Model</u>

Q WHAT CAPACITY VALUES DOES THE COMPANY USE IN ITS MODELS?

A In its base case scenario, Virginia Power uses capacity values of $24.48 per kW-year in 2003, escalating at roughly 2% from 2003 through 2006, and at 3% thereafter. The upper bound for capacity value is around 10% higher at $27.12 per kW-year in 2003, also escalating at around 3%.

Q ARE THESE REASONABLE ESTIMATES FOR THE VALUE OF CAPACITY IN DETERMINING TRANSITION COSTS?

A No, they are not. Through a combination of erroneous assumptions, the Company has greatly understated capacity reservation values used in its modeling of transition costs.

Q HOW HAS THE COMPANY UNDERSTATED CAPACITY VALUE?

A First, the Company has inappropriately assumed the use of an *economic* carrying charge rather than levelized carrying charge.

Q **WHAT IS A "CARRYING CHARGE"?**

A The total capacity cost for a CT must be adjusted by a carrying charge in order to put the total costs on an annual basis. Virginia Power uses an economic carrying charge for determining the annual cost of a CT. An economic carrying charge measures the value of deferring CT capacity, or "delaying the installation of the facility by one year."[11] It recognizes only a one-year deferral of capacity costs, and thus provides a short-sighted value of capacity. The Company's myopic valuation of capacity reservation prices does not reflect prices available under a long-term contract; it reflects only an annual commitment.[12]

Q **WHY DOES THE COMPANY BELIEVE ITS METHOD OF USING AN ECONOMIC CARRYING CHARGE IS APPROPRIATE?**

A Virginia Power bases its use of an economic carrying charge on the replacement cost perspective:

> The appropriateness of this method derives from its replacement cost perspective; that is, it would appear reasonable that a buyer would not be willing to pay more for capacity in a given year than the cost that would be avoided by deferring the construction of the facility for that year.[13]

Q **DO YOU AGREE THAT "REPLACEMENT COST" IS THE CORRECT PERSPECTIVE FOR VALUING CAPACITY IN A COMPETITIVE MARKET?**

A No. The replacement cost perspective assumes that a seller of capacity would only recover the costs for its product several years out in the future. This wrongly assumes

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[11]Virginia Power Response to Question No. 34 included in the Sixth Set of Interrogatories from VCFUR.

[12]Virginia Power Response to Question No. 386 included in the Thirteenth Set of Interrogatories from the Office of the Attorney General.

[13]Virginia Power Response to Question No. 34 included in the Sixth Set of Interrogatories from VCFUR.

that future generators will be able to finance projects even though payments would be significantly back-end loaded. For example, Exhibit ___ (KI-1), Schedule 4, provides a simple hypothetical comparing a stream of payments under an economic carrying charge stream of revenues versus the more traditional levelized approach. From the seller's perspective, a payment stream based on an economic carrying charge would provide insufficient dollars to pay off any principal whatsoever for 19 years -- that is, the unpaid balance exceeds the original principal through year 19. A nominally levelized revenue stream, on the other hand, consistently provides sufficient revenue each year to pay off interest charges and make a contribution to reducing principal. Virginia Power's assumption focuses on buyers unwilling to pay a price higher than the amount associated with a one-year deferral. This ignores the other side of the transaction -- sellers would be unwilling to sell at a price that delays recovery of their costs for such a long period of time. Virginia Power's use of an economic carrying charge understates the market value of capacity.

Q **BESIDES USING AN ECONOMIC CARRYING CHARGE, HAS THE COMPANY UNDERSTATED THE MARKET VALUE OF CAPACITY IN ANOTHER WAY?**

A Yes. Virginia Power has significantly understated the fixed O&M costs for its assumed advanced CT. The Company uses a fixed O&M cost of only $1.56 per kW-year in 1997 in the development of its all-in costs for a CT, with no substantiation or supporting documentation. In contrast to the Company's estimated cost, the Energy Information Administration estimates that annual fixed O&M for advanced combustion turbines would be more in the neighborhood of $17.20 per kW,[14] more than ten times the amount used in the Company's calculations. Thus, as a result of a combination of errors, the Company has significantly understated the expected value of capacity.

[14]"Assumption for the *Annual Energy Outlook 1997*," Energy Information Administration, December 1996, p. 58.

Q IS THE COMPANY AWARE OF ANY RECENT LONG-TERM FIRM POWER TRANSACTIONS THAT PROVIDE FOR CAPACITY AND ENERGY AT ITS FORECASTED PRICES?

A No. According to the Company's response, Virginia Power is not aware of any long-term (i.e., greater than three years) transactions at prices comparable to the market clearing prices and capacity reservation values shown in Figure 1 on Page 16 of the TCR.[15] Again, this leads us to question the reasonableness of both the Company's assumed energy and capacity values.

Q HAVE YOU QUANTIFIED A MORE REASONABLE ALL-IN COST OF FUTURE GENERATION CAPACITY ADDITIONS?

A Yes. This is shown in Exhibit ___(KI-1), Schedule 5, Page 1, Column (5).

Q HOW DOES THE ALL-IN COST OF NEW GENERATION CAPACITY COMPARE WITH VIRGINIA POWER'S ESTIMATED MARKET PRICES?

A The Company's projected market prices shown on Page 1 in Column (2) of this Schedule are considerably below the all-in cost of new capacity that I have calculated.

Q VIRGINIA POWER CLAIMS THAT "ENERGY AND CAPACITY PRICES INCREASE TO LEVELS THAT SUPPORT THE CONSTRUCTION OF ADDITIONAL PEAKING CAPACITY" DURING THE PERIOD FROM 2000 THROUGH 2005. DO YOU AGREE?

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[15]Virginia Power Response to Question No. 387 of the Thirteenth Set of Interrogatories from the Office of the Attorney General.

A No. The Company's energy prices and capacity reservation prices would not support construction of additional peaking capacity. In 2005, according to the Company's price duration curves, the average weighted price provides a contribution of only $12 per kW annually. This contribution, together with its forecasted base capacity reservation price of $2.12 per month, would provide only $38 per kW annually, an amount that would not cover the total all-in costs of $65 per kW in 2005.

Q **HAVE YOU DEVELOPED AN ESTIMATE OF A MORE APPROPRIATE CAPACITY RESERVATION VALUE FOR USE IN ESTIMATING TRANSITION COSTS?**

A Yes. Using construction costs of $300 per kW (in 1997 dollars), O&M costs based on the recent EIA information, and nominal levelization, a more realistic base net capacity cost would be around $50 per kW-year in the year 2002. This amount has been adjusted for the expected contribution to fixed costs from the value of its energy generation based on a 5% capacity factor. As shown in Column (6) of Schedule 5, the capacity margin provided through energy-related revenues averages close to $13 per kW-year for the years 2003 through 2006. Without this expected contribution to fixed costs, the capacity value would be higher by that amount.

The Company's Modeling Of Costs Should Not Include
<u>Continuing Levels of Administrative and General Overhead</u>

Q **WHAT TYPES OF COSTS ARE INCLUDED IN THE COMPANY'S PROJECTIONS FOR EACH GENERATING UNIT?**

A In addition to typical on-going costs for fuel, planned outages, routine maintenance and operations, taxes, insurance, SO_2 emissions, etc., the Company has included general administrative costs and benefits. Only when market clearing prices rise to sufficient levels to cover these costs will these costs be recoverable in the competitive marketplace. Although these expenses are not as large as say, fuel expenses, they still impact the overall discounted free cash flow.

Q ARE THESE TYPES OF COSTS RECOVERED BY UTILITIES THROUGH TRADITIONAL REGULATION?

A Yes, for the most part, they are. Under the present cost of service form of regulation, a utility's costs drive rates. If a utility incurs increased costs, it can petition the Commission for a rate increase. In a competitive environment, this would no longer be the case; electricity prices would be market-determined. A utility's return will depend much more on its ability to control costs successfully. If a supplier's costs are out of line in a competitive environment, the supplier will find it necessary to control its costs rather than seek additional revenues for relief. The Company's model escalates administrative costs at 3.5% annually, and system benefits at 5%. A firm facing rising costs and low prices for its output would search for any and all ways to reduce its costs down to a level commensurate with the market.

Q ARE A&G COSTS UNMITIGATABLE OR UNAVOIDABLE?

A No. Some of these expenses are under the control of the resource operator, and thus should not be accepted as unmitigatable or unavoidable. To the extent that average energy prices in the competitive market are not sufficient to justify high levels of administrative and general expenses, a competitive supplier would need to bring them under control, or it would need to cease operations.

Q IS IT APPROPRIATE TO INCLUDE A&G COSTS IN VALUING VIRGINIA POWER'S GENERATION ASSETS?

A No. As Mr. Pollock testifies, no special compensation is necessary or appropriate if a utility has a reasonable opportunity either to mitigate or avoid a potentially strandable cost, such as future administrative and general expenses. The inclusion of Virginia Power's on-going levels of A&G costs in its asset valuation effectively lowers its free cash flow, and correspondingly raises the level of stranded costs.

Stranded Benefits are Greatly Understated As A
<u>Result Of Arbitrarily Ending the Economic Valuation</u>

Q FOR WHAT TIME PERIOD DID THE COMPANY EVALUATE ITS GENERATION ASSETS?

A In its models, Virginia Power determined the economic valuation of each generating unit from 2002 through 2015. The NPV of discounted free cash flows at year end 2002 was compared to each unit's net book value as of 2002 to determine its exposure to transition costs.

Q WHY DID THE COMPANY CHOOSE THE YEAR 2015 AS THE ENDING POINT OF ITS ANALYSIS?

A According to the Company, 2015 is the year "... in which all of the Company's owned and contracted generation resources in total are expected to clear the market." [16]

Q IS THIS AN APPROPRIATE DATE TO END THE ANALYSIS?

A No, it is not. The year 2015 marks only the beginning of the period in which the Company's generating units will make a profit above market-clearing prices. By artificially ending the analysis at 2015, Virginia Power has sent a strong signal to its customers and the Commission that the Company is more concerned about the *costs* competition will place on the utility, than the *benefits* it will receive through a competitive marketplace. Once market clearing prices are sufficient to enable the

[16]TCR, Page 9, Line 1.

Company to sell its generation into the market for a profit, the Company will start to benefit from competition. However, the transition cost analysis focuses only on the initial years, when the Company's generation is relatively costly in comparison to the market. It is as if Virginia Power proposes to ignore completely the reality that its generating assets will be *operational*, as well as *profitable*, in the years after 2015. The Company's proposal to ignore the later benefits of competition, while exclusively focusing on near-term potential costs, should be rejected. The ability to earn returns not capped under regulation is one of the upside benefits of retail competition for current providers of generation services, like Virginia Power.

The Company's Model Includes No Mitigation Of Costs, Particularly Those Associated With NUG Contracts

Q THE COMPANY HAS INDICATED THAT NUG CONTRACTS COMPRISE OVER $3 BILLION OF ITS ESTIMATED STRANDED COSTS. HAS THE COMPANY FULLY MITIGATED THE COSTS ASSOCIATED WITH THESE CONTRACTS?

A The answer to this question is unknown at this time. It is my understanding that Virginia Power is presently engaged in negotiations with its NUG suppliers to lessen the impact of these contracts on future expenses. The outcome of these contract negotiations is in doubt and is unlikely to be fully resolved by the conclusion of this proceeding. It is my understanding that the $3 billion estimate of stranded NUG costs does not include any forecast of mitigation that may result from these on-going negotiations, making the Company's estimate of its stranded costs a worst-case scenario.

Mitigation of costs associated with its owned generating assets also is unknown at this time. Without a complete benchmarking of its generation, there is no clear indication that any mitigation has been incorporated in the administratively determined estimate of transition costs included in the Company's TCR.

As an example of mitigatable costs, Virginia Power has included in its estimate of stranded costs $945,000 for the cost of land for a future generating station site (Ahoskie).[17] The Company includes only revenues associated with sales of energy, capacity and ash: no attempt has been made to place a value on land in its modeling of asset valuation in a competitive marketplace. Thus, Virginia Power's modeling of stranded costs effectively labels land costs as 100% potentially stranded. It is reasonable to assume these strategically valuable generation sites would have a value in the competitive market. As with future administrative and general expenses, the utility has a reasonable opportunity to mitigate this cost (e.g., selling or leasing the land), so consequently no special compensation for land costs is necessary.

Estimated Change in Potential Stranded
<u>Costs With More Appropriate Assumptions</u>

Q HAVE YOU ASSESSED THE IMPACT ON THE COMPANY'S STRANDED COST ESTIMATE OF USING ANY ALTERNATIVE ASSUMPTIONS?

A Yes. In order to determine the impact of two key assumptions underlying the Company's estimate of stranded costs, I have modified the Company's analysis to include more reasonable capacity reservation prices and to extend the evaluation beyond 2015. I adjusted these two elements of the Company's estimates of transition costs to show just how sensitive the results of the analysis are to only these two assumptions. I have not made any adjustment to the other assumptions, such as energy price forecasts, administrative costs, or assumed mitigation levels, so this should not be construed as an endorsement of, or an alternative to, the Company's analysis.

[17]Virginia Power Response to Question No. 8 included in the Thirteenth Set of Interrogatories from the VCFUR.

Schedule 6 details the results of changing just these two assumptions under various scenarios. Page 1 shows the results of changing these two assumptions separately, by individual adjustments to the estimated transition costs, while page 2 shows the cumulative effects of these adjustments. The following explanation tracks each Column of this Schedule:

Column (1): This column displays the estimate of fossil, hydro, nuclear and NUG transition costs as calculated by Virginia Power in its TCR.[18]

Column (2): This column corrects for the omission of capacity revenues for Roanoke Rapids Hydro.

Column (3): This column incorporates the results of a more appropriate capacity reservation value.

Column (4): This column shows the results of extending the analysis beyond 2015 using the Company's capacity reservation prices.

Column (5): This column incorporates the revised capacity costs for the years 2016 through 2025.

Column (6): This column extends the analysis from 2025 to 2035, using the Company's capacity reservation prices.

Capacity (7): This column incorporates the revised capacity costs for the years 2026 through 2035.

The cumulative impacts of these individual adjustments are shown on Page 2 of Schedule 6. For example, extension of the analysis through the year 2035 together with revised capacity reservation prices results in a total net stranded *benefit* for the Virginia jurisdiction of over $2.7 billion.

Q WHAT CONCLUSIONS DO YOU DRAW BASED UPON YOUR EVALUATION AND ADJUSTMENTS TO VIRGINIA POWER'S ESTIMATE OF TRANSITION COSTS?

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[18]The Company recently has detected an error in its estimate of transition costs for the Lakeridge facility (Virginia Power Response to Question No. 7 included in the Thirteenth Set of Interrogatories from VCFUR). This correction is not included in Schedule 6.

A As the Company has recognized, any estimate of stranded costs depends on the assumptions used in the modeling. For example, the time period analyzed greatly influences the estimate. The Company's decision to terminate its analysis at 2015 results in a significant overstatement of potential stranded costs. In addition, a more appropriate level of capacity reservation prices also reduces the Company's estimated stranded costs.

Although other important assumptions made by Virginia Power cannot be quantified as readily in the modeling of transition costs, their importance to the overall estimate should not be overlooked. Virginia Power's assumption as to a PoolCo-type of market for the development of price duration curves and the flash-cut to competition are also important contributors to any estimated transition costs developed with this type of cash flow model. Should a different type of market structure eventually emerge, or should customer choice be phased-in, estimates of potential stranded costs based on the Company's models and assumptions would not be representative. In any event, any estimate of stranded costs is premature and speculative at this time.

Q **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A Yes, it does.

#414826

Qualifications of Kathryn E. Iverson

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Kathryn E. Iverson; 5555 DTC Parkway, Suite B-2000; Englewood, Colorado 80111.

Q **PLEASE STATE YOUR OCCUPATION.**

A I am a consultant in the field of public utility regulation with Brubaker & Associates, Inc., regulatory and economic consultants.

Q **PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.**

A In 1980 I received a Bachelors of Science Degree in Agricultural Sciences from Colorado State University, and in 1983, I received a Masters of Science Degree in Economics from Colorado State University.

In March of 1984, I accepted a position as Rate Analyst with the consulting firm Browne, Bortz and Coddington in Denver, Colorado. My duties included evaluation of proposed utility projects, benefit-cost analysis of resource decisions, cost of service studies and rate design, and analyses of transmission and substation equipment purchases.

In February 1986, I accepted a position with Applied Economics Group, where I was responsible for utility economic analysis including cogeneration projects, computer modeling of power requirements for an industrial pumping facility, and revenue impacts associated with various proposed utility tariffs. In January of 1989, I was promoted to the position of Vice President. In this position, I assumed the additional responsibilities of project leader on projects, including the analysis of alternative cost recovery methods, pricing, rate design and DSM adjustment clauses, and representation of a group of industrial customers on the Conservation and Least Cost Planning Advisory Committee to Montana Power Company.

In March 1992, I accepted a position with ERG International Consultants, Inc., of Golden, Colorado as Senior Utility Economist. While at ERG, I was responsible for the cost-effectiveness analysis of demand-side programs for Western Area Power Administration customers. I also assisted in the development of a reference manual on the process of Integrated Resource Planning including integration of supply and demand resource, public participation, implementation of the resource plan and elements of writing a plan. I lectured and provided instructional materials on the key concept of life-cycle costing seminars held to provide resource planners and utility decision-makers with a background and basic understanding of the fundamental techniques of economic analysis. My work also included the evaluation of a marginal cost of service study, assessment of avoided cost rates, and computer modeling relating engineering simulation models to weather-normalized loads of schools in California.

In November of 1994, I accepted a position with Drazen-Brubaker & Associates, Inc. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and Staff. Since joining this firm, I have performed various analyses of integrated resource plans, examination of cost of service studies and rate design, as well as estimates of transition costs and restructuring plans.

Q **HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?**

A Yes. I have testified before the regulatory commissions in Colorado, Georgia, Michigan, Montana, Texas and Wyoming.

Exhibit ___ (KI-1)
Schedule 1
Page 1 of 3

VIRGINIA ELECTRIC AND POWER COMPANY

Summary of Company Estimates of Economic Value, Net Book Value and Transition Cost of Fossil/Hydro Units (Thousands of Dollars)

	Description	Asset Value In a Competitive Market (1)	Regulatory Net Book Value (2)	Transition Cost (3)	Adjusted to Revenue Requirements (4)
	FOSSIL PLANTS:				
1	Bremo Power Station				
2	Unit #3				
3	Unit #4				
4	Subtotal				
5	Chesapeake Power Station				
6	Unit #1				
7	Unit #2				
8	Unit #3				
9	Unit #4				
10	Chesapeake CT				
11	Kitty Hawk				
12	Gravel Neck				
13	Subtotal				
14	Chesterfield Power Station				
15	Unit #3				
16	Unit #4				
17	Unit #5				
18	Unit #6				
19	Unit #7				
20	Unit #8				
21	Subtotal				
22	Clover Power Station				
23	Unit #1				
24	Unit #2				
25	Subtotal				
26	North Branch Power Station				
27	Unit #1				
28	Subtotal				
29	Possum Point Station				
30	Unit #1				
31	Unit #2				
32	Unit #3				
33	Unit #4				
34	Unit #5				
35	Possum CT				
36	Darbytown				
37	Lowmoor				
38	Northern Neck				
39	Subtotal				

ALLEGED COMMERCIALLY SENSITIVE INFORMATION DELETED ***************

ALLEGED COMMERCIALLY SENSITIVE INFORMATION DELETED ***************

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VIRGINIA ELECTRIC AND POWER COMPANY

Summary of Company Estimates of Economic Value,
Net Book Value and Transition Cost of Fossil/Hydro Units
(Thousands of Dollars)

	Description	Asset Value In a Competitive Market (1)	Regulatory Net Book Value (2)	Transition Cost (3)	Adjusted to Revenue Requirements (4)
	FOSSIL PLANTS (Cont'd):				
40	Mt. Storm Power Station				
41	Unit #1				
42	Unit #2				
43	Unit #3	ALLEGED COMMERCIALLY			
44	CT				
45	Subtotal				
46	Yorktown Power Station				
47	Unit #1	SENSITIVE INFORMATION			
48	Unit #2				
49	Unit #3				
50	Subtotal				
51	Total Fossil	DELETED ***************			
	HYDRO:				
52	Cushaw Hydro Station				
53	Units #1-5	ALLEGED COMMERCIALLY			
54	Gaston Hydro Station				
55	Unit #1				
56	Roanoke Rapids Hydro Station	SENSITIVE INFORMATION			
57	Unit #1				
58	Total Hydro	DELETED ***************			
59	PUMPED HYDRO:				
60	Bath County Pumped Storage				
61	Unit #1				
62	Unit #2	ALLEGED COMMERCIALLY			
63	Unit #3				
64	Unit #4				
65	Unit #5				
66	Unit #6	SENSITIVE INFORMATION			
67	Subtotal				
68	Total Hydro and Pumped Hydro				
69	Total Fossil and Hydro	DELETED ***************			
70	Plus: Innsbrook/Lakeridge (see note				
71	Plus: Future Use				
72	Total Fossil and Hydro	*************************			

Column (1):

Column (2):

ALLEGED COMMERCIALLY

SENSITIVE INFORMATION

Column (3):

DELETED ****************

Column (4):

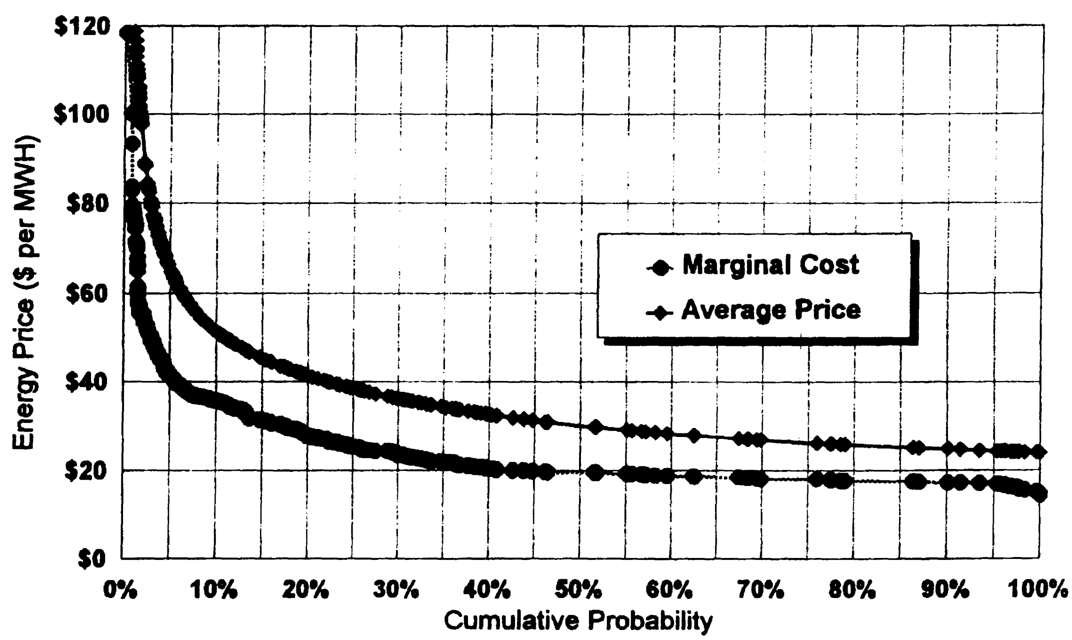
ALLEGED COMMERCIALLY

SENSITIVE INFORMATION

DELETED ****************

VIRGINIA ELECTRIC AND POWER COMPANY

Price Duration Curve Generated From
Results of MultiSym Model for the Year 2003



VIRGINIA ELECTRIC AND POWER COMPANY

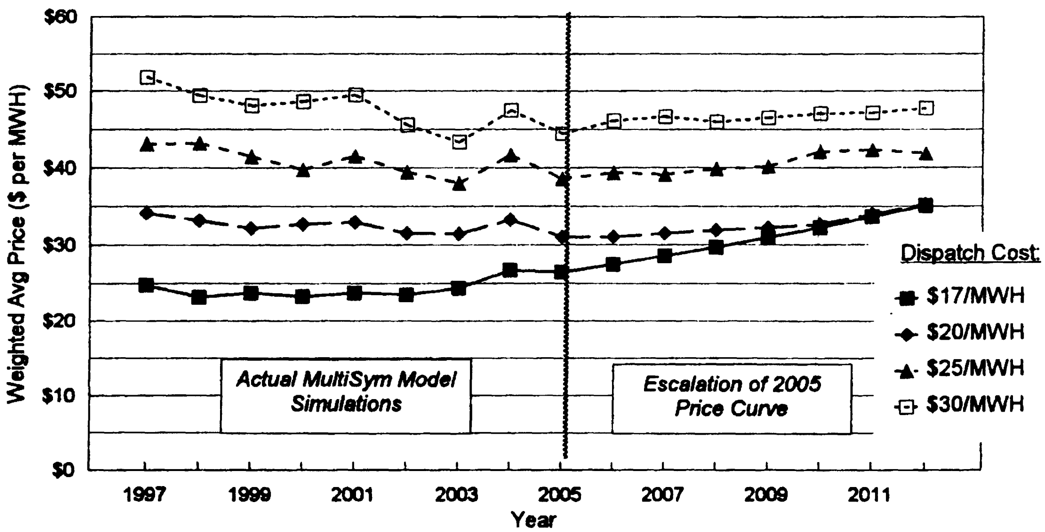
Price Duration Curve Generated From Results of MultiSym Model for the Year 2003

Ln	Marginal Cost (1)	Hours (2)	Cumulative Hours (3)	Cumulative Probability (4)	Probability (5)	Expected Value (6)	Total Expected Value (7)	Average Price (8)
1	14.60	1	8,760	100.0000%	0.0114%	0.0017	24.00	24.00
2	14.70	2	8,759	99.9886%	0.0228%	0.0034	24.00	24.01
3	14.80	10	8,757	99.9658%	0.1142%	0.0169	24.00	24.01
4	15.20	25	8,747	99.8516%	0.2854%	0.0434	23.98	24.02
5	15.30	106	8,722	99.5662%	1.2100%	0.1851	23.94	24.04
6	15.70	55	8,616	98.3562%	0.6279%	0.0986	23.75	24.15
7	15.90	4	8,561	97.7283%	0.0457%	0.0073	23.66	24.21
8	16.00	1	8,557	97.6826%	0.0114%	0.0018	23.65	24.21
9	16.10	4	8,556	97.6712%	0.0457%	0.0074	23.65	24.21
10	16.20	3	8,552	97.6256%	0.0342%	0.0055	23.64	24.21
11	16.30	22	8,549	97.5913%	0.2511%	0.0409	23.63	24.22
12	16.40	21	8,527	97.3402%	0.2397%	0.0393	23.59	24.24
13	16.50	24	8,506	97.1005%	0.2740%	0.0452	23.55	24.26
14	16.60	47	8,482	96.8265%	0.5365%	0.0891	23.51	24.28
15	16.70	10	8,435	96.2900%	0.1142%	0.0191	23.42	24.32
				■	■	■		
153	31.30	2	1,292	14.7489%	0.0228%	0.0071	6.72	45.56
154	31.40	101	1,290	14.7260%	1.1530%	0.3620	6.71	45.58
155	31.60	2	1,189	13.5731%	0.0228%	0.0072	6.35	46.79
156	31.70	1	1,187	13.5502%	0.0114%	0.0036	6.34	46.81
157	31.90	3	1,186	13.5388%	0.0342%	0.0109	6.34	46.83
158	32.00	6	1,183	13.5046%	0.0685%	0.0219	6.33	46.87
159	32.30	17	1,177	13.4361%	0.1941%	0.0627	6.31	46.94
160	32.50	2	1,160	13.2420%	0.0228%	0.0074	6.24	47.16
161	32.60	4	1,158	13.2192%	0.0457%	0.0149	6.24	47.18
162	32.70	1	1,154	13.1735%	0.0114%	0.0037	6.22	47.23
163	33.10	4	1,153	13.1621%	0.0457%	0.0151	6.22	47.24
164	33.20	4	1,149	13.1164%	0.0457%	0.0152	6.20	47.29
165	33.30	1	1,145	13.0708%	0.0114%	0.0038	6.19	47.34
166	33.40	26	1,144	13.0594%	0.2968%	0.0991	6.18	47.35
167	33.50	1	1,118	12.7626%	0.0114%	0.0038	6.09	47.68
				■	■	■		
305	75.60	4	99	1.1301%	0.0457%	0.0345	1.30	114.99
306	76.20	5	95	1.0845%	0.0571%	0.0435	1.27	116.65
307	76.70	3	90	1.0274%	0.0342%	0.0263	1.22	118.90
308	76.90	1	87	0.9932%	0.0114%	0.0088	1.20	120.35
309	78.10	5	86	0.9817%	0.0571%	0.0446	1.19	120.86
310	78.20	5	81	0.9247%	0.0571%	0.0446	1.14	123.50
311	78.30	1	76	0.8676%	0.0114%	0.0089	1.10	126.47
312	79.10	5	75	0.8562%	0.0571%	0.0451	1.09	127.12
313	79.40	1	70	0.7991%	0.0114%	0.0091	1.04	130.55
314	82.90	1	69	0.7877%	0.0114%	0.0095	1.03	131.29
315	83.80	2	68	0.7763%	0.0228%	0.0191	1.02	132.00
316	93.30	3	66	0.7534%	0.0342%	0.0320	1.01	133.46
317	100.00	52	63	0.7192%	0.5936%	0.5936	0.97	135.37
318	118.50	2	11	0.1256%	0.0228%	0.0271	0.38	302.59
319	340.00	6	9	0.1027%	0.0685%	0.2329	0.35	343.50
320	350.50	3	3	0.0342%	0.0342%	0.1200	0.12	350.50
					Total:	24.0046		

Columns (1), (2), and (4):	Information from Virginia Power Response to Question No. 28 included in the Sixth Set of Interogatories from VCFUR.
Column (3):	Cumulative number of hours starting with highest marginal cost.
Column (5):	[Column (4) line n] - [Column (4) line n+1].
Column (6):	Column (1) * Column (5).
Column (7):	Summation of Column (6) for all marginal costs in lines n and higher. (Example: Line 15 is the sum of Column (6) for lines 15 through 320.)
Column (8):	Column (7) / Column (4).

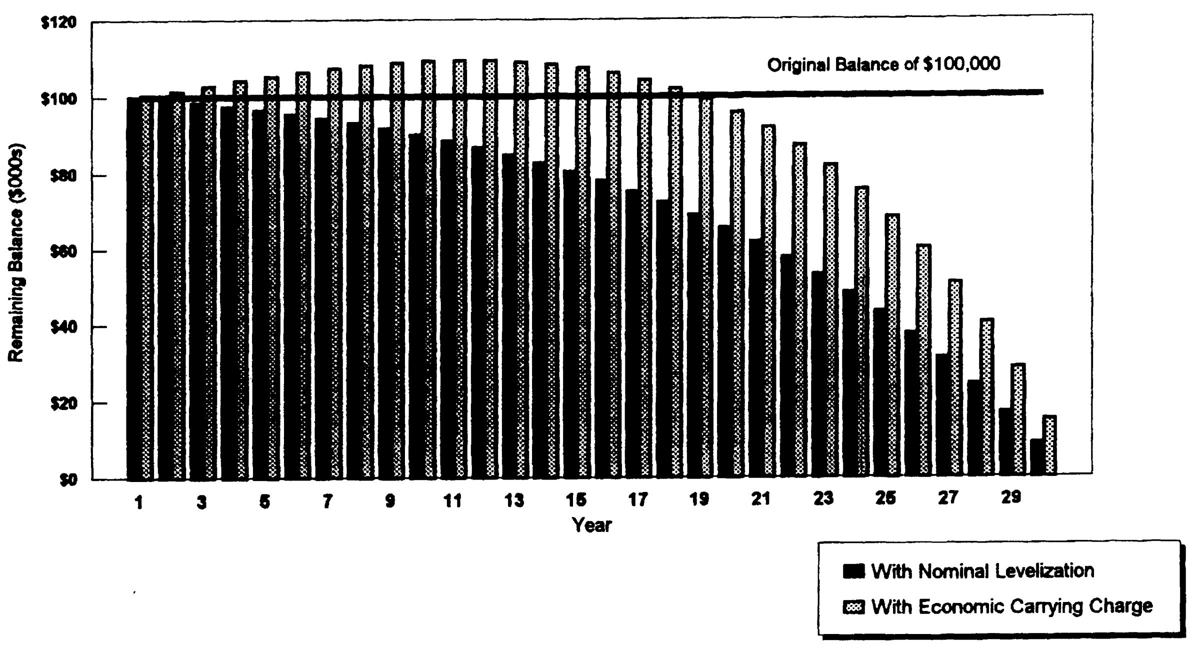
VIRGINIA ELECTRIC AND POWER COMPANY

Results of MultiSym Price Duration Curves 1997 - 2012
Average Prices Based on Various Dispatch Curves



VIRGINIA ELECTRIC AND POWER COMPANY

Example Comparing Nominally Levelized versus Economic Carrying Charge On Repayment of $100,000



VIRGINIA ELECTRIC AND POWER COMPANY

Example Comparing Nominally Levelized versus Economic Carrying Charge On Repayment of $100,000

	Payment Streams		Repayment with Nominally Levelized Stream			Repayment with Economic Carrying Charge		
Yr	Nominally Levelized (1)	Economic Carrying (2)	Remaining Balance (3)	Interest (4)	Principal Paid (5)	Remaining Balance (6)	Interest (7)	Principal Paid (8)
1	$9,561	$7,338	$100,000	$8,800	$761	$100,000	$8,800	($1,462)
2	$9,561	$7,544	$99,239	$8,733	$828	$101,462	$8,929	($1,385)
3	$9,561	$7,755	$98,410	$8,660	$901	$102,847	$9,051	($1,296)
4	$9,561	$7,972	$97,509	$8,581	$981	$104,142	$9,165	($1,193)
5	$9,561	$8,195	$96,528	$8,494	$1,067	$105,335	$9,269	($1,074)
6	$9,561	$8,425	$95,461	$8,401	$1,161	$106,409	$9,364	($939)
7	$9,561	$8,661	$94,300	$8,298	$1,263	$107,349	$9,447	($786)
8	$9,561	$8,903	$93,037	$8,187	$1,374	$108,135	$9,516	($613)
9	$9,561	$9,152	$91,663	$8,066	$1,495	$108,747	$9,570	($417)
10	$9,561	$9,409	$90,167	$7,935	$1,627	$109,165	$9,607	($198)
11	$9,561	$9,672	$88,541	$7,792	$1,770	$109,363	$9,624	$48
12	$9,561	$9,943	$86,771	$7,636	$1,926	$109,315	$9,620	$323
13	$9,561	$10,221	$84,845	$7,466	$2,095	$108,991	$9,591	$630
14	$9,561	$10,507	$82,750	$7,282	$2,279	$108,361	$9,536	$972
15	$9,561	$10,802	$80,471	$7,081	$2,480	$107,390	$9,450	$1,351
16	$9,561	$11,104	$77,991	$6,863	$2,698	$106,038	$9,331	$1,773
17	$9,561	$11,415	$75,292	$6,626	$2,936	$104,265	$9,175	$2,240
18	$9,561	$11,735	$72,357	$6,367	$3,194	$102,026	$8,978	$2,756
19	$9,561	$12,063	$69,162	$6,086	$3,475	$99,269	$8,736	$3,328
20	$9,561	$12,401	$65,687	$5,780	$3,781	$95,942	$8,443	$3,958
21	$9,561	$12,748	$61,906	$5,448	$4,114	$91,984	$8,095	$4,654
22	$9,561	$13,105	$57,792	$5,086	$4,476	$87,330	$7,685	$5,420
23	$9,561	$13,472	$53,317	$4,692	$4,870	$81,910	$7,208	$6,264
24	$9,561	$13,849	$48,447	$4,263	$5,298	$75,646	$6,657	$7,193
25	$9,561	$14,237	$43,149	$3,797	$5,764	$68,453	$6,024	$8,213
26	$9,561	$14,636	$37,385	$3,290	$6,272	$60,240	$5,301	$9,335
27	$9,561	$15,046	$31,113	$2,738	$6,824	$50,905	$4,480	$10,566
28	$9,561	$15,467	$24,289	$2,137	$7,424	$40,339	$3,550	$11,917
29	$9,561	$15,900	$16,865	$1,484	$8,077	$28,422	$2,501	$13,399
30	$9,561	$16,345	$8,788	$773	$8,788	$15,023	$1,322	$15,023
NPV	$100,000	$100,000						

Assumptions:

Inflation Rate: *2.80%* *Interest Rate:* *8.80%* *Initial Cost:* *$100,000*

Column (1): Levelized payment stream.
Column (2): Payment based on economic carrying charge, increasing at rate of inflation.
Column (3): Previous line of Column (3) - Previous line of Column (5).
Column (4): Column (3) * Interest Rate.
Column (5): Column (1) - Column (4).
Column (6): Previous line of Column (6) - Previous line of Column (8).
Column (7): Column (6) * Interest Rate.
Column (8): Column (2) - Column (7).

VIRGINIA ELECTRIC AND POWER COMPANY

Derivation of Capacity Reservation Value And Value of CT Energy Generation

Yr	Virginia Power's Total Capacity Cost ($/kW-mo)	($/kW-yr)	Nominally Levelized	Fixed O&M	Total	Energy Credit	Net Capacity Value
			(All amounts shown as $ per kW-year)				
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1997	$1.91	$22.90	$34.82	$17.00	$51.82		
1998	$1.96	$23.55	$35.80	$17.48	$53.28		
1999	$2.02	$24.22	$36.80	$17.97	$54.77		
2000	$2.08	$24.91	$37.84	$18.47	$56.31		
2001	$2.14	$25.62	$38.90	$18.99	$57.89		
2002	$2.20	$26.36	$39.99	$19.53	$59.52	$9.61	$49.91
2003	$2.26	$27.11	$41.12	$20.08	$61.19	$8.55	$52.64
2004	$2.32	$27.89	$42.27	$20.64	$62.91	$18.79	$44.13
2005	$2.39	$28.69	$43.46	$21.22	$64.68	$12.21	$52.47
2006	$2.46	$29.51	$44.68	$21.82	$66.50	$12.93	$53.57
2007	$2.53	$30.36	$45.94	$22.43	$68.37	$13.69	$54.68
2008	$2.60	$31.23	$47.23	$23.06	$70.29	$14.50	$55.78
2009	$2.68	$32.12	$48.56	$23.71	$72.26	$15.36	$56.90
2010	$2.75	$33.04	$49.92	$24.37	$74.29	$16.30	$58.00
2011	$2.83	$33.99	$51.32	$25.06	$76.38	$17.51	$58.87
2012	$2.91	$34.96	$52.77	$25.76	$78.53	$18.82	$59.71

Assumptions:

Escalation: *2.81%* *Discount Rate:* *7.73%*

Column (1): For years 2003+, see TCR, page 16. For years prior to 2003, column (2) / 12.
Column (2): Virginia Power Response to Question No. 35 included in the Sixth Set of Interrogatories from VCFUR.
Column (3): Nominally levelized payment based on 1997 total cost; escalated for years 1998 forward. Escalation rates and discount rate from Virginia Power Response to Question No. 35 included in the Sixth Set of Interrogatories from VCFUR. Initial Cost of $300 per kW.
Column (4): "Assumptions for the Annual Energy Outlook 1997", EIA, December 1996, p. 58.
Column (5): Column (3) + Column (4).
Column (6): See Page 2 of this schedule.
Column (7): Column (5) - Column (6).

VIRGINIA ELECTRIC AND POWER COMPANY

Derivation of Capacity Reservation Value
And Value of CT Energy Generation

Yr	Dispatch Cost (\$/MWH) (1)	Capacity Factor (2)	Average Price (\$/MWH) (3)	Energy Credit (\$/MWH) (4)	Total Credit (\$ / kW) (5)
2002	$44.66	2.97%	$81.63	$36.97	$9.61
2003	$46.39	3.70%	$72.78	$26.39	$8.55
2004	$48.21	4.16%	$99.82	$51.61	$18.79
2005	$50.41	3.56%	$89.55	$39.14	$12.21
2006	$52.30	3.68%	$92.46	$40.16	$12.93
2007	$54.29	3.77%	$95.76	$41.47	$13.69
2008	$56.31	3.77%	$100.26	$43.95	$14.50
2009	$58.42	3.78%	$104.83	$46.41	$15.36
2010	$60.53	3.87%	$108.61	$48.08	$16.30
2011	$62.08	4.09%	$110.99	$48.91	$17.51
2012	$63.63	4.09%	$116.20	$52.57	$18.82
Average	$54.29	3.77%	$97.54	$43.24	$14.39

Column (1): Virginia Power Response to Question No. 35 included in the Sixth Set of Interrogatories from VCFUR.

Column (2): Based on the price duration curves for 2002 through 2012, the capacity factor which supports the dispatch cost. See also the spreadsheet file "fpc596r.xlw" provided in Virginia Power Response to Question No. 9 included in the Sixth Set of Interrogatories from VCFUR.

Column (3): Based on the price duration curves for 2002 through 2012, the average price corresponding to the dispatch cost and capacity factor. See also file referenced above.

Column (4): Colum (3) - Column (1).
Column (5): Column (4) * Column (2) * 8.76.

VIRGINIA ELECTRIC AND POWER COMPANY

Results of Changes to Virginia Power Assumptions
In Estimating Transition Costs
(Thousands of Dollars)

Ln	Description	As Filed By Company	Adjustment For Correction to Roanoke Rapids*	Individual Adjustments to Estimated Transition Costs: Revised Capacity Prices 2003 - 2015	Extending Analysis To 2025	Revised Capacity Costs 2016 - 2025	Extending Analysis To 2035	Revised Capacity Costs 2026 - 2035
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Fossil Plants	($727,710)	$0	($1,361,681)	($1,439,553)	($518,377)	($1,070,060)	($330,866)
2	Hydro Plants	$108,679	($17,208)	($262,927)	($330,237)	($100,094)	($208,375)	($63,887)
3	Subtotal Fossil & Hydro	($619,030)	($17,208)	($1,624,608)	($1,769,790)	($618,471)	($1,278,435)	($394,752)
4	Plus: Other and Future Plant	$17,703	$0	$0	$0	$0	$0	$0
5	Total Fossil & Hydro	($601,328)	($17,208)	($1,624,608)	($1,769,790)	($618,471)	($1,278,435)	($394,752)
6	Nuclear	$787,291	$0	($416,413)	($195,316)	($42,828)	($0)	$0
7	Subtotal - Generation	$185,963	($17,208)	($2,041,021)	($1,965,106)	($661,299)	($1,278,435)	($394,752)
8	NUG Contracts	$3,015,199	$0	($487,273)	$186,803	($75,117)	$0	$0
9	Total System	$3,201,162	($17,208)	($2,528,294)	($1,778,303)	($736,416)	($1,278,435)	($394,752)
10	Virginia Jurisdiction	$2,464,984	($13,251)	($1,946,858)	($1,369,343)	($567,061)	($984,431)	($303,970)

* The correction to Roanoke Rapids is retained in columns 3 through 7.

VIRGINIA ELECTRIC AND POWER COMPANY

Results of Changes to Virginia Power Assumptions In Estimating Transition Costs (Thousands of Dollars)

Ln	Description	As Filed By Company (1)	Correction to Roanoke Rapids* (2)	Cumulative Adjustments to Estimated Transition Costs: Revised Capacity Prices 2003 - 2015 (3)	Extending Analysis To 2025 (4)	Revised Capacity Costs 2016 - 2025 (5)	Extending Analysis To 2035 (6)	Revised Capacity Costs 2026 - 2035 (7)
1	Fossil Plants	($727,710)	($727,710)	($2,089,391)	($3,528,944)	($4,047,321)	($5,117,381)	($5,448,247)
2	Hydro Plants	$108,679	$91,471	($171,456)	($501,693)	($601,787)	($810,162)	($874,049)
3	Subtotal Fossil & Hydro	($619,030)	($636,239)	($2,260,847)	($4,030,637)	($4,649,108)	($5,927,543)	($6,322,296)
4	Plus: Other and Future Plant	$17,703	$17,703	$17,703	$17,703	$17,703	$17,703	$17,703
5	Total Fossil & Hydro	($601,328)	($618,536)	($2,243,144)	($4,012,934)	($4,631,405)	($5,909,840)	($6,304,593)
6	Nuclear	$787,291	$787,291	$370,878	$175,562	$132,734	$132,734	$132,734
7	Subtotal - Generation	$185,963	$168,755	($1,872,266)	($3,837,372)	($4,498,671)	($5,777,106)	($6,171,859)
8	NUG Contracts	$3,015,199	$3,015,199	$2,527,926	$2,714,728	$2,639,611	$2,639,611	$2,639,611
9	Total System	$3,201,162	$3,183,954	$655,659	($1,122,644)	($1,859,060)	($3,137,495)	($3,532,248)
10	Virginia Jurisdiction	$2,464,984	$2,451,734	$504,876	($864,467)	($1,431,528)	($2,415,959)	($2,719,930)

* The correction to Roanoke Rapids is retained in columns 3 through 7.

COMMONWEALTH OF VIRGINIA
BEFORE THE
STATE CORPORATION COMMISSION

STATE CORPORATION COMMISSION	:	
	:	
	:	CASE NO. PUE2003-00062
	:	
In the matter of developing consensus	:	
Recommendations on stranded costs	:	

RESPONSE OF
WASHINGTON GAS ENERGY SERVICES, INC.
TO DESIGNATED QUESTIONS

Pursuant to the "Order Establishing Proceeding" issued by the State Corporation Commission (Commission) on March 3, 2003 in this proceeding, Washington Gas Energy Services, Inc. (WGES) hereby submits these responses to the eight questions listed in the order.

STATUTORY FRAMEWORK

The establishment of competitive retail electricity markets in Virginia is in a transition period that will extend through July 1, 2007 under the Virginia Electric Choice Act. The development of retail competition during this transition period is to be governed by the provisions of the Act and the manner in which the Commission implements the provisions which are discretionary.

The Commission may require electric utilities to provide capped bundled service from January 1, 2001 through July 1, 2007 (§56-582(A)(1), subject to certain adjustments allowed under §56-582(B)). However, a utility may petition the Commission to terminate capped rates to all customers anytime after January

1, 2004. The Commission may approve such termination only if it finds "an effectively competitive market for generation services within the service territory of that utility" (§56-582(C)).

The Act authorizes an electric utility to recover "just and reasonable net stranded costs to the extent that they exceed zero value" provided that the utility recovers such costs "through either capped rates" or "wires charges" (§56-584). Capped rate bundled and generation services became effective in Virginia on January 1, 2002, and each utility has been collecting some amount of net stranded costs since that date to the extent such costs apply.

Questions Presented

The Commission has sought responses to eight questions as part of the working group process. WGES provides its initial responses below.

1. Define "stranded costs." Include in the definition a detailed listing of each stranded cost component. Is this definition applicable to all electric utilities operating in Virginia? If not, to which utility or utilities does it apply and why?

Response: In Missouri PSC Case No. EW-97-245, stranded costs were defined "as the embedded investment made by electric utilities to provide service to customers that will not be recoverable in the price of electricity in a competitive market."[1] The New Hampshire Restructuring Act, RSA 374-F:2, IV[2] states that "...'Stranded costs' means costs, liabilities, and investments, such as uneconomic assets, that electric utilities would reasonably expect to recover if the existing regulatory structure with retail rates for the bundled provision of electric service continued and that will not be recovered as a result of

[1] *In the Matter of A Commission Inquiry Into Retail Competition. Missouri PSC Case No. EW-97-245. Report of the Stranded Cost Working Group to the Retail Electric Competition Task Force.*

restructured industry regulation that allows retail choice of electricity suppliers, unless a specific mechanism for such cost recovery is provided. Stranded costs may only include costs of:

> (a) Existing commitments or obligations incurred prior to the effective date of this chapter;
>
> (b) Renegotiated commitments approved by the commission; and
>
> (c) New mandated commitments approved by the commission."

In the preceding view, the utilities bear the burden of proof for stranded costs. This means that no utility could be allowed to recover through stranded cost surcharges any cost that it could not reasonably expect to recover under traditional ratemaking regulations.

The New Hampshire Public Utilities Commission further opined that "we find that the most appropriate definition of stranded cost is "net" sunk generation cost (including generation-related regulatory assets) that ordinarily would not be recovered if retail consumers were allowed access to alternative generation resources...by "net" we mean the aggregate value of assets that have market values in excess of book and assets that have book values in excess of market."[3]

The SCC Staff also had this to say: "Any stranded cost recovery policy should be provided as an opportunity and not a guarantee. Further, any such recovery, at a minimum, should be net of stranded margins, reflective of maximum utility mitigation efforts, and limited to historical, prudent, and necessary utility investment. Finally, stranded cost recovery should be

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[2] See House Bill 1392, 1996 at www.gencourt.state.nh.us/legislation/1996/hb1392.htm

[3] February 28, 1997 Restructuring New Hampshire's Electric Utility Industry: Final Plan, PUC DR 96-150, p. 43.

contingent upon the best efforts of the utility to foster development of appropriate competitive market structures."[4]

Stranded costs can thus generally be defined as the difference between the book value of a utility's generation assets and what those assets are worth in a competitive market. This definition should apply whether or not a utility divests itself of its generation assets or files a functional separation plan transferring its generation assets to an affiliate. In the former instance, the measure of stranded costs is determined by the market price of the divested assets. In the latter instance where a utility transfers its generation assets to an affiliate, the measure of stranded costs is an administrative one based on the Commission's assessment of market value. In either case, there may be stranded benefits (market price is greater than book value) or stranded costs (market price is less than book value). These general definitions should apply to all electric utilities in Virginia.

A general stranded cost framework should encompass, at a minimum, the following:

1. Generating assets
2. Long term NUG contracts
3. Nuclear decommissioning charges
4. Mandatory public benefits programs charges

[4] VA SCC Draft Working Model for Restructuring the Electric Utility Industry. Chapter 4, Stranded Cost. See also www.state.va.us/scc/caseifo/pue/case/streprt4.htm

5. Net regulatory assets related to generation, not transmission and distribution facilities, that could be booked in the year of occurrence but are amortized over time.

6. Stranded benefits stemming from over-funded utility pension plans or deferred taxes collected in rates in advance of payment to the taxing authorities.

A more detailed approach can be found in the City of Philadelphia stranded cost report: A Guide to Stranded Cost Valuation and Calculation Methods.[5] The report sets forth the following stranded cost principles:

1. Stranded costs are payments for sunk and past obligations.

2. Stranded costs should not include operating subsidies.

3. Stranded costs should be based on an independent audit of the book value of plants and regulatory assets.

4. Stranded costs should reflect careful scrutiny of recent capital additions for reasonableness.

5. Stranded costs should generally exclude fuel contracts and inventories.

6. Stranded costs should generally exclude general and common plant not located at power plants sites.

7. Stranded costs should be analyzed to remove costs that are not actually stranded, to insure there is no double-counting of costs and to avoid operating subsidies.

8. In computing stranded costs, utilities should credit ratepayers with the value of normalized deferred taxes when power plants are assigned a market value under tax law.

2. Define "just and reasonable net stranded costs." Provide a detailed explanation of how and why it differs from "stranded costs." Is this definition applicable to all electric utilities operating in Virginia? If not, to which utility or utilities does it apply and why?

Response. Unmitigated stranded costs by definition are "gross stranded costs" and as noted above reflect the difference between the book value of a utility's generation assets and what the assets are worth in a competitive market. Stranded costs that remain after mitigation measures are undertaken are "net stranded costs." Just and reasonable net stranded costs are prudently incurred net stranded costs that an electric utility should be entitled to recover as "transition costs." They remain costs that are permitted to be collected from ratepayers under a regulatory scheme, but that might not be recoverable in a competitive market environment. Functionally, one might look at a situation where the net difference between the market value and book value of generation assets would result and stranded benefits would produce net stranded costs.

Consider this example:

Generation Plant X book value = $250 million more than market value
Generation Plant Y book value = $80 million below market value

Therefore, net stranded cost = $170 million ($250 minus $80)

This definition should apply to all electric utilities operating in Virginia.

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[5] February 1997 City of Philadelphia Stranded Cost Report: A Guide to Stranded Cost Valuation and Calculation Methods. Prepared by William B. Marcus of JBS Energy and Jan Hamrin of HMW International. See also www.jbsenergy.com/downloads/strand97.html.

3. <u>Provide a methodology for calculating "just and reasonable net stranded costs." Be specific in providing the necessary steps, beginning with each component comprising gross stranded costs and each component offsetting this amount to reach a net amount.</u>

<u>Response</u>. Under the Working Group concept, each utility should be required to provide information which identifies its gross stranded costs based on the competitive market and that describes the mitigation measures it intends to pursue. The Working Group, led by the SCC, should develop a general framework upon which to produce stranded costs results based on the same information provided by the utilities. The Commission could set each proceeding for hearing to determine the reasonableness of the utility's proposal and make a finding of the just and reasonable net stranded costs that the utility is entitled to recovery through July 1, 2007 under § 56-584. However, under the collaborative approach, the Working Group might wish to consider developing a straw man methodology to calculate net stranded costs for each utility company.

WGES would like to point out that the utilities still have the option of voluntarily selling their generation assets. PEPCO sold its generating assets and produced a consumer surplus (a net stranded benefit). GPU Energy in New Jersey (JCP&L) also had a similar, favorable market experience.

Another approach is a spin-down or transfer of generation assets to a utility affiliate accompanied by an issue of stock in the new entity to existing shareholders. The new affiliate stock would then be traded publicly. This approach would achieve a market valuation without forced divestiture through stock valuation. Stranded cost would be determined by offsetting the stock price from the net book value of the utility's generation assets.

4. Describe how "stranded costs" are recovered. Provide a methodology for calculating such recovery. Describe the recovery period.

Response. Just and reasonable "net stranded costs" must be recovered either through wires charges determined under §56-583 or capped bundled rates determined under §56-582. To the extent that utilities have net stranded costs, they are currently being recovered either in capped bundled sales rates or through wires charges at this time. Presently, electric utilities are only calculating wires charges annually. By statute, all net stranded costs are to have been determined and collected by July 1, 2007. The methodology for calculating the recovery of stranded costs under §56-583 or §56-582 is as follows: identify net stranded costs; allocate net stranded costs to each customer class under current rate schedules; compute a wires charge for each customer class based on allocated net stranded costs to that class and amortizing such costs over the remaining transition period through July 1, 2007.

5. Do the calculation and recovery methodologies described in responses to questions 3 and 4 produce (or are they likely to produce) over-recovery or under-recovery of just and reasonable net stranded costs? How should over- or under-recovery be dealt with?

Response. It is likely that wires charges applicable to each customer class will not collect the net stranded costs allocated to each class. There should be a true up procedure to recalculate wires charges "not more frequently than annually" as provided under §56-583(A).

6. Requested Actions paragraph 1 of the LTTF Resolution requests that the work group develop consensus recommendations "consistent with the provisions of the Act." Explain how that phrase guides or possibly constrains the actions of the work group. Identify each section of the Virginia Electric Utility Restructuring Act, § 56-576 to –596 of Code of Virginia, pertinent to such guidance or constraint.

Additionally, explain each such section's significance in the context of definitions offered in response to questions 1 and 2 as well as in the methodologies proffered for calculations and recovering just and reasonable net stranded costs in response to questions 3 and 4.

Response. Paragraph 1 of the LTTF Resolution asks for "consensus recommendations" the issues listed in paragraphs 2 and 3 of the resolution. These issues include (1) the definition of "stranded costs," (2) the definition of "just and reasonable net stranded costs, " (3) the methodology to be applied in calculating each utility's "just and reasonable net stranded costs, amounts recovered or to be recovered, to offset such costs", and (4) "whether such recovery has resulted in or is likely to result in the over-recovery or under-recovery of such costs",

It is possible and perhaps even likely that "consensus" recommendations may not be achieved by the working group even Working in Good faith. In that case, the Commission should proceed to make the required statutory determinations in evidentiary proceedings.

7. Provide copies of any study or studies undertaken to define and/or calculate stranded costs for any Virginia electric utility.

Response. Utilities should be required to provide such information to the Commission and to the Parties as part of the LTTF process. See footnote 5 above.

8. Provide any additional comments on the issues raised by Requested Actions paragraphs 2 and 3 of the LTTF Resolution.

Response. It is incumbent on the Commission and on utilities to establish the amount of just and reasonable net stranded costs that have been recovered to date and that are to be recovered through July 1, 2007, in order that customers and retail suppliers may know what the rules of market participation are. Until that is done, retail suppliers and customers cannot know what competitive benchmarks they face in competing with an incumbent utility's capped generation rates in the first instance and eventually against each other once the incumbent utility's competitive generation option is known. Unless this is done, the development of retail competition in Virginia will remain stymied.

Respectfully submitted,

____
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Attorney for:

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March 21, 2002

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Response of Washington Gas Energy Services, Inc. was served electronically this twenty first day of March 2003 to the parties on the service list in Case No. PUE2003-00062.

Telemac N. Chryssikos
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National Energy Marketers Association

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

COMMONWEALTH OF VIRGINIA, ex rel.

STATE CORPORATION COMMISSION

In the Matter of Developing Consensus Recommendations on Stranded Costs — **Case No. PUE-2003-00062**

INITIAL COMMENTS OF THE NATIONAL ENERGY MARKETERS

The National Energy Marketers Association hereby submits its responses to the questions set forth in the Order Establishing Proceeding issued March 3, 2003, in the above-referenced proceeding.

The National Energy Marketers Association (NEM) is a national, non-profit trade association representing wholesale and retail marketers of energy, telecom and financial-related products, services, information and related technologies throughout the United States, Canada and the U.K. NEM's Membership includes wholesale and retail suppliers of electricity and natural gas, independent power producers, suppliers of distributed generation, energy brokers, power traders, and electronic trading exchanges, advanced metering and load management firms, billing and information technology providers, credit, risk management and financial services firms, software developers, clean coal technology firms as well as energy-related telecom, broadband and internet companies.

This regionally diverse, broad-based coalition of energy, financial services and technology firms has come together under NEM's auspices to forge consensus and to help resolve as many issues as possible that would delay competition. NEM members urge lawmakers and regulators to implement:

- Laws and regulations that open markets for natural gas and electricity in a competitively neutral fashion that bring suppliers and consumers together at the lowest possible cost;

- Standard rates, tariffs, taxes and operating procedures that unbundle competitive services from monopoly services and encourage true competition on the basis of price, quality of service and provision of value-added services;
- Accounting and disclosure standards to promote the proper valuation of energy assets, equity securities and forward energy contracts, including derivatives; and
- Policies that encourage investments in new technologies, including the integration of energy, telecom, digital communications and Internet services to lower the cost of energy and related services.

1. Define "stranded costs." Include in the definition a detailed listing of each stranded cost component. Is this definition applicable to all electric utilities operating in Virginia? If not, to which utility or utilities does it apply and why?

NEM submits that any determination of costs that are truly stranded must necessarily address the issue of whether the "unavoidable" costs at issue are, in fact, costs properly attributable to Provider of Last Resort-related services. Accordingly, NEM urges the Commission to implement embedded cost-based unbundled rates at the earliest possible time and to quantify the levels of migration and monitor utility mitigation efforts prior to developing just and reasonable methods to ensure utilities receive the appropriate revenue requirements based on the embedded costs associated with the actual services provided to migrating customers versus full sales customers versus POLR customers.

NEM recommends that any costs that are unavoidable because utilities must incur such costs to perform Provider of Last Related (POLR)-related services should be recovered through adjustments to the rates charged for POLR-related services. Utilities should not be permitted to recover revenue shortfalls through a transition surcharge in delivery rates based on a formula that assumes all unavoidable costs are caused by migration rather than by the necessity to provide POLR-related services. Any actual unrecovered costs or revenues lost that are not connected with the utilities' provision of POLR-related services and/or fully bundled sales service should be added to distribution rates in a competitively neutral fashion.

2. Define "just and reasonable net stranded costs." Provide a detailed explanation of how and why it differs from "stranded costs." Is this definition applicable to all electric utilities operating in Virginia? If not, to which utility or utilities does it apply and why?

The term "just and reasonable net stranded costs" requires a determination of whether or not the utilities have any stranded costs and whether those costs are offset by any stranded benefits. The qualifier "just and reasonable" also imparts a utility obligation to productively manage and mitigate net stranded costs.

3. Provide a methodology for calculating "just and reasonable net stranded costs." Be specific in providing the necessary steps, beginning with each component comprising gross stranded costs and each component offsetting this amount to reach a net amount.

NEM recommends that the methodology for calculating "just and reasonable net stranded costs" should be implemented after just and reasonable unbundled rates or shopping credits based on fully embedded costs have been implemented and actual migration has occurred. A reasonable period of time (e.g. one year or a migration rate of 25%) should be given to customers to comparison shop with shopping credits based on fully embedded cost-based unbundled rates (i.e. credits against utility bills) for contestable services.

Once a reasonable time (e.g. one year or 25% migration) has elapsed during which consumers are able to shop for one or more competitive services with embedded cost-based credits, then a calculation of the difference between the revenues that the utility would have received using fully embedded cost-based rates and the revenues actually received by the utility due to lost sales of specific services from the menu of competitive products, services, information and technology that each customer actually elects to purchase from the utility versus a competitive supplier should be compared to determine the maximum amount of potentially "qualifying revenue losses" that may be arguably recoverable, subject to the following qualifications:

1. The utility must show that the costs are material.
2. The utility must demonstrate that they have productively managed and reasonably mitigated costs in the subject areas.
3. The utility must not be earning in excess of their earnings/sharing cap, and
4. The utility must identify specifically which costs or revenue losses are a result of (a) the utility being required to provide POLR services and/or (b) the utility's need to provide fully bundled services to customers that do not migrate.

NEM also recommends that the methodology for calculating "just and reasonable net stranded costs" must be implemented in a manner that provides market participants with long term certainty as to the amount of the charge and the duration over which it will be imposed. For example, recalculation of the charge on a yearly basis will impose a large degree of uncertainty on market participants as to whether they can cost-effectively serve customers on a long-term basis. In order for competitive providers to make the infrastructure investments necessary to serve retail access customers, they must be provided with long-term certainty as to the viability of the Virginia retail marketplace.

Relatedly, a date certain should be established after which stranded costs are deemed fully recovered and the need for wires charges is eliminated. Competitive market participants and the consumers they wish to serve must be given a clear indication of the term of stranded cost recovery so they can form adequate and rational business plans with respect to serving the Virginia market.

4. Describe how stranded costs are recovered. Provide a methodology for calculating such recovery. Describe the recovery period.

NEM supports the competitively-neutral recovery of stranded costs, if and when, they occur. NEM also believes that net stranded costs should be recovered from all customers, whether they receive utility sales service or competitively provided service, on a competitively neutral basis. Recovering stranded costs solely from departing customers penalizes consumers who shop for lower priced energy and should not be permitted for a number of reasons as set forth below including: a) all customers benefit from robust retail energy price competition; b) competitively neutral charges are necessary to provide market participants with long term certainty to make investments in the Virginia market; c) if stranded cost charges are not assessed on a competitively neutral basis, inaccurate price signals will be sent to consumers; d) a competitively neutral stranded cost charge will eliminate the issue of uncertainty with respect to using retail open access load forecasts to set charge amounts; and e) a competitively neutral stranded cost charge will avoid the "retail access death spiral" effect.

a. All Customers Benefit from Robust Retail Energy Price Competition and Therefore All Customers Should Share the Cost

True price competition benefits all customers, not just those who shop for lower prices. The first and foremost benefit provided is the economic stimulus provided by economically efficient competitively priced energy as well as the ability to exercise choice beyond the regulated service they have traditionally received. It is unfair and unwise to penalize those customers who attempt to lower their energy costs as it defeats the entire purpose of permitting price competition in the first instance. If a charge applicable only to retail access customers is set too high, no one will be able to participate in the market. Assessment of stranded cost charges only against retail access customers will not only punish migrating customers, thereby slowing migration and the development of functional retail markets, but it will also encourage utilities to continue to invest in competitive services thereby further increasing future potentially "stranded" costs. In the end, society will pay a far higher transition cost the longer utilities remain in competitive lines of businesses.

b. Competitively Neutral Stranded Cost Charges Provide Marketers with Much Needed Long Term Certainty

Competitively neutral stranded cost charges will benefit the long-term development of the market by providing competitive marketers with the long-term certainty needed to justify the infrastructure investments of serving customers. For example, if stranded cost charges are set on a yearly basis and only imposed on retail access customers there will be a continuous risk that future stranded cost charges will make competitive offerings uneconomic. Without competitive neutrality, robust competition cannot evolve and the benefits that competition is intended to bring to Virginia cannot be realized.

c. A Stranded Cost Charge Billed Only to Customers Who Choose To Participate In Electric Customer Choice Masks Market Price Signals and Leads To Uneconomic Customer Purchases

Adding an incremental, non-market based charge to the cost of purchasing from market based sources and not to the cost of purchasing from the utility is clearly discriminatory and may cause customers to purchase energy from the utility when the utility's energy costs are higher. In other words, consumers will not be provided with a true comparison of utility and competitive service if the utility price-to-beat is comprised of commodity costs only and the competitive supplier's price is comprised of commodity costs and a stranded cost charge. The price signals will be obscured because of the stranded cost charge applied in a discriminatory fashion. The "one size fits all" product structures forces customers to pay for the inefficiencies embedded in regulated rates and the reliance on arduous regulatory proceedings will continue. This, in turn, will perpetuate economic inefficiency and higher than necessary energy costs for Virginia consumers. Putting in place a competitively neutral stranded cost recovery method will eliminate the risk that the utility's merchant service, which may not otherwise be an economically efficient choice, could displace competitively priced alternatives when those alternatives are a better or lower cost choice.

d. A Charge Applicable to All Customers Eliminates The Issue Of Uncertainty With Regard To ROA Load Forecasts Being Used To Set Charge Amounts

Given the very short history of electric competition and the dramatic impact that market price swings and utility surcharges can have on the economics of competitive choice, utility retail access load forecasting is at best arbitrary. Since the level of a per kWh charge can have dramatic impacts on customer choice, the utility would have an incentive to mis-forecast. The utilities and the Commission Staff have decades of experience in forecasting the utilities' total system load. Therefore, if the charge were applicable to all customers, the load forecast used to determine the charge per kWh would be very accurate and the probability of significant over- or under- collection would be greatly diminished. This increased certainty of collection should improve utility cash flows and mitigate skepticism on the part of capital markets and rating agencies.

e. Assessing Stranded Cost Charges Only Against Retail Access Customers Will Have a Detrimental Downward Spiral Effect

Utilization of a competitively neutral stranded cost charge will avoid the "retail access death spiral" effect that is inherent in a charge assessed against only retail access customers. Under this scenario, as customers return to utility service, the stranded cost charge increases as the number of customers against whom it can be assessed decreases. The result is to encumber the remaining retail access customers with disproportionately more costs thereby forcing their return to the utility's bundled service to avoid the imposition of the escalating stranded cost charge. This will cause further returns to the utility's bundled service, and ultimately the demise of the retail access program. Penalizing migrating customers can create a "retail access death spiral" which must be avoided.

5. Do the calculation and recovery methodologies described in responses to questions 3 and 4 produce (or are they likely to produce) over-recovery or under-recovery of just and reasonable net stranded costs? How should such over- or under-recovery be dealt with?

As a general matter, NEM believes that utility rates should be unbundled based on the utilities' fully embedded costs. To do otherwise will cause the utilities to incur much higher stranded costs. If utilities' rates reflect and utility customers pay less than fully embedded costs, customers will be paying an artificially low, subsidized price for competitively available services. If utilities' unbundled rates reflect and utility customers pay less than fully embedded costs, customers end up paying twice for these services. In conjunction, these two effects will slow customer migration and utilities will continue to incur costs for competitive services that may ultimately become stranded. In contrast, unbundled utility rates based on fully embedded costs will allow utilities to both quantify and, if properly mitigated, recover stranded costs within a reasonable time frame. It will also provide customers and competitors with true, accurate price signals that will permit meaningful price competition in the shortest possible time.

6. Requested Actions paragraph 1 of the LTTF Resolution requests that the work group develop consensus recommendations "consistent with the provisions of the Act." Explain how that phrase guides or possibly constrains the actions of the work group. Identify each section of the Virginia Electric Utility Restructuring Act, §§ 56-576 to -596 of the Code of Virginia, pertinent to such guidance or constraint. Additionally, explain each such section's significance in the context of definitions offered in response to questions 1 and 2 as well as in the methodologies proffered for calculating and recovering just and reasonable net stranded costs in response to questions 3 and 4.

The major statutory constraint faced by the workgroup in developing consensus recommendations is the requirement imposed by Section 56-583(B) that the wires charge be assessed to retail access customers only. Net stranded costs should be collected on a competitively neutral basis (see Response to Question 4 above). This provision prevents that result by penalizing customers that switch with a wires charge to collect stranded costs. NEM submits that the wires charge as currently instituted is a major barrier to competitive entry and should be reexamined consistent with the Commission's authority, vested in Section 56-596, to, "take into consideration, among other things, the goals of advancement of competition and economic development in the Commonwealth."

7. Provide copies of any study or studies undertaken to define and/or calculate stranded costs for any Virginia electric utility.

N/A

8. Provide any additional comments on the issues raised by Requested Actions paragraphs 2 and 3 of the LTTF Resolution.

N/A

NEM appreciates this opportunity to comment on just and reasonable net stranded costs and reiterates our commitment to working with the Commission and the other stakeholders to devise fair and effective ways to implement competitive restructuring in Virginia.

Sincerely,

Craig G. Goodman, Esq.
President
National Energy Marketers Association
3333 K Street, NW
Suite 110
Washington, DC 20007
Tel: (202) 333-3288
Fax: (202) 333-3266
Email: cgoodman@energymarketers.com
Website-www.energymarketers.com

Dated: March 20, 2003.

Attachment 8

STAFF'S E-MAIL DATED APRIL 02, 2003 AND WORK GROUP PARTICIPANT RESPONSES

From: Susan Larsen
Sent: Wednesday, April 02, 2003 10:28 AM
To: Anthony Gambardella; August Wallmeyer; Barry Thomas; Cliona Robb; Craig Goodman; Cynthia Menhorn; Daniel M. Walker; David Wagner; Edward Flippen; Edward Petrini; Eric Matheson; Frann Francis; Glenn Simpson; H. Master; Irene Leech; Jack Greenhalgh; James Kimball; John Pirko; John R. Howells; Karen Bell; Kenneth Hyrwitz; Meade Browder; Michael Kaufmann; Michael Swider; Michelle Gunzburger; Paul Hilton; R.L. Terpenny; Ransome Owan; Robert Omberg; Robert Sloan; Stacey Rantala; Taff Tschamler; Telemac Chryssikos; Thomas Kinnane; Tom Nicholson; William Thomas
Subject: Stranded Costs Work Group

Thank you to all those that participated in yesterday's work group meeting. Our next two meetings are scheduled as follows:

Monday, April 7, 9am - 1pm
Monday, April 21, 9am - 1pm
We will continue to meet in the Training Room on the 3rd floor of the Commission's office building.

Staff met yesterday afternoon to discuss definitions of stranded costs and net just and reasonable stranded costs. We decided to use the definition set forth in the Attorney General's comments as a basis. This definition is general enough to encompass a variety of stranded cost components. It provides a clear simple definition that emphasizes an essential point, that stranded costs should be a means to account for lost revenues of an incumbent electric utility operating in a competitive environment, to the extent such losses can be attributed to competition.

Stranded Costs - Stranded Costs are a utility's lost revenues arising from electric generation-related costs that become unrecoverable due to restructuring and retail competition.

Net Just and Reasonable Stranded Costs - Net Just and Reasonable Stranded Costs are a utility's lost revenues arising from prudently incurred, verifiable and non-mitagable electric generation-related costs that become unrecoverable due to restructuring and retail competition.

1. Please provide comments on the above definitions by close of business Thursday. Include a discussion of why you support or oppose each definition. If you oppose the definition please include the definitions your organization supports and a full explantion of why it is appropropriate.

2. Provide a list of all components of net just and reasonable stranded costs.

Susan Larsen
Deputy Director
Public Utility Accounting
Virginia State Corporation Commission
Ph. (804)371-9729
Fx. (804)371-9447
sdlarsen@scc.state.va.us

Dominion Virginia Power's Response – April 3, 2003

1. Stranded Costs – Dominion Virginia Power ("Dominion") believes that the Attorney General's definition of stranded costs is essentially the same as Dominion's definition. Dominion therefore does not object to such definition.

   Net Just and Reasonable Stranded Costs – The proposed definition of "Net Just and Reasonable Stranded Costs" does not reflect how the Restructuring Act is implemented and, further, does not address the "netting." Implementation of the Act produces "Net Just and Reasonable Stranded Costs" since they are the result of the methodology required by the General Assembly in the Act. Thus, the definition is: "'Net Just and Reasonable Stranded Costs' are the result of the methodology required by the Restructuring Act." Given that they are the result of methodology, however, further definition is not needed.

   The composite unbundled generation rates approved by the Commission in PUE-2000-00584 include fossil, hydro, and nuclear assets, as well as Dominion's purchases from NUGs. Use of the composite unbundled generation rate thus yields the same result as if the Commission independently compared each resource's cost component to the projected market price, and then netted the resultant positive and negative wires charges when computing the weighted average overall wires charge. If the Commission approves Dominion's unbundled generation rates – as it has – and it approves Dominion's wires charges – and it does – those rates and charges are "just and reasonable" as a matter of law.

2. Components of Net Just and Reasonable Stranded Costs – Generically speaking, stranded costs would include stranded generation costs, generation-related regulatory assets, and

transition costs. Transition costs include costs associated with customer choice implementation, such as hardware and software, employee training, and consumer education programs. The Act, however, does not provide for the recovery of transition costs except to the extent they can be recovered in capped rates.

#157061v3

From: Pirko, John A. [mailto:JPirko@LECLAIRRYAN.com]
Sent: Friday, April 04, 2003 12:09 PM
To: Susan Larsen
Cc: 'Omberg, Rob'; 'Walker, Dan'; 'Kimball, James'
Subject: Stranded Costs

Below is the Cooperatives' response to your e-mail offering definitions of the terms "stranded costs" and "just and reasonable net stranded costs." Sorry we could not get the response to you by COB yesterday.

Have a good weekend. See you Monday morning.

1. The Cooperatives do not support the definitions of "stranded costs" and "just and reasonable net stranded costs" proposed by Commission Staff in Susan Larsen's April 2, 2003, e-mail message. The Cooperatives oppose these definitions because they are not consistent with the provisions of the Restructuring Act. The only specific elements provided by the Act are how stranded costs may be recovered (capped rates or wires charges) and how wires charges are determined. In order to accurately derive definitions for these terms from the Act and keep the definitions consistent with the provisions of the Act, the means of quantifying such costs and the method of recovery should be considered essential elements of the definitions.

Based on the work group discussions and prior statements made by the Cooperatives, the Cooperatives offer the following definitions:

Stranded costs are an incumbent utility's lost electric generation-related revenues recoverable under traditional cost-of-service regulation but not recoverable in a competitive electric generation market, measured by the difference between the utility's generation-related costs while regulated (subject to fuel adjustments) and the market-based generation-related costs determined annually by the Commission, and recovered through capped rates or wires charges.

Just and reasonable net stranded costs are an incumbent utility's net loss in electric generation-related revenues recoverable under traditional cost-of-service regulation but not recoverable in a competitive electric generation market, measured by the net difference between the utility's reasonably and prudently incurred generation-related costs while regulated (subject to fuel adjustments), and the market-based generation-related costs determined annually by the Commission, and recovered through capped rates or wires charges.

These definitions are appropriate because they quantify the stranded costs and describe the method for their recovery.

2. Regarding the components of stranded costs, in their Response to the Commission Inquiries the Cooperatives listed:

(1) net generation plant investments and costs attributable to investment in generation plant and related facilities (including transmission interconnection costs);

(2) projected nuclear plant decommissioning costs, spent nuclear fuel disposal costs and projected retirement costs of non-nuclear plants;

(3) costs attributable to purchase power contracts;

(4) regulatory assets (deferred expenses authorized by a regulatory agency); and

(5) other similar or related costs determined by the Commission.

Just and reasonable net stranded costs would include the net amount of any such reasonably and prudently incurred stranded costs.

John A. Pirko
LeClair Ryan
A Professional Corporation
Attorneys at Law
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(fax)

COMMENTS OF AEP – STRANDED COST DEFINITIONS

1. In response to the Staff's proposed definitions (first question in the electronic mail message of April 2, 2003), the following definitions of "stranded costs" and "just and reasonable net stranded costs" are consistent with the intent and language of the Virginia Electric Utility Restructuring Act:

STRANDED COSTS refer to an incumbent electric utility's costs that are unrecoverable due to restructuring and retail competition.

JUST AND REASONABLE NET STRANDED COSTS refer to an incumbent electric utility's prudently incurred and verifiable Stranded Costs, the mitigation of which is beyond the control of such incumbent electric utility.

2. In response to the Staff's second question, AEP set forth four components of stranded cost in its responses of March 21, 2003 to the Commission's questions 1 and 2. Those components are: generation assets, purchased power contracts, generation-related regulatory assets, and transition costs.

State Corporation Commission

of Virginia

In the matter of developing	*	
consensus recommendations	*	Case No. PUE- 2003-00062
on stranded costs	*	

<u>Comments by Allegheny Power</u>

The Potomac Edison Company dba Allegheny Power ("AP" or "the Company") would like to provide the following comments in response to the Commission's Staff April 2, 2003 email requesting input on the following issues: (1) proposed definitions for "Stranded Costs" and "Net Just and Reasonable Stranded Costs," and (2) a list of all components of net just and reasonable stranded costs.

Staff's Proposed Definitions
Staff requested input on the following proposed definitions:

> *1) Stranded Costs - Stranded Costs are a utility's lost revenues arising from electric generation-related costs that become unrecoverable due to restructuring and retail competition.*

AP believes that the definition above begins to define the stranded costs but does not include the other cost components related to the move to retail competition. As a result, AP proposes the following definition:

> *Stranded Costs - Stranded Costs are the utility's lost generation revenues, transition costs and generation related net regulatory assets that become unrecoverable as a result of restructuring and the transition to retail competition.*

> *2) Net Just and Reasonable Stranded Costs - Net Just and Reasonable Stranded Costs are a utility's lost revenues arising from prudently incurred, verifiable and non-mitagable electric generation-related costs that become unrecoverable due to restructuring and retail competition.*

AP believes the definition above should be changed to reflect the cost components in 1) above.

2) *Net Just and Reasonable Stranded Costs - Net Just and Reasonable Stranded Costs are a utility's lost revenues arising from prudently incurred, verifiable and non-mitagable electric generation-related costs, transition costs and regulatory assets that become unrecoverable due to restructuring and retail competition.*

List of Components of Net Just and Reasonable Stranded Costs
Staff requested work group participants to provide a list of all components of net, just and reasonable stranded costs. AP offers the following suggested components (for a more detailed description please see responses 1 and 2 of the eight questions concerning stranded costs):

1. Generation-Related Assets - Losses in the economic value of an incumbent's investments and obligations related to electric generation supply that resulted from deregulation. This would also include devaluation in generation assets.
2. PURPA Contracts – Excess of purchase price over market price.
3. Transition Costs - Costs that would not have been incurred by the utility but for the adoption of restructuring legislation may also be labeled as stranded costs. Examples of potential transition costs not recovered through existing rates are consumer education costs, modifications of billing systems to accommodate new billing procedures, expanded customer service facilities, revisions to metering processes necessitated by customer choice, and costs of joining or establishing an RTO.
4. Generation-Related Deferred Costs and Regulatory Assets - If the utility has deferred costs or other deferred liabilities that will not be collected under a restructured environment then these costs that have been paid for but not yet collected would be a stranded cost.

Although AP does not have a wires charge, AP appreciates the opportunity to offer its views on this subject matter. The Company looks forward to working with Staff and other interested parties to develop consensus recommendations on this very important issue.

From: August Wallmeyer [augie@wallmeyer.nasmail.net]
Sent: Thursday, April 03, 2003 2:33 PM
To: Susan Larsen
Subject: Re: Stranded Costs Work Group

Ken Hurwitz and I, on behalf of VIPP, agree with the gist of the two definitions you suggest, and do not have changes to offer at this time.

Augie Wallmeyer

August Wallmeyer
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Richmond, VA 23219

Tel. (804) 788-4931
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----- Original Message -----
From: "Susan Larsen" <SdLarsen@scc.state.va.us>
To: "Anthony Gambardella" <agambard@woodsrogers.com>; "August Wallmeyer" <augie@wallmeyer.nasmail.net>; "Barry Thomas" <bthomas@aep.com>; "Cliona Robb" <crobb@cblaw.com>; "Craig Goodman" <cgoodman@energymarketers.com>; "Cynthia Menhorn" <cmenhor@alleghenyenergy.com>; "Daniel M. Walker" <dwalker@odec.com>; "David Wagner" <dw7222@aol.com>; "Edward Flippen" <eflippen@mcguirewoods.com>; "Edward Petrini" <epetrini@cblaw.com>; "Eric Matheson" <eric.matheson@constellation.com>; "Frann Francis" <ffrancis@aoba-metro.org>; "Glenn Simpson" <simpson@pepcoenergy.com>; "H. Master" <hmaster@energymarketers.com>; "Irene Leech" <ileech@vt.edu>; "Jack Greenhalgh" <jack@jackgreenhalgh.com>; "James Kimball" <jkimball@odec.com>; "John Pirko" <jpirko@leclairryan.com>; "John R. Howells" <jhowell@alleghenyenergy.com>; "Karen Bell" <karen_bell@dom.com>; "Kenneth Hyrwitz" <ken.hurwitz@haynesboone.com>; "Meade Browder" <mbrowder@oag.state.va.us>; "Michael Kaufmann" <michaelkaufmann@dwt.com>; "Michael Swider" <mswider@sel.com>; "Michelle Gunzburger" <mgunzbu@alleghenyenergy.com>; "Paul Hilton" <paul_hilton@dom.com>; "R.L. Terpenny" <tmanager@christiansburg.org>; "Ransome Owan" <ransomeowan@wges.com>; "Robert Omberg" <romberg@odec.com>; "Robert Sloan" <rsloan@alleghenyenergy.com>; "Stacey Rantala" <srantala@energymarketers.com>; "Taff Tschamler" <ttschamler@xenergy.com>; "Telemac Chryssikos" <macchryssikos@wges.com>; "Thomas Kinnane" <tkinnane@kinnanelaw.com>; "Tom Nicholson" <tnicholson@williamsmullen.com>; "William Thomas" <wthomas@reedsmith.com>
Sent: Wednesday, April 02, 2003 10:28 AM
Subject: Stranded Costs Work Group

\>
\> Thank you to all those that participated in yesterday's work group meeting.
\> Our next two meetings are scheduled as follows:
\>
\> Monday, April 7, 9am - 1pm
\> Monday, April 21, 9am - 1pm
\> We will continue to meet in the Training Room on the 3rd floor of the

> Commission's office building.
>
> Staff met yesterday afternoon to discuss definitions of stranded costs and
> net just and reasonable stranded costs. We decided to use the definition
> set forth in the Attorney General's comments as a basis. This definition
is
> general enough to encompass a variety of stranded cost components. It
> provides a clear simple definition that emphasizes an essential point,
that
> stranded costs should be a means to account for lost revenues of an
> incumbent electric utility operating in a competitive environment, to the
> extent such losses can be attributed to competition.
>
>
> Stranded Costs - Stranded Costs are a utility's lost revenues arising from
> electric generation-related costs that become unrecoverable due to
> restructuring and retail competition.
>
> Net Just and Reasonable Stranded Costs - Net Just and Reasonable Stranded
> Costs are a utility's lost revenues arising from prudently incurred,
> verifiable and non-mitagable electric generation-related costs that become
> unrecoverable due to restructuring and retail competition.
>
> 1. Please provide comments on the above definitions by close of business
> Thursday. Include a discussion of why you support or oppose each
> definition. If you oppose the definition please include the definitions
> your organization supports and a full explantion of why it is
> appropropriate.
>
> 2. Provide a list of all components of net just and reasonable stranded
> costs.
>
> Susan Larsen
> Deputy Director
> Public Utility Accounting
> Virginia State Corporation Commission
> Ph. (804)371-9729
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>
>

From: Browder, Meade [mailto:MBrowder@oag.state.va.us]
Sent: Friday, April 04, 2003 2:11 PM
To: Susan Larsen
Subject: RE: Stranded Costs Work Group

Sue-

We've decided to not submit anything further at this time. As the definition identified by Staff for stranded costs is the one we set forth, obviously we support it for the reasons noted in our initial responses.

Meade

>C. Meade Browder Jr.
>Sr. Assistant Attorney General
>Insurance & Utilities Regulatory Section
>Office of the Attorney General
>900 East Main Street
>Richmond, Virginia 23219
>(804) 786-7373 - phone
>(804) 371-2086 - fax
>mbrowder@oag.state.va.us

Susan:

Here is a quick response to your e-mail of yesterday concerning stranded costs.

1. We would disagree with the suggested definition of stranded costs. By defining stranded costs in terms of a "utility's lost revenues," it appears to confuse costs with revenues. In addition, the definition makes no reference to the utility's net investment in generation assets, which, if unrecovered or unrecoverable as a result of retail competition, represents a "stranded cost." It is not the revenues collected from a generating asset that are "stranded"; it is the amount of the net investment in the asset that potentially is left "stranded" by retail competition. The same concern applies to both the definition of "stranded cost" and the definition of "just and reasonable net stranded cost."

The definition of "just and reasonable net stranded costs" represents a good start by including concepts of "prudence," mitigation ("mitigable"), verification, and causation ("attributed"). It is too limited, however, in that it does not include the concept of "netting" of stranded costs and benefits or the concept of "just and reasonable" costs – *i.e.*, the broader concept of including only the types of costs that would be included in a utility's cost of service when setting "just and reasonable" rates.

Our suggested definitions of both phrases, as included in our prior comments, which were filed on March 21, are as follows:

> Stranded costs may be defined as booked, embedded generation-related costs that are not recovered or recoverable by an incumbent electric utility as a result of retail customer choice, as provided in Virginia's Electric Utility Restructuring Act ("Restructuring Act"). Stranded cost components include unrecovered and unrecoverable costs associated with each of the utility's generating units, purchased power contracts (including any non-utility generation, or "NUG," contracts), generation-related regulatory assets, and nuclear decommissioning costs (if applicable). A generating unit's stranded costs may not exceed its remaining net book value.

2. Our prior comments, as filed on March 21, included a list of the components of "just and reasonable net stranded costs," as follows:

> Generation-related components of such costs [*i.e.*, just and reasonable net stranded costs"] include those identified in response to question 1 – *i.e.*, "just and reasonable net stranded costs" associated with the incumbent electric utility's generation units, purchased power contracts (including NUG contracts), generation-related regulatory assets, and nuclear decommissioning (if applicable). "Just and reasonable" net stranded costs include net stranded costs whose recovery would be permitted under traditional ratemaking principles designed to produce "just and reasonable," cost-based rates to utility customers.

From: Eric Matheson [mathesone@millenianet.com]

Sent: Friday, April 04, 2003 6:15 AM

To: Eric Matheson; Susan Larsen

Subject: VA Strand Cost definitions - Comments by

Stranded Costs - Stranded Costs are a utility's lost revenues arising from electric generation-related costs that become unrecoverable due to restructuring and retail competition.

Constellation NewEnergy, Inc. (NewEnergy) proposes that the definition be changed as follows, by drawing on the definitions of Richard Williams of the VSCC and the Attorney General:

Stranded Costs are the net loss in economic value arising from electric generation-related costs that become unrecoverable due to restructuring and retail competition.

Any reference to "lost revenues" may imply that utilities are guaranteed some sort of revenue stream into perpetuity without regard to future fuel costs, technological change, efficiency improvements, changes in the generation portfolios, generation asset life, expiration of power purchase contracts, and other factors. This notion of guaranteed revenues is why the current wires charge calculations do not permit competition in the base case, and why the LTTF and the Commission have committed themselves to examine actual stranded costs. A more general definition (net loss in economic value), as provided by Richard Williams in his presentation to the Task Force will provide a more flexible and broad definition from which to commence discussions on stranded costs.

Net Just and Reasonable Stranded Costs - Net Just and Reasonable Stranded Costs are a utility's lost revenues arising from prudently incurred, verifiable and non-mitagable electric generation-related costs that become unrecoverable due to restructuring and retail competition.

Consistent with the above adjustment to the stranded cost definition, NewEnergy recommends that the definition of Net Just and Reasonable Stranded Costs be adjusted as follows:

Net Just and Reasonable Stranded Costs are a utilities net loss in economic value of prudently incurred, verifiable and non-mitagable electric generation-related costs that become unrecoverable due to restructuring and retail competition.

Constellation NewEnergy, Inc. will discuss its positions on the components of net stranded cost at the meeting on Monday.

STAFF'S E-MAIL DATED APRIL 10, 2003 AND WORK GROUP PARTICIPANT RESPONSES

Attachment 9

From: Susan Larsen
Sent: Thursday, April 10, 2003 10:45 AM
To: Anthony Gambardella; August Wallmeyer; Barry Thomas; Cliona Robb; Craig Goodman; Cynthia Menhorn; Daniel M. Walker; David Wagner; Edward Flippen; Edward Petrini; Eric Matheson; Frank Munyan; Frann Francis; Glenn Simpson; H. Master; Irene Leech; Jack Greenhalgh; James Kimball; John Pirko; John R. Howells; Karen Bell; Kenneth Hyrwitz; Lex Bailey; Meade Browder; Michael Kaufmann; Michael Swider; Michelle Gunzburger; Paul Hilton; R.L. Terpenny; Ransome Owan; Robert Omberg; Robert Sloan; Stacey Rantala; Taff Tschamler; Telemac Chryssikos; Thomas Kinnane; Tom Nicholson; William Thomas
Subject: Determination of Stranded Costs over/under recoveries - Proposed Conceptual Models

Good morning:

At Monday's meeting we moved from a discussion of definitions to a discussion of methodologies. We identified two conceptual models that can be discussed and developed in the coming weeks. We asked all parties to state their position in regard to each model and to comment on the pros and cons of each model. A brief summary of each proposal is provided below.

Please provide comments by April 16, 2003.
All comments will be posted to the Economics and Finance section of the Commission's website.

Our next meeting is April 21, 2003, 9 a.m. in the Commission's 3rd floor training room.

<u>Proposal 1 as summarized in Dominion Virginia Power's March 21, 2003 comments, page 5:</u>

The methodology for calculating "just and reasonable net stranded costs" requires a utility to determine whether there is over- or under-recovery of stranded costs collected through the wires charges from switching customers. A company can compare the revenue actually collected from customers via the wires charges based on projected market prices to the revenue that would have resulted had wires charges been based on the actual market prices experienced during that year. If the revenue collected through the wires charges was greater than the revenue that would have resulted had the actual market price been correctly predicted, the wires charges were set too high, resulting in an over-recovery. If the contrary is the case then there is under-recovery.

<u>Proposal 2 as summarized by Staff:</u>

To calculate just and reasonable net stranded costs compare asset values based on net present value cash flows that arise from remaining in a regulated market (cost plus a fair return) to the net present value cash flows that arise in a competitive market (over the life of the assets). From this amount subtract recoveries via capped rates (to the extent capped rates exceed actual costs including a fair return) and wires charges to determine the over- or under-recovery of just and reasonable net stranded costs.

Response of Dominion Virginia Power to the "Generalized Framework"
Presentation by Howard Spinner on April 7, 2003

On April 10, 2003, the Commission Staff summarized as "Proposal 2" the proposal that Howard Spinner presented to the work group on April 7, 2003. With all respect to the Staff, Dominion Virginia Power does not believe the summary adequately captures the complexity of Mr. Spinner's methodology. The unknown factors and speculation that would be involved in the 30 plus year projection required by his proposal are mind-boggling. Mr. Spinner understands this. In addressing the effort to project market prices for one year in the pilot programs, he testified: "While it is relatively straight forward to determine the capped generation rates...the determination of market prices for generation is much more difficult. In fact, it is difficult to determine the market value of a given quantity of electric power during an historical period, much less the future." *In the matter of considering an electricity retail access pilot program*, Case No. PUE-1998-00814, Prefiled Testimony of Howard M. Spinner, 28-29.

What Mr. Spinner presented to the work group was a conceptual "general framework" for monitoring stranded costs "consistent with the Act." Specifically, Mr. Spinner referred to § 56-595.C.(iii) as the authority for his proposal. He admitted, however, that his proposed methodology was conceived without regard to the legislative background of the Restructuring Act.

As Dominion Virginia Power understands Mr. Spinner's proposal, his methodology requires complex calculations and thousands of data inputs and assumptions. First, market prices would be projected for the remaining economic lives of a utility's generating assets, which would be more than 30 years in some cases. During the time period prior to July 1, 2007, the difference between capped rates and these projected market prices would be considered stranded costs, or stranded benefits, depending on whether such market prices were below, or above, capped rates.

After that date, the relevant difference would be the amount between projected market prices and a utility's projected *generating costs*, rather than capped rates, since capped rates would no longer be in effect. Again, at any point in time, these generating costs might be above projected market prices, producing stranded costs, or below market, yielding stranded benefits. Second, the present value of a utility's projected stranded costs would be compared to the present value of any projected stranded benefits during the study period to yield a net stranded cost or benefit amount. Third, the difference between a utility's capped rates[1] and what its estimated annual cost of service would have been had the Restructuring Act not been adopted would be estimated to ascertain "recovered" stranded costs. This assumes, of course, that such estimated cost of service was determined to be below, not above, capped rates. Finally, the amount of "recovered" stranded costs would be compared to the "net stranded cost/benefit" amount to determine whether stranded costs are projected to be over- or under-recovered during the capped rate period.

Mr. Spinner's proposed methodology would require the determination of thousands of important data inputs and assumptions regarding the following:

1. the study time horizon, remaining economic lives, and contract terms for current generating resources;

2. the following statistics on each utility's generating resources:
   - remaining economic lives for a regulated and market environment
   - capacity factors derived from dispatch requirements under regulated and market scenarios;

[1] Although Mr. Spinner did not discuss in detail the role of wires charges in his methodology, Dominion Virginia Power assumes he would agree that wires charges would supplant the above-market portion of capped rates for those customers who "shop" during the capped rate period. Under his methodology, wires charges are thus simply a means to ensure that utilities are financially indifferent as to whether customers switch to a CSP or continue to pay capped rates.

3. an estimate of market prices over the period of a utility's current generating facilities' lives and power purchased contract terms or the study time horizon, if different;

4. an estimate of the retail rate for default service after July 1, 2007, (if less than market price in (3));

5. a discount rate for the required present value calculations;

6. what each utility's estimated annual cost of service and fair rate of return would have been from 1999 until July 1, 2007, assuming the Restructuring Act had not been adopted; and

7. after July 1, 2007, a utility's estimated capital and operating costs of each of its generating assets for their remaining economic lives.

In summary, such projection and assumptions would supposedly show an amount equal to the present value of a utility's above-market (stranded) costs, compared to the present value of any stranded benefits, less any amounts recovered under capped rates above a utility's assumed cost of service from 1999 until July 1, 2007. The latter calculation (amounts recovered under capped rates above a utility's assumed cost of service) are referred to by Mr. Spinner as the "Virginia twist," i.e., a different analysis than those found in stranded cost methodologies used or proposed in other jurisdictions.

Mr. Spinner was candid about his proposed study. He admitted his methodology would be "fraught with controversy every step of the way" and "very, very difficult." The difficulties, of course, are well known. The Commission has observed that "long-term market prices of a sensitive, non-storable, essential product with highly volatile, weather-sensitive demand cannot be estimated within the bounds of reasonable accuracy." Appendix A, p. 1.[2] The Commission has also noted that in some cases, projections would have to extend decades into the future because some "existing utility assets may have a remaining useful life of over 30 years." *Id.*

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[2] "Appendix A" is attached to Dominion Virginia Power's response to the Commission's Order Establishing Proceeding dated March 3, 2003.

"Factors such as potential life extensions of assets and new environmental upgrades would further complicate the calculations," according to the Commission. *Id.*

Another complicating factor would be an incumbent utility's potential role in providing default service. For example, there is the question of whether Dominion Virginia Power's generation will be required to "back up" other default suppliers and, thus, will be dedicated to Virginia. If the answer is yes, this factor will have a significant impact on any stranded cost projections using the Spinner methodology; callable, non-firm projected market prices will be much different than non-recallable, firm power prices.

Other Commission statements further illustrate why Mr. Spinner's method would, as he said, be "very, very difficult." In comments made to the SJR 91 subcommittee on May 26, 1998, Richard Williams, Director of Economics and Finance at the Commission, stated that "I don't think I have to tell you the number of assumptions that would have to be involved in each of those calculations . . .. A change in the projected market price of 15% up or down could either eliminate or double the stranded cost calculation." Attachment, p. 1.[3] He also said that "I hope you don't mind my making a brief editorial comment, but policy implementation which locks in stranded cost recovery based on long-range forecasts and market prices under a market structure that does not currently exist could prove disastrous." *Id.*

During the debate prior to adoption of the Restructuring Act, the Commission implicitly rejected Mr. Spinner's type of methodology by stressing the importance of flexibility. It stated that "[i]f the General Assembly decides that at least some portion of stranded costs should be recoverable, we suggest a legislative approach to the determination of recovery of such costs that is specifically aimed at maintaining reasonable and necessary *flexibility* with respect to policy implementation and administration. We believe that this *flexibility* is critical to serving the public interest of Virginia in that such a process entails substantial complexity and uncertainty, poses significant public impacts, and must address the unique circumstances of each utility . . . (emphasis added)." . . . "It is essential that rigidity not be incorporated in one component of the transition process that may unintentionally undermine the ultimate objective." *Id.* at 2-3.

A review of the development of the Restructuring Act in general and the stranded cost issue in particular shows that the General Assembly rejected approaches similar to Mr. Spinner's methodology for the same reasons the Commission recommended against them. Both the Commission and the General Assembly refused to embrace long-term, forward-looking projections and asset evaluations as a means of quantifying stranded costs. Instead, the Act incorporates the "lost revenue" approach discussed in Dominion Virginia Power's response to the Commission's Order Establishing Proceeding. Exercises such as those proposed by Mr. Spinner were labeled "a recipe for disaster" that could "unintentionally undermine the ultimate objective." Appendix A, p. 1. While counseling against rigid, up-front calculations, the Commission consistently held that stranded cost recovery mechanisms must be marked by "reasonable and necessary flexibility." *Id.* at 2.

Thus, the Commission has ruled that the "lost revenue" principle that eventually became the foundation of the Restructuring Act's stranded cost recovery provisions is designed to preserve revenue neutrality for incumbents during the transition period. *In the matter of considering requirements related to wires charges pursuant to the Virginia Electric Utility Restructuring Act*, Case No. PUE-2001-00306, Final Order, 2002 Va. PUC LEXIS 397, *9 n.5 (Oct. 11, 2002); *In the matter of considering requirements related to wires charges pursuant to the Virginia Electric Utility Restructuring Act*, Case No. PUE-2001-00306, Final Order, 2001 Va. PUC LEXIS 304, *29 (Nov. 19, 2001) The Commission has also stated ". . . wires charges

[3] The "Attachment" is attached to "Appendix A."

serve as a 'proxy' on a utility by utility basis, of stranded costs. Therefore, no actual determination of stranded costs is necessary . . .." *Application of Northern Virginia Electric Cooperative, for review of tariffs and terms and conditions of service*, PUE-2002-00086, Final Order, 2002 Va. PUC LEXIS 293, *5 n.3 (June 18, 2002).

In short, to the extent Dominion Virginia Power's unbundled generation rates approved by the Commission in PUE-2000-00587 exceed Commission-approved projected market prices, the Act provides for Commission-approved wires charges for customers who purchase electricity from CSPs. During the same period, customers who continue to receive electricity from their incumbent utility pay capped rates. Any such wires charges collected serve to prevent the utility from experiencing lost revenues due to a customer's decision to switch to a CSP. In addition, funds available from capped rates during the transition period may permit a utility to mitigate its above-market costs until July 1, 2007. The amount and timing of such mitigation is the "flexibility" that each utility has under the Act and is consistent with the Commission's recommendation of a "flexible" approach. Attachment, p. 2.

In the final analysis, whether a utility has above-market costs as of July 1, 2007, will depend upon a host of factors. In particular, the answer hinges on the extent of the utility's mitigation during the transition period and on market prices as of July 1, 2007. If the utility is not at market on July 1, 2007, then it has no further right to revenue neutrality, i.e., its generation-related revenues will be determined by the market. If desired by the LTTF, until July 1, 2007, each utility could report annually any amounts collected in wires charges and the extent of its mitigation of above-market costs. Such reporting would allow the LTTF to monitor recovery of stranded costs and the mitigation of above market costs in accordance with § 56-595.

The methodology proposed by Mr. Spinner is not consistent with the Act. Indeed, the notion that a utility's revenue requirement might be determined on an annual basis during the transition period, except at the request of the utility, was never proposed during the years of debate leading up to the Restructuring Act. In fact, the Act compels just the opposite conclusion, as several provisions make clear. For example, except for Dominion Virginia Power, every utility had the option of seeking a "going-in" rate case to have its capped rate levels fixed by the Commission. Significantly, no other party, not even the Commission on its own motion, was permitted under the Act to initiate such a rate case, even if the existing rates were believed to be too high. Second, once capped rates have been established, Code § 56-582 provides only limited means by which those rates may be changed during the transition period: (a) rates may reflect the costs of fuel and purchased power; (b) changes in tax laws can be recognized; (c) financial distress of a utility beyond its control can be remedied; and (d) if a utility's petition to terminate capped rates after January 1, 2004 is rejected, then utilities other than Dominion Virginia Power may request a one-time change in the non-generation components of their rates. Again, except for the fuel and tax provisions, the other means of changing capped rates during the transition period are clearly options held by the utilities, not other parties.[4]

The multi-year rate case type calculation required as the key ingredient of Mr. Spinner's methodology is thus an afterthought with no legal basis. It also lacks any practical underpinnings, as demonstrated by the difficulties and controversies that would be involved in trying to conduct such a proceeding using a "test period" span of seven and a half years and

[4] The provision that permits rate changes to relieve financial distress of a utility quite clearly means that no entity is permitted under the Act to seek changes to rates it believes to be too generous. A key attraction of Mr. Spinner's proposed methodology for some members of the work group appears to be the belief that, if a utility's revenue requirement for the 1999 to 2007 transition period is estimated, it will show that capped rates were, or might be, too high, however that concept might be defined, during that period. However, there simply is no authority under the Act for even raising that question.

attempting to determine, retroactively in large measure, what a utility's revenue requirement would have been but for capped rates and stranded cost mitigation efforts. This proposal comes, in Dominion Virginia Power's case, *after* spending hundreds of millions of dollars on mitigation measures and making hundreds of millions of dollars in new investments.

Mr. Spinner's methodology also ignores the fact that the Commission has refused to accept the complexities and uncertainties of projected test periods in the past. In rejecting even a one-year projection for a Virginia Power application filed on February 15, 1978, the Commission stated that "...in order to use any level of projected expenditures, one must first evaluate the projected date against identifiable and acceptable standards." *Application of Virginia Electric and Power Company, for an increase in rates*, Case No. 19960, Opinion and Final Order, 1979 S.C.C. Ann. Rep. 164, 167 (Mar. 19, 1979). The Commission further stated that "...when presenting projected data, utilities must present the material so as to permit the Staff and other parties to trace projections back to their historical source. All assumptions and changes in activity levels should be quantified and supported to provide a 'link' between the historic test year and the projected data." *Id.* at 168.

Mr. Spinner's methodology may be easy to describe in theory, but, as the Commission has made clear, a 30-year or longer study cannot produce any calculations with reasonable certainty. As we have learned the hard way in recent years, even short-term projections by Wall Street and others have proven to be "pure fantasy." The idea that the working group--or anyone else--can project market prices, capital and operating costs, and make accurate assumptions about generating plant operations for 30 plus years, is an illusion. Mr. Williams put it best: it is a "potential for a public policy disaster . . .." Attachment, p. 3.

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April 18, 2003

Via electronic mail

Susan D. Larsen, Deputy Director
Division of Public Utility Accounting
State Corporation Commission
1300 East Main Street
Richmond, VA 23218-1197

Re: *Commonwealth of Virginia,* ex rel. *State Corporation Commission In the Matter of Developing Consensus Recommendations on Stranded Costs Case No. PUE-2003-00062*

Dear Ms. Larsen:

As requested at the conclusion of the April 7, 2003, meeting of the Stranded Cost Working Group, the following comments on the two proposed methodologies for monitoring stranded cost recovery are submitted on behalf of Virginia's electric cooperatives.

As a general matter, the Cooperatives support the Dominion Virginia Power proposal, which states:

> The methodology for calculating "just and reasonable net stranded costs" requires a utility to determine (1) whether there is over- or under-recovery of stranded costs collected through the wires charges from switching customers, and (2) the amounts it has expended from funds available under capped rates to mitigate potential stranded costs. Under (1) a company can compare the revenue actually collected from customers via the wires charges based on projected market prices to the revenue that would have resulted had wires charges been based on the actual market price experienced that year. If the revenue collected through the wires charges was greater than the revenue that would have resulted had the actual market price been correctly predicted, the wires charges were set too high, resulting in an over-recovery. If the contrary is the case then there is under-recovery. In any event, whether the above two measures produce an over-or under-recovery of a utility's total stranded costs cannot be finally determined until after July 1, 2007.

The Cooperatives believe this methodology is consistent with the spirit and the letter of the Restructuring Act, and that it fully accommodates the majority positions expressed by the SJR 91 Drafting Group, the subcommittee as a whole and the General Assembly. The Dominion

Virginia Power approach provides for a year-to-year review of the stranded costs recovered from those customers that switch and eliminates estimation and guesswork. Other benefits of this proposed method are that it is transparent, easy to administer and easily understood. In addition, this method minimizes the financial risk to the incumbent electric utilities and measures the cost impact on the customers that created stranded costs by changing power suppliers. Finally, this proposed method would accommodate mitigation by the incumbent utility to help minimize over- or under-recovery of stranded costs.

In comparison, the proposal presented by Staff at the April 7, 2003, meeting is not consistent with the Restructuring Act and offers few comparable benefits. Staff's proposal is:

> To calculate just and reasonable net stranded costs compare asset values based on net present value cash flows that arise from remaining in a regulated market (cost plus a fair return) to the net present value cash flows that arise in a competitive market (over the life of the assets). From this amount subtract recoveries via capped rates (to the extent capped rates exceed actual costs including a fair return) and wires charges to determine the over-or under-recovery of just and reasonable net stranded costs.

The Cooperatives do not endorse this proposed model. Staff's proposed methodology is not consistent with the spirit and the letter of the Restructuring Act, and implementation would require that many of the tasks and analyses specifically rejected by the SJR 91 Drafting Group, the subcommittee and the General Assembly be undertaken now, well into scheduled period for the transition to retail access. The Staff method would require a forecast of asset value as part of the competitive market analysis, an approach not adopted under the Restructuring Act. Further, before implementing Staff's proposal, some agreement would have to be achieved regarding the methodology for forecasting the future market and price, the overall time period to be covered by the analysis and the proper discount rate to use over the period of the forecast.

As noted by the Commission Staff during the discussion before the Stranded Costs and Related Issues Task Force, stranded cost recovery based on long-term market projections could be disastrous. Staff's proposal requires both a re-evaluation of what has occurred in the past few years and long-term future projections. The Cooperatives cannot support such an approach.

Thank you for your attention to these comments. The Cooperatives appreciate the opportunity to present these preliminary views on the proposals discussed at the April 7, 2003, meeting and look forward to further participation with the Stranded Cost Working Group.

Sincerely,

John A. Pirko

John A. Pirko

JAP/stf
cc: Virginia Distribution Cooperative Managers
SCC Division of Economics and Finance

AEP
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April 17, 2003

Ms. Susan D. Larsen, Deputy Director
Division of Public Accounting
State Corporation Commission
1300 East Main Street
Richmond, VA 23219

Re: Stranded Cost Working Group Comments

Dear Ms. Larsen:

At the meeting of the Stranded Cost Working Group on April 7, 2003, two potential methods for monitoring stranded cost recovery were discussed. First, a methodology described in the written comments of Dominion Virginia Power was briefly noted. Second, Mr. Howard Spinner presented a proposed monitoring methodology ("Staff model"). You requested the participants in the meeting to provide written comments on these two methods. Appalachian Power Company ("Appalachian" or "Company") submits this letter in response to your invitation.

While the Company would support the Dominion Virginia Power stranded cost monitoring model as an approach to monitoring stranded cost recovery consistent with the Act, Appalachian continues to be concerned about the lack of development - both to date and anticipated - of a competitive retail market in Virginia and the clear implications of this condition for the LTTF's over/under-recovery assessment.

The applicable resolution of the Legislative Transition Task Force ("LTTF") requires this Working Group to develop "consensus recommendations, consistent with the provisions of the [Virginia Electric Utility Restructuring] Act … ." In the Company's view, Dominion Virginia Power's proposal is generally consistent with the framework of the Act, while the Staff model is inconsistent with the existing provisions of the Act. The Staff model would require fundamental changes in the Act and would be little different than traditional utility rate regulation.

Section 56-584 of the Act provides, in pertinent part, that "… each incumbent electric utility shall only recover its just and reasonable net stranded costs through capped rates as provided in § 56-582 or wires charges as provided in § 56-583." Section 56-595 C (iii) of the Act provides, as relevant here, for the LTTF to inquire as to "…whether the recovery of stranded costs, as provided in § 56-584, has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs . . . ." Neither of these sections says anything about the calculation of stranded costs except that the LTTF monitoring is to be consistent with § 56-584 which, in turn, requires recovery of stranded costs to be in accordance with the capped rates and wires charges sections of the Act.

The remainder of the Act avoids the necessity to make initial or periodic stranded cost projections, and the Staff of the Commission had advised the General Assembly at the time the Act was adopted that efforts to project stranded costs at the outset could result in "disaster". The correct interpretation of § 56-595 C (iii), and the Paragraph 1 of the LTTF resolution, is that the LTTF should monitor recovery of stranded costs under the existing provisions of the Act. The correct question for the Work Group to deliberate, therefore, is: Are there methodologies to monitor recovery of stranded costs which do not involve an administrative projection of stranded costs not informed by the current provisions of the Act, but which also provide the LTTF an ability to evaluate the likelihood of reasonable recovery of stranded costs?

Dominion Virginia Power has already identified one methodology that would monitor the recovery of stranded costs under the existing provisions of the Act. The Dominion Virginia Power model would monitor the accuracy of the projected market prices for electric generation consistent with the revenue neutrality principle that the Commission has already approved for estimating generation market prices for computation of wires charges. The Company does not disagree that the Dominion Virginia Power model should be considered further as a methodology consistent with the existing provisions of the Act.

The Staff model, on the other hand, assumes that the Commission would make a mid-course projection of stranded costs over the life of the relevant assets. This assumption, while not yet fully explored by the Company, is inconsistent with the existing provisions of the Act, and there is nothing in the Act that gives any guidance as to the manner in which such a projection should be made. The Staff model is, therefore, in conflict with the provisions of the Act in this respect. Legislative guidance and fundamental statutory changes would be required prior to any attempt at its implementation.

The Staff model also apparently intends that revenue from capped rates be compared to some form of an on-going cost-of-service standard and that the result could change stranded cost recovery from time to time. The effect would be that capped rates could be changed on a cost-of-service basis periodically. The provisions of the Act, however, do not contemplate adjustments to capped rates, except in the limited fashion delineated in those provisions. The fundamental concept of the Act was that incumbent electric utilities would be entitled to, and would accept the risk of, the rate levels established in the Act for a limited period of time (until July 1, 2007). The Staff model would appear to suggest critical changes in these provisions of the Act based solely on reliance on the single provision that requires monitoring of stranded cost recovery.

The Staff model could also be interpreted to operate without regard to the admonition of the Act that "positive" net stranded costs are recoverable under § 56-584 and that no wires charges should be less than zero under § 56-583. Read together, these provisions make clear that the stranded cost recovery mechanisms in the Act are not intended to permit re-argument of "negative wires charges" and related issues that have long been resolved. If the Staff model is to be further considered by the Working Group, it will reopen fundamental restructuring issues that have been resolved for several years.

The Staff model begins with stranded cost recovery methodologies considered in other jurisdictions and in other circumstances; however, those methodologies are not applicable to the Act or the current situation in Virginia. The Staff suggests that its model is similar to models involving "going-in" estimates of stranded costs for purposes of establishing a specific stranded cost recovery component. Any such component could then be continuously evaluated during any transition or market development phase. This approach was specifically rejected in Virginia. The Staff model would introduce the need to estimate stranded costs and make assumptions about a number of variables. The provisions in the current legislation established four years ago avoid the uncertainty associated with making such estimates and assumptions. In addition, there are elements of the Staff model which are simply not clear in terms of process and provisions. Even if the LTTF resolution were read as an instruction to produce stranded cost projections not contemplated by the current provisions of the Act, the Staff model would remain in conflict with important features of the Act and require significant statutory change.

There is no justification to read § 56-595 C (iii) out of context to suggest that it reverses all of the other provisions in the Act that govern stranded cost recovery, capped rates and wires charges. The Working Group should concentrate on exploring whether the Dominion Virginia Power proposal can be developed to meet the needs of the LTTF or whether other models consistent with the Act can be identified. If further consideration of the Staff model is to be undertaken, it should be made clear in the Staff report to the LTTF, from the outset, that adoption of such a model would require that fundamental changes to many aspects of the current Act be adopted by the General Assembly.

Thank you for the opportunity to present these preliminary views on the proposals discussed at the April 7 meeting, and the Company looks forward to further participation in the Working Group deliberations.

Sincerely,

Barry L. Thomas

Barry L. Thomas, Director
Regulatory Services VA/TN

BLT/cde

State Corporation Commission
of Virginia

In the matter of developing	*	
consensus recommendations	*	Case No. PUE- 2003-00062
on stranded costs	*	

Comments by The Potomac Edison Company dba Allegheny Power

<u>Preliminary Comments</u>

As part of its functional separation plan, AP executed a Memorandum of Understanding ("MOU") with Staff in which, among other things, the Company waived its right to assess a wires charge and rolled its fuel factor into base rates. The MOU was designed as a comprehensive settlement to address all issues including stranded cost recovery. Thus, AP is in a different position than the other utilities in Virginia in that its stranded cost issues have been addressed through its MOU.

The MOU executed in AP's functional separation case was designed as a complete settlement to address all issues involving stranded cost recovery. As part of the MOU AP agreed to waive its right to assess a wires charge, thereby accepting additional risk in the event customers switch to an alternative supplier. Also as part of the MOU, AP's fuel clause was rolled into base rates, with the Company accepting additional risk with respect to fuel prices. The MOU established capped rate levels for AP, and AP would recover whatever stranded costs existed through capped rates. Under these circumstances, the calculation of net stranded costs is only of academic interest to AP. But for the purposes of discussion, of the two methods under consideration AP would favor Dominion Virginia Power's proposed model.

<u>1) Comments on the Proposed NPV Model</u>

(Definition below from SCC email 4/10/03)

To calculate just and reasonable net stranded costs compare asset values based on net present value cash flows that arise from remaining in a regulated market (cost plus a fair return) to the net present value cash flows that arise in a competitive market (over the life of the assets).

From this amount subtract recoveries via capped rates (to the extent capped rates exceed actual costs including a fair return) and wires charges to determine the over- or under-recovery of just and reasonable net stranded costs.

Advantages

AP knows of no advantages to an administratively determined calculation of stranded costs that is burdensome to model and is based on numerous assumptions reflecting each utilities own view and timing of future events. And as discussed below, AP would be further burdened by the modeling and assumption difficulties brought about by the generation asset transfer in August 2000.

Disadvantages

This model would require a significant amount of resources, projections, opinions regarding pricing and environmental issues, etc.. to address the many variables and assumptions that would be necessary to prepare a point in time estimate of stranded costs or benefits of each generation unit. Due to the complexity of such a model and the limitations of a point in time estimate of future values, it is highly unlikely that the net present value result of the calculation would be meaningful.

AP has gone through restructuring proceedings in other jurisdictions that have required an estimate of stranded costs. Stranded cost issues in each of those cases was very contentious and time consuming. Depending on the assumptions made, the estimate of stranded costs could either be a benefit or cost. In the end, stranded cost issues were settled by negotiation rather than by an administratively determined model.

Following is a partial list of the many modeling assumptions that would be open to debate:

1) market prices
2) fuel prices
3) useful lives of the units
4) potential life extension of units
5) O&M costs
6) environmental costs
7) reserve margins
8) new generation technology
9) capital structure of new entrants
10) appropriate discount rate
11) availability factor of units

Dominion Virginia Power, in its Appendix A submitted with the eight questions, provides a history of the troubles with quantifying stranded costs as stated by the State Corporation Commission and its staff during the 1998 time period. The SCC and its staff rejected using an up-front determination of stranded costs at that time due to the inaccuracy of results brought about by the sensitivity of the projections and estimates used in the calculation.

In addition to these disadvantages and difficulties inherent in the proposed model's methodology for quantifying stranded costs, AP also questions the second step in the proposal that advocates using capped rate recoveries in determining over- or under- recovery of stranded costs. As stated earlier, AP waived its right to the wires charge as part of the settlement process and thus does not collect any generation revenues if customers shop. However, customers who do not shop continue to receive service from AP, and these customers pay the fair, just, and reasonable cost-based rates for this service that were established by this Commission.

Section 56-582 of the Act establishes capped rates for a period that can extend until July 1, 2007. This section provides clear guidance to the Commission concerning any rate application filed prior to January 1, 2001, directing the Commission to "give due consideration, on a forward-looking basis, to the justness and reasonableness of rates to be effective for a period of time ending as late as July 1, 2007." This is not a short period of time. At this point in the year 2003, AP questions the practical value of comparing an administratively determined calculation of stranded costs (which can change significantly over the course of the capped rate period) to the Company's capped rate recoveries. These capped rate recoveries are based on the revenues resulting from the fair, just and reasonable cost-based rates set by the Commission that the Company receives in return for providing service to its customers.

As noted earlier, the MOU in AP's functional separation plan was designed to address all issues including stranded cost recovery. Also as part of its functional separation plan, AP transferred at book value its generating assets to its unregulated affiliate AE Supply on August 1, 2000. As a result of the asset transfer, AP's generation facilities are now legally and functionally separated from the Company. Consistent with this functional and legal separation, AE Supply's organization is very different from that of AP. AE Supply has different management, separate accounting records, and a different capital structure than AP. Using the proposed Net Present Value (NPV) stranded cost model would incur a significant additional burden on AP relative to other utilities. These difficulties would include additional assumptions necessary to estimate the unregulated affiliate costs as if they were not separated from AP and continuing to operate under regulated rates. For example, an unregulated company may make different decisions related to incurring capital and operating costs than that of a regulated company

Lastly, the proposed NPV model deviates from the lost revenue approach adopted by the legislature. The model attempts to travel down the road of quantification that was, for good reason, abandoned by the legislature, the Virginia SCC Staff, and other significant parties in drafting the Restructuring Act. The Act is a carefully crafted document, reflecting the study, compromise, and negotiation of many parties. It seems inappropriate at this stage in the transition period to deviate from such a central concept upon which the Act was constructed and implemented. In addition, consumers may find it very difficult to understand a new stranded cost process and why the rates or terms used during the transition period have changed from prior announcements. This may result in increased customer frustration with the deregulation process and/or increased phone calls to AP's customer service centers with questions related to price changes or new terms on customer's bills.

2) Comments on the Dominion Virginia Power (DVP) Model

(Definition below from SCC email 4/10/03)

The methodology for calculating "just and reasonable net stranded costs" requires a utility to determine (1) whether there is over- or under-recovery of stranded costs collected through the wires charges from switching customers, and (2) the amounts it has expended from funds available under capped rates to mitigate potential stranded costs less any additional expenditures that negatively impact such costs. Under (1), a company can compare the revenue actually collected from customers via the wires charges based on projected market prices to the revenue that would have resulted had wires charges been based on the actual market prices experienced during that year. If the revenue collected through the wires charges was greater than the revenue that would have resulted had the actual market price been correctly predicted, the wires charges were set too high, resulting in an over-recovery. If the contrary is the case then there is under-recovery.

Advantages

AP does not have a wires charge but feels this method is an equitable, easy to implement and customer friendly way to collect any stranded cost through the transition period. This method protects the customer from over or under paying the wires charge during the transition period.

The DVP model also eliminates the numerous assumptions of the NPV model in favor of using actual data to true up any wires charges collected by the utility. By providing the utility a chance to recover its capped rates through July 2007 it also allows the utility time to mitigate stranded costs where possible and gives the customers and shareholders time to adjust to the deregulated utility environment.

Disadvantages

If stranded costs exceed what is collected through capped rates or the wires charges through 2007 then the utility is not made whole. However, this disadvantage also serves as an incentive to the utility to mitigate its stranded costs as much as possible over the transition period.

Summary

There is no perfect way to quantify stranded costs. The DVP model adds only a true up step to an existing process that results in the customer paying only the just and reasonable rates for generation that were set by this Commission. This method also provides the utility the ability to mitigate stranded costs over the transition period. Due to its fairness, simplicity and administrative ease of application the DVP model should be adopted for recovering stranded costs through the wires charge.

Virginia Independent Power Producers, Inc.
August Wallmeyer, Executive Director
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April 18, 2003

Ms. Susan Larsen
Division of Public Accounting
State Corporation Commission
P.O. Box 1197
Richmond, VA 23218

Via Email and U.S. Mail

Dear Ms. Larsen,

Virginia Independent Power Producers, Inc. (VIPP) offers the following comments on the two conceptual methodologies discussed during the April 7, 2003 meeting of the stranded costs work group.

Very truly yours,

/s/

August Wallmeyer

v0417d

Proposal One: Summarized by Dominion Virginia Power and Generally Agreed To by Several Other Parties, Including VIPP

Proposal 1 – Revised
The methodology for calculating "just and reasonable net stranded costs" requires a utility to determine (1) whether there is over- or under-recovery of stranded costs collected through the wires charges from switching customers, and (2) the amounts it has expended from funds available under capped rates to mitigate potential stranded costs, less any additional expenditures that negatively impact such costs.

Under (1) above, a company can compare the revenue actually collected annually from customers via the wires charges based on projected market prices to the revenue that would have resulted had wires charges been based on the actual market prices experienced during that year. If the revenue collected through the wires charges was greater than the revenue that would have resulted had the actual market price been correctly predicted, the wires charges were set too high, resulting in an over-recovery for that year. If the contrary is the case then there is under-recovery.

In any event, whether the above two measures produce an over- or under-recovery of a utility's total stranded costs cannot be finally determined until after July 1, 2007.

Proposal One compares revenues collected by the wires charge based on estimates of future market prices with revenues that would have been collected by the wires charge if actual future market prices had been known annually at the time wires charges were set. By focusing on the wires charge mechanism, Proposal One properly addresses stranded cost incurrence and stranded cost recoveries during the transition period. As such, Proposal One is consistent with the Virginia Electric Utility Restructuring Act's mandate to *monitor* stranded cost recoveries.

By comparing annual market price projections with actual, known facts, Proposal One avoids the major predictive hazards contained in Proposal Two, the

Commission methodology. Proposal One does not subject interested parties and Virginia consumers to the wildly speculative results that will emerge from the more theoretical, less practical conceptual model that is the Commission methodology.

For these reasons and others, VIPP prefers and supports Proposal One and urges its use.

Proposal Two: The Commission Methodology

Proposal 2 as summarized by Staff:
To calculate just and reasonable net stranded costs compare asset values based on net present value cash flows that arise from remaining in a regulated market (cost plus a fair return) to the net present value cash flows that arise in a competitive market (over the life of the assets). From this amount subtract recoveries via capped rates (to the extent capped rates exceed actual costs including a fair return) and wires charges to determine the over- or under-recovery of just and reasonable net stranded costs.

Preface

The methodology suggested by the Commission is faulty in numerous fundamental ways. While some of the underlying *concepts* contained within the methodology might be workable in theory, *implementation* of those concepts as suggested by the Commission would be extraordinarily difficult in some cases, impossible in other cases. Moreover, because it focuses on heavily on *projections* of stranded costs over an extended time horizon, the Commission's methodology is fundamentally at odds with the notion of *monitoring* as set forth in the Virginia Electric Utility Restructuring Act.

The Commission methodology relies extensively on a myriad of subjective assumptions and long-term future predictions of market prices, customer behavior, interest rates, legislative and regulatory actions, etc.—things that are by their nature impossible to predict with precision. These subjective assumptions and imprecise forecasting results will skew any "results" obtained from the methodology within an extremely wide range. This phenomenon would have two equally disastrous results for the working group.

First, any reliance on longer-term predictions will lead to tremendous division and differences of opinion among the interested parties. As the Commission's presenter of its methodology, Howard M. Spinner, himself said, "Every step [of implementing the Commission methodology] will be fraught with tremendous controversy." This result is exactly opposite the directive issued to the stranded costs work group by the Legislative Transition Task Force (LTTF). The LTTF's resolution established the work group "for the purpose of developing consensus recommendations, consistent with the provisions of the [Virginia Electric Utility Restructuring] Act..."

Second, and perhaps worse, because the results of the Commission's predictive methodology are extremely dependent on the analyst's choice of assumptions, there is a grave danger that the desired results could be determined in advance to suit a party's self-interest in a particular outcome.

For these reasons and others enumerated below, VIPP recommends the work group abandon its consideration of the Commission methodology.

Overview

Use of the Commission methodology would be unfair, unreliable, extremely disruptive and very likely prejudicial to the interests of all interested parties, particularly including Virginia consumers.

A full discussion and analysis of the Commission methodology outlined at the last meeting of the work group on April 7, 2003 would consume more time than is available, considering the time restraints included in the LTTF resolution. In addition, while some conceptual details of the Commission methodology were presented and discussed, many other practical elements were not presented, or were discussed only superficially. Recognizing the truth of the old adage that the devil is in the details, particularly for complicated, fact-intensive ratemaking applications and projections, readers are cautioned that the comments made herein should be considered preliminary in nature and subject to future elaboration.

Inherent Difficulties in Backward-Looking and Forward-Looking Ratemaking

The methodology advocated by the Commission would involve comparing the earnings streams or cash flows that would be realized under traditional regulated rates to the earnings streams that that *might have been* realized during multi-year periods in the past (using untested backward-looking regulatory analyses) and that *might be* realized years into the future in a competitive environment (using untested forward-looking regulatory analyses).

Backward-Looking Difficulties

The Commission methodology would require an analysis comparing recoveries of stranded costs through wires charges and capped rates "to the extent capped rates exceed actual costs including a fair return" during the entire rate cap period from 2001 through July 2007. The analysis would have two separate components: a backward-looking analysis of actual costs and returns, capped rate and wires charge revenues for years 2001and 2002, and a forward-looking analysis of these same components for years 2003, 2004, 2005, 2006 and half of 2007.

In the case of Dominion Virginia Power, determining "actual costs and a fair return" for 2001 and 2002 would be very difficult. Virginia Power's last rate case was settled by means of the stipulation in Case Nos. PUE960296 and PUE960036. The settlement involved interdependent rate and non-rate provisions. It is well-known that stipulations are not allowed to have any precedential effect in administrative proceedings, because they involve trade-offs and are, by their very nature, unreliable as a guide to any one particular element of the stipulation. Consequently, the rate case elements of a stipulation can not be viewed or treated in isolation. Specifically, in Dominion Virginia Power's case, rate case elements of the stipulation can not be used validly to determine the Dominion's "actual cost and fair return" for the last two years of the five-year rate period, 2001 and 2002. Accordingly, to satisfy the beginning demands of the Commission methodology, the working group would be required to conduct retrospective rate case analyses to establish a revenue requirement for the prior years, and to determine a "fair" rate of return on the utility's capital for 2001 and 2002.

The complexity and controversy of this portion of the Commission's methodology would be extraordinary. As in traditional rate case applications, all major parties of interest would employ the services of numerous industry expert witnesses. Contested proceedings of this type routinely span months or years of litigation and consume millions of dollars in expenses for analysis, preparation, testimony and cross examination.

Moreover, another major difficulty presents itself when considering such backward-looking rate analyses. Traditional rate cases examine an actual test year during which a utility company has recorded its business transactions in generally-accepted ways consistent with ongoing regulatory oversight and scrutiny. Since the generation component of traditional utility service has been deregulated in Virginia since 1999, it is highly unlikely that a utility's record keeping under a deregulated environment would be adequate now for an after-the-fact rate reconsideration based on completely different criteria.

Forward-Looking Difficulties

The Commission's methodology would require *projecting* an incumbent utility's actual costs and returns during the remainder of the legislatively-determined transition period, for years 2003, 2004, 2005, 2006 and half of 2007. This exercise would require setting rates (*i.e.*, "actual costs" and a fair return) in 2003 for each of the four years in the remainder period on the basis of *future test years*. That challenge is daunting and unprecedented.

Such forward-looking ratemaking would require the Commission to determine in advance, by guesswork, speculation or other means, all of a utility's major expense categories. For example, predictions would have to be made for future wage rates, capital expenditures for new generation facilities, levels of customer demand, weather patterns and trends, maintenance and repair expenditures and all other non-fuel related components of ongoing operations. In addition, future forecasts would have to be made concerning local, state and federal taxation rates, interest rates on all components of a utility's capital structure, and necessary future equity return levels. Again here, the level of difficulty can not be overstated. If such predictive ability existed, it surely would be in use now. Unsurprisingly, such predictive ability does not exist, and considering a methodology based on its use is illogical.

Commission Methodology Would Require Functionalization/Unbundling

Because consideration of a utility's stranded costs involves only generation-related assets, it would be necessary to separate out of bundled capped rates those expenditures and the corresponding revenue requirement applicable only to generation. This required unbundling would be necessary for each of the years 2001-2007 in question. Such separation would be very lengthy and complex.

Retroactive Ratemaking

Incumbent utilities in Virginia have been operating since 2001 according to the foundations established in the Virginia Electric Utility Restructuring Act. As the Act does not contemplate the possibility of future actions overturning its basic terms, incumbent utilities have planned and made expenditures with the expectation that capped rate revenues were secure through the legislatively-determined time period and not subject to retroactive analysis or adjustment.

To now suggest changing the statutory and regulatory framework to provide for retroactive rate review and adjustment would be to unfairly call into question every decision made by a utility and subject it to new, different and unexpected review standards. For example, if a utility were operating in a traditional cost of service environment instead of a capped rate environment, cost savings measures such as employee layoffs might have occurred at a different pace, or not at all. A multitude of other business decisions (regional consolidation of business offices, repair crews, maintenance scheduling, etc.) might also have been made differently. Retroactively re-imposing a cost of service regime with different economic signals and incentives would unfairly penalize utilities, skew the actual and reported results of their past operations, unfairly deprive stakeholders of their reasonable expectations of regulatory stability and create a host of other problems. In long standing widely-recognized regulatory practice, the filed rate doctrine and the rule against retroactive ratemaking exist to prevent the basic unfairness to the regulated community and its customers that is inherent in the Commission's proposed methodology.

Commission Methodology Would Require Projecting the Projections

The first element of the Commission methodology would require a determination of capped rate and wires charge revenues. To make this determination for the years 2003-2007, the working group would have to project the number of customers who would switch electricity suppliers from an incumbent utility to some alternative supplier during the remainder of the capped rate period. This would pose severe methodological problems.

As more customers switch to unregulated alternative suppliers, demand within the deregulated component of the market would be expected to increase. Increased demand would lead to increased prices, which increases would need to be factored into the working group's projection of future market prices. So, it would be necessary for the working group first to project the number of switching customers, then to determine the effect on pricing in a competitive market, then to project what those future prices would be, then to compare those projected future market prices to wires charge revenues collected during the period, which wires charge revenues would be expected to decline in proportion to the number of customers switching suppliers. The circular logic inherent in this aspect of the Commission's methodology can not possibly be expected to yield dependable results.

Hazardous Future Projections of Asset Values and Revenue Streams

Another required element of the Commission's methodology regarding stranded costs would be to calculate "asset values based on net present value cash flows that arise from remaining in a regulated market (cost plus a fair return)." This determination would require an estimation of the embedded cost-based rates for generation supply over an extended period of time associated with the economic lifetime (assumed to be thirty years, for purposes of this discussion) of Dominion Virginia Power's current generation assets. This would require two distinct projections, each of which would be controversial, speculative and complex.

The first element would require projections of *embedded cost-based pricing* for generation assets during each year of the thirty-year period. Accordingly, rate of return and other cost elements such as capitalized generation costs for pollution control equipment, would have to be estimated long into the future. These estimates would be exceedingly difficult, particularly since their nature and magnitude would depend on future environmental laws and regulations that have not yet been determined, examined, discussed or enacted. In addition, Proposal Two would require projections of variable costs to determine the future earnings streams and cash flows. Accordingly, to determine *future cash flows and earnings*, the working group would have to estimate, for each generation unit in a utility's fleet, fuel costs and other variable operating and maintenance expenses thirty years into the future. Such estimates can not possibly yield dependable results.

The next aspect of the Commission's methodology, determining the net present value cash flows that would arise in a competitive market, is likewise exceedingly difficult and speculative. Several individual components would be involved in making this determination—each presenting unique challenges and difficulties.

First, a computer model would have to be employed to project market prices for capacity and energy over the life of the utility's assets. Such projections are inherently speculative and subject to wide error margins. The capacity price prediction program would have to model regional capacity supply and demand conditions. In addition, it would have to incorporate a method to determine when and whether new capacity additions would be built in response to regional demands. Various complex constraints would have to be built into the model to ensure that the modeled capacity that would be predicted to be built would be included only if the associated energy prices were sufficient to provide a contribution to capital.

Next, the computer model would have to approximate regional generation commitment and dispatch, as well as customer demand on some periodic basis. The model would need to determine—by approximation, estimation or some other method—market clearing prices for each year of the thirty year time horizon.[1]

Once market clearing prices were estimated, it would be necessary to determine whether each generating unit would actually run during a particular time period. This would require modeling each generating unit's marginal costs and comparing them, unit-by-unit, to the projected market clearing prices during the entire time period.

The Virginia Power Transition Cost Report represented an attempt to determine stranded costs for a far shorter period of time than would be required by the Commission methodology. In addition, the method used by Virginia Power was not nearly as complex and detailed as the methodology suggested by the Commission. Even

[1] For a more complete understanding of the difficult nature of the required computer modeling, refer to the Virginia Power Transition Cost Report, Part B, submitted in Case No. PUE960296.

employing this "simpler" approach, the Virginia Power Transition Cost Report noted that the simulation model was extraordinarily sensitive to the chosen assumptions.

In sum, the challenges inherent in the post-2007 projections that are an integral part of Proposal Two are vast and unfathomable. The difficulty of these challenges *is huge in comparison* to those discussed above in the context of the futuristic ratemaking exercise that would be required under the Commission methodology during the pre-2007 period. While the pre-2007 analyses are at least tenuously rooted in present-day facts, the post-2007 projections would be free-floating guesswork, impossible to benchmark against any independent standard. As an illustration, one may simply ask, who could or would have predicted the mid-west price spikes of several years ago, or the California crisis of 2000-2001, with prices reaching unprecedented levels far above $100/MWh? The answer is that the thirty-year projections that are such an integral part of Proposal Two would not be worth the paper they are printed on. Indeed, the sensitivities inherent in the use of computer models were demonstrated in the case by contrasting Virginia Power's results with those offered by another party. The two estimates of stranded costs—for shorter projection periods than envisioned by the Commission methodology—differed by more than $5 billion!

Conclusion

As discussed above, Proposal One is both practical and consistent with the Virginia Electric Utility Restructuring Act. Proposal Two, on the other hand, would be based on impossible predictive guesswork. If the expertise to *predict with any degree of precision* the future performance of a utility's business actually existed, surely it would be put to other use. Such predictive power could, for example, completely dominate a utility's publicly traded securities. Or control the entire stock market. Or rule futures trading markets. Or completely control competing businesses or industries. Such a concept is folly and it should be recognized as such.

The working group should reject the Commission methodology and accept Proposal One.

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STRANDED COSTS WORK GROUP
SCC Case No. PUE-2003-00062

DIVISION OF CONSUMER COUNSEL
OFFICE OF THE ATTORNEY GENERAL
COMMENTS ON PROPOSED CONCEPTUAL MODELS
FOR QUANTIFIYING JUST AND REASONABLE
<u>NET STRANDED COSTS</u>

As requested at the stranded costs work group meeting on April 7, 2003, the Division of Consumer Counsel, Office of the Attorney General ("Consumer Counsel") submits these comments in response to the two proposals made to the work group on the issue of a methodology for calculating just and reasonable net stranded costs.

I. BACKGROUND

The Commission convened the work group, by its Order Establishing Proceeding of March 3, 2003, to develop consensus recommendations to the General Assembly's Legislative Transition Task Force ("LTTF") addressing the definition of stranded costs, the proper method of quantifying potential stranded costs, and the status of recovery of stranded costs to date by Virginia's electric utilities. Specifically, the LTTF's resolution of January 27, 2003 requests the Commission to:

> 1. Convene a work group . . . for the purpose of developing consensus recommendations, consistent with the provisions of the Act, regarding the issues listed in paragraphs 2 and 3. . . .
>
> 2. By July 1, 2003, present to the [LTTF] the work group's consensus recommendations regarding:
>
>   (a) Definitions of "stranded costs" and "just and reasonable net stranded costs."
>   (b) A methodology to be applied in calculating each incumbent electric utility's just and reasonable net stranded costs, amounts recovered, or to be

recovered, to offset such costs, and whether such recovery has resulted in or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs; and

3. By November 1, 2003, present to the [LTTF] the work group's consensus recommendations, developed using the methodology developed pursuant to paragraph 2(b), regarding:

   (a) The amount of each incumbent electric utility's just and reasonable net stranded costs.
   (b) The amount that each incumbent electric utility has received, and is expected to receive over the balance of the capped rate period, to offset just and reasonable net stranded costs from capped rates and from wires charges.

Consumer Counsel understands that the issue to be addressed in these comments pertains only to the first clause of item 2(b): "A methodology to be applied in calculating each incumbent electric utility's just and reasonable net stranded costs."

It is implicit from this language that the LTTF recognizes that no such methodology currently exists in the Restructuring Act. The LTTF staff document of November 19, 2002, titled "Quantifying Incumbent Electric Utilities' Stranded Costs"[1] provides some helpful legislative history on the issue of stranded cost monitoring and quantification. It notes that Senate Bill 1269 as introduced was silent on the issue of who would determine stranded costs, and that § 56-595 was amended in committee to direct the LTTF to monitor the issue. (Section 56-595 C now provides that the LTTF shall monitor whether the recovery of stranded costs, as provided in § 56-584, has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs . . . .")

[1] http://dls.state.va.us/groups/elecutil/11_19_02/quantify.pdf ("November 19 Report").

The November 19 Report states that the LTTF, at its December 21, 2001, meeting, agreed to inform the Commission that it would want certain information for use in monitoring utilities' recovery of stranded costs. It then cites to the Commission's 2002 report on the status of competition wherein the SCC noted that the Restructuring Act neither defines stranded costs nor provides any formula or statutory framework for their calculation. The November 19 Report quotes the SCC's observation that "since measuring the 'underrecovery' or 'overrecovery' of stranded costs under § 56-595 C requires their quantification, it will be necessary to adopt a formula or method for their calculation."

II. GENERAL COMMENTS ON METHODOLOGIES

Consumer Counsel can support the use of a "lost revenues" approach of quantifying stranded costs. While a lost revenues approach is not perfect, and typically requires many assumptions, it is generally the most appropriate method for calculating stranded costs in Virginia since the Restructuring Act does not mandate or provide for market-based approaches – such as plant divestiture or capacity auctions – to be used to determine stranded costs. A lost revenues method is consistent with Consumer Counsel's definition of "stranded cost" proposed in its March 21, 2003 Responses to Questions Set Out in Order of March 3, 2003."[2] Compared to a market-based approach, both proposed methodologies could be considered a lost revenues model.

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[2] This definition proposed by Consumer Counsel is: Stranded costs are a utility's lost revenues arising from prudently incurred, verifiable and non-mitigable electric generation-related costs that become unrecoverable due to restructuring and retail competition.

III. COMMENTS ON SPECIFIC PROPOSALS

A. Proposal 1 (Dominion Virginia Power)

> The methodology for calculating "just and reasonable net stranded costs" requires a utility to determine (1) whether there is over- or under-recovery of stranded costs collected through the wires charges from switching customers, and (2) the amounts it has expended from funds available under capped rates to mitigate potential stranded costs, less any additional expenditures that negatively impact such costs. Under (1), a company can compare the revenue actually collected annually from customers via the wires charges based on projected market prices to the revenue that would have resulted had wires charges been based on the actual market prices experienced during that year. If the revenue collected through the wires charges was greater than the revenue that would have resulted had the actual market price been correctly predicted, the wires charges were set too high, resulting in an over-recovery for that year. If the contrary is the case then there is under-recovery. In any event, whether the above two measures produce an over- or under-recovery of a utility's total stranded costs cannot be finally determined until after July 1, 2007.

Proposal 1, which has been advanced by Dominion Virginia Power, appears to be based on the Restructuring Act's statutory framework for determining wires charges, which are designed as a means to recover stranded costs. The company is apparently seeking to extend the Act's wires charge recovery methodology to a method for calculating actual stranded costs. The company's proposal reflects the fact that stranded costs were not defined and quantified at the time of the Act's passage.

The Commission has noted that under § 56-583 of the Restructuring Act, "wires charges serve as a 'proxy,' on a utility by utility basis, of stranded costs. Therefore, no actual determination of stranded costs is necessary as a precondition of receipt of wires charges."[3] Thus, while the Act allows utilities to recover any stranded costs via a wires

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[3] Application of Northern Virginia Elec. Coop., for review of tariffs and terms and conditions of service, Case No. PUE-2002-00086, Final Order at 2, n. 3 (June 18, 2002).

charge (and through capped rates), amounts recovered by a wires charge are not synonymous with a utility's actual stranded costs, but are only a proxy for such costs.

Because wires charges serve only as a proxy for stranded costs, this first proposal does not consider a utility's current generation costs in calculating stranded costs, but rather uses its capped rates and wires charges (unbundled generation cost) to represent its current cost of service. As a result, any stranded cost mitigation to date and going forward due to reduction in operating costs, depreciation, or other factors (or any increased generation costs) are not captured under Proposal 1.

As noted, the overarching aspect of the first proposal is its carry forward of the current proxy methodology used for determining wires charges. To this end, Proposal 1 could be relatively uncomplicated and usable in a relatively short timeframe. On the other hand, the proposal assumes that the wires charge reflects a utility's actual unbundled generation costs for that year. Again, to the extent the utility's unbundled generation costs have decreased due to mitigation, depreciation or other such factors from the level used to set the wires charges (or if costs have increased for any reason), the approach of Proposal 1 will not capture such changes.

Consumer Counsel is not clear how the mitigation component of Proposal 1 is to operate. The proposal defines mitigation to be considered in the calculation of stranded costs as "the amounts [a utility] has expended from funds available under capped rates to mitigate potential stranded costs, less any additional expenditures that negatively impact such costs." This definition does not provide a standard that should be applied in determining an appropriate level of mitigation. Further, it is unclear how such figures, once determined, would be used in the calculation.

B. Proposal 2 (SCC Staff)

> To calculate just and reasonable net stranded costs compare asset values based on net present value cash flows that arise from remaining in a regulated market (cost plus a fair return) to the net present value cash flows that arise in a competitive market (over the life of the assets). From this amount subtract recoveries via capped rates (to the extent capped rates exceed actual costs including a fair return) and wires charges to determine the over- or under-recovery of just and reasonable net stranded costs.

Proposal 2, presented by Howard Spinner for the SCC's staff, is also a lost revenues approach. While many details regarding the calculation mechanics and assumptions will have to be addressed in order to apply this proposal, it appears the conceptual framework is not inappropriate, and is consistent with lost revenues approaches that have been used in other jurisdictions to quantify stranded costs, such as the "ECOM" (excess costs over market) model used in Texas. This approach, however, would, be difficult to undertake in a work group setting as it most likely would require involved proceedings with expert testimony subject to cross examination.

If the Proposal 2 approach is used, Consumer Counsel believes several changes to the description above should be made for clarification of what we understand the intent to be. We suggest that the terms "cash flows" and "recoveries" should be clarified by using the term "regulated and market-based revenues." The proposal should be clarified to include regulatory assets and liabilities, and to provide that the Virginia retail jurisdictional share of stranded costs will be quantified since the jurisdictional share of stranded costs is the most relevant information when evaluating Virginia's exposure to and policies for dealing with any stranded costs.

In order to arrive at reasonably accurate calculations of stranded costs, any application of the lost revenues method must be carefully designed to capture only those lost regulated revenues arising from retail competition that would reasonably have been expected to occur (net of mitigation) over the remaining life of the assets. In order to accomplish this, there must be accurate information on the current investment balances, operating costs and performance of the utility's generating assets.

There must also be reasonable forecasts of items which impact stranded cost results, such as customer switching levels during the transition (capped rate) period, customer sales, future market prices, and future costs, operating levels and retirement dates for the utility's generating assets. Typically, uncertainty in forecast assumptions should be addressed by considering multiple scenarios, with the final stranded cost estimates reflecting the results of the most probable runs. This lost revenues method is the same basic process that was used by electric utility resource planners in justifying the utility's initial investments in generating assets. Finally, we note that great care must be taken in the selection of the appropriate discount rates and in modeling various components of the regulated revenue stream so that stranded costs are not "created" through the modeling process.

IV. CONCLUSION

As noted in our March 21, 2003, responses to the Commission's initial questions, Consumer Counsel recognizes the significant challenges inherent in the task of attempting to develop consensus on the issues of potential stranded cost quantification and recovery through the work group process. We are particularly mindful of the Restructuring Act's statutory scheme which on the one hand did not require an up-front quantification of actual stranded costs as a prerequisite for their recovery through wires charges and capped rates, but which also requires the LTTF to monitor, with the assistance of stakeholders, whether the recovery of stranded costs has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs.

Consumer Counsel appreciates that, in order to reach consensus, any application of the work group's findings should attempt to preserve the protections afforded to all the various stakeholder interests under the Restructuring Act. It is Consumer Counsel's position that any approach developed by the work group must, at a minimum, retain the consumer protections in place under the Restructuring Act.

DIVISION OF CONSUMER COUNSEL
OFFICE OF THE ATTORNEY GENERAL

April 18, 2003

Virginia Citizens Consumer Council
Comments on Conceptual Models for Stranded Costs Over/Under Recoveries
April 16, 2003

First, the definition of stranded costs is broad and could contain many different kinds of costs. Essentially, VCCC believes that the key parts of stranded costs are the costs of tangible assets that were originally planned to be repaid over a longer period than 2007 and which utilities might have problems repaying if they have fewer customers in the restructured market. For the purpose of these calculations, it is important to focus on the actual costs and what has been/is recouped. It is inappropriate to compare income that could have been received from the market with actual income received during the transition.

The purpose of this exercise is to get ready for the competitive market, putting utilities on a level playing field. To assure that a truly competitive market will develop, it is important to determine incumbent utilities' net stranded costs and net actual compensation during this transition period. The goal is to assure that incumbent utilities are not placed in a position where they cannot meet their obligations because the market changed. At the same time, it is critical to assure that potential competitors of incumbent utilities are not set up at a disadvantage because incumbent utilities recovered more than their actual losses.

Proposal 1

Advantages:

The second version of this proposal improved it marginally by incorporating excess revenue from capped rates.

Disadvantages:

This strategy still allows utilities to avoid identifying and quantifying the actual stranded costs. This is not acceptable. We need to determine what costs utilities cannot reasonably recover under the future competitive market, their quantity, and then what costs have been recovered through the wires charges and capped rates. Market rates that could have been received during the time are not a part of this equation. Utilities agreed to a certain level of income certainty during the transition period instead of calculating the stranded costs earlier in this process. It is not fair to incorporate market rates because they did/do not apply during the transition time. Since Virginia's rates have long been below market rates, the proposed strategy sets the stage for guaranteed utility gains. This is not fair to either consumers or competitors of incumbent utilities.

Proposal 2

Advantages:

This strategy actually is a means to compare income from a regulated market with a competitive market and takes into consideration the full lifetime value of assets. After calculating the stranded costs it requires subtracting excess revenues from capped rates (subtracting actual costs and a fair return from capped rates) and wires charges. This is fair and reasonable.

Disadvantages:

It is based upon future market prices, on which it is likely the various parties will continue to disagree.

Submitted by Irene E. Leech, President, (540 231 4191; ileech@vt.edu)

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April 16, 2003

DELIVERED ELECTRONICALLY

Ronald A. Gibson, Director
Division of Public Utility Accounting
State Corporation Commission
1300 East Main Street
Richmond, VA 23219

Re: ***Commonwealth of Virginia, ex.rel. State Corporation Commission***
In the matter of developing consensus recommendations on stranded costs
Case No. PUE-2003-00062

Dear Ron:

The Commission Staff has requested comment on two proposed methodologies for calculating "just and reasonable net stranded costs" and their recovery. One proposal has been submitted on behalf of the SCC Staff; the other has been submitted by Virginia Electric and Power Company ("Virginia Power"). The following comments are submitted on behalf of the Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates (collectively, "Committees").

Introduction

Section 56-595.C (iii) of Virginia's Electric Utility Restructuring Act ("Act") provides that the members of the Legislative Transition Task Force ("LTTF") shall:

> ... monitor ... whether the recovery of stranded costs, as provided in § 56-584, has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs.

Thus, the Act requires the LTTF to monitor the over-recovery or under-recovery of just and reasonable net stranded costs. To monitor an "over-recovery" or "under-recovery," the LTTF must determine and compare two things: first, the amount that has been, or will be, available for recovery of just and reasonable stranded costs, and, second, the amount of just and reasonable stranded costs.

The Act, in Section 56-584, provides that two sources of revenue are available for recovery of just and reasonable net stranded costs -- capped rates and wires charges. Thus, the answer to the first side of the inquiry is straightforward: the amount that has been, or will be, available for recovery of such costs are the revenues collected from wires charges and the revenues collected from capped rates in excess of the revenues needed by the utility to recover its costs of providing service (*i.e.*, the utility's revenues in excess of its revenue requirement).

The Commission Staff's proposal recognizes both sides of the inquiry required of the LTTF – *i.e.*, (i) just and reasonable net stranded costs and (ii) the amount available for recovery of such costs through wires charges and capped rates. Virginia Power's proposal, in contrast, while stating that it represents a "methodology for calculating 'just and reasonable net stranded costs,'" does not calculate such costs. Nor does Virginia Power's proposal calculate the amount available for their recovery, despite making reference to "over-recovery" and "under-recovery." Thus, Virginia Power's proposal calculates *neither* side of the inquiry required of the LTTF by Section 56-595 C (iii). Virginia Power's proposal compares annual projections of revenue using market prices used to calculate wires charges with annual revenue that would have been collected if actually experienced market prices had been used. Virginia Power further makes mention of expenses for "mitigating" stranded costs less certain other expenditures that reduce such costs. It does not, however, provide a method to calculate just and reasonable net stranded costs or the means for their recovery. We discuss both the Staff's and Virginia Power's proposals at greater length below.

Staff's Proposal

The Commission Staff's Proposal states:

> To calculate just and reasonable net stranded costs compare asset values based on net present value cash flows that arise from remaining in a regulated market (cost plus a fair return) to the net present value cash flows that arise in a competitive market (over the life of the assets). From this amount subtract recoveries via capped rates (to the extent capped rates exceed actual costs including a fair return) and wires charges to determine the over- or under-recovery of just and reasonable net stranded costs.

Subject to the two clarifications below, the Committees agree that the Staff's proposal represents an acceptable, administrative methodology for the calculation of just and reasonable net stranded costs and their recovery under the Restructuring Act. By reference to the "regulated market (cost plus a fair return)," the methodology incorporates traditional ratemaking concepts in a regulated environment, including consideration of a utility's regulated cost of service used in setting "just and reasonable" rates, and including concepts of "prudence," mitigation, verification, and the "netting" of stranded costs and margins. The methodology properly requires consideration of the useful life of assets. The Committees already have described limitations on administrative methods and the critical importance of the underlying assumptions and models employed.

We would suggest two clarifications. First, Staff's methodology might be interpreted to calculate stranded costs as the difference between *two* net present value ("NPV") cash flows. The calculation should be characterized as the NPV of the *difference* between the market value and the regulated value of the utility's generation assets over their remaining useful lives. In other words, the calculation should be characterized as having only *one* NPV cash flow (*i.e.*, the difference), not the difference between two NPV cash flows. Thus, for example, in calculating the NPV, only one discount rate should apply to one cash flow (the difference), not two different discount rates to two different cash flows.

Second, Staff's methodology might be interpreted to preclude calculation of the "likely" over-recovery or under-recovery of just and reasonable net stranded cost, as provided in Section 56-595.C (iii), because of Staff's reference to "actual costs." Thus, a better way to state it might be as follows:

> To calculate just and reasonable net stranded costs compare asset values based on the net present value of the difference between the cash flow that arises from remaining in a regulated market (cost plus a fair return) and the cash flow that arises in a competitive market (over the life of the assets). From this amount subtract recoveries via capped rates (to the extent capped rates exceed actual and likely costs including a fair return) and wires charges to determine the over- or under-recovery of just and reasonable net stranded costs.

The stated means of recovery of such costs – capped rates and wires charges – follow the design of the Act, as discussed above.

Virginia Power's Proposal

As you have indicated, Virginia Power summarized its proposal in its comments of March 21, 2003, at page 5, and revised it on April 10, 2003. Its proposal, as revised, states:

> The methodology for calculating "just and reasonable net stranded costs" requires a utility to determine (1) whether there is over- or under-recovery of stranded costs collected through the wires charges from switching customers, and (2) the amounts it has expended from funds available under capped rates to mitigate potential stranded costs, less any additional expenditures that negatively impact such costs. Under (1), a company can compare the revenue actually collected annually from customers via the wires charges based on projected market prices to the revenue that would have resulted had wires charges been based on the actual market prices experienced during that year. If the revenue collected through the wires charges was greater than the revenue that would have resulted had the actual market price been correctly predicted, the wires charges were set too high, resulting in an over-recovery for that year. If the contrary is the case then there is under-recovery. In any event, whether the above two measures produce an over- or under-recovery of a utility's total stranded costs cannot be finally determined until after July 1, 2007.

Virginia Power's proposed "methodology" raises a number of concerns. In identifying those concerns in the comments below, we discuss components of the proposal separately.

<u>Virginia Power's Proposal:</u>

> *The methodology for calculating "just and reasonable net stranded costs" requires a utility to determine <u>(1) whether there is over- or under-recovery of stranded costs collected through the wires charges from switching customers, and (2) the amounts it has expended from funds available under capped rates to mitigate potential stranded costs, less any additional expenditures that negatively impact such costs</u>.*

<u>Comment</u>:

Virginia Power's proposal requires "a utility" to make two "determin[ations]"): (1) <u>whether</u> there is over-recovery or under-recovery of "stranded costs" collected through wires charges, and (2) <u>the amounts</u> expended from funds available under capped rates to mitigate stranded costs "less any additional expenditures that negatively impact such costs."[1]

[1] It is not clear why "a utility" should or must make a determination in order to calculate just and reasonable net stranded costs. The methodology for calculating such costs should not depend upon the type of entity making the calculation. Of course, in the current context, the LTTF is charged with monitoring the over-recovery or under-recovery of just and reasonable net stranded costs.

The first of these two determinations, however – whether there is over-recovery or under-recovery of stranded costs collected through wires charges -- is not a "methodology" for calculating stranded costs or anything else. It is merely a statement of an issue – *i.e.*, a question ("whether") that calls for an answer of "yes" or "no."

The second of the two determinations – "amounts expended … to mitigate potential stranded costs, <u>less</u> any additional expenditures that negatively affect such costs" (Emphasis added) – is confusing and seems, at best, pointless. Assuming that one wishes to calculate amounts spent by a utility from funds available under capped rates to "mitigate" stranded costs, it is far from clear why one would subtract from those amounts "additional expenditures" that would further reduce (*i.e.*, "negatively affect") "such [stranded] costs." That is, assuming that some purpose might be served by calculating amounts spent to mitigate potential stranded costs, it is not clear why one would wish to <u>reduce</u> those amounts further by "additional expenditures" spent to "negatively affect," or reduce, such stranded costs. Thus, while the second of the two determinations appears, unlike the first, to contemplate a calculation, the purpose of the calculation, and its relationship to any known or accepted methodology for calculating just and reasonable net stranded costs, is unclear.

Finally, once a utility makes the above two determinations, in "(1)" and "(2)," Virginia Power's proposal does not tell us what we should do to calculate just and reasonable net stranded costs. In other words, once we have answered the first of the two determinations "yes" or "no," and once we have made the calculation intended by the second, what further "calculation," if any, is needed to calculate "just and reasonable net stranded costs"? The proposal does not say.

<u>Virginia Power's Proposal</u>:

> *Under (1), a company can compare the revenue actually collected annually from customers via the wires charges based on projected market prices to the revenue that would have resulted had wires charges been based on the actual market prices experienced during that year. If the revenue collected through the wires charges was greater than the revenue that would have resulted had the actual market price been correctly predicted, the wires charges were set too high, resulting in an over-recovery for that year. If the contrary is the case then there is under-recovery.*

<u>Comment</u>:

The quoted section amplifies the first of the two "utility" determinations discussed above. It contemplates, in essence, an annual calculation of the difference between revenue from wires charges and revenue that would have been collected "had wires charges been based on the actual market prices experienced during that year." If revenue from wires charges is greater, there is an over-recovery of stranded costs; if actually experienced revenues from wires charges are greater, then there is an under-recovery. In prior submissions in this matter, Virginia Power and several other interested parties have emphasized this approach as a methodology for calculating stranded costs.

The proposed calculation of the "over-recovery" or "under-recovery" of stranded costs suffers from several defects. First, it merely calculates the annual revenue effect of the difference between actual and projected market prices used for calculating wires charges. Such a calculation, however, does not represent a methodology for calculating stranded costs. In fact, it has almost nothing to do with stranded costs – *i.e.*, with costs that are not recovered or recoverable as a result of retail customer choice. We are not aware of *any* jurisdiction that even suggests that such a methodology would produce a calculation of a utility's stranded costs.

Virginia Power's proposed calculation, moreover, is not only unrelated to the calculation of "stranded costs," it is also unrelated to the calculation of costs that might be considered "just and reasonable" in setting utility rates; and it is unrelated to any concept of "netting" stranded margins, or benefits, and stranded costs. In short, calculating the annual revenue effect of the difference between actual and projected market prices used for calculating wires charges does not yield a calculation of stranded costs, just and reasonable stranded costs, or just and reasonable net stranded costs.

We note that Virginia Power's proposal in this matter bears no relation to its prior, proposed methodology for calculating stranded costs. In Virginia Power's prior rate case, PUE960296, Virginia Power's proposed an "administrative" methodology for the calculation stranded costs that, while deficient in key respects, bears no relationship to its present proposed methodology. (*See*, the Committees' comments, dated March 21, 2003, in this matter, which include, as an attachment, testimony of the Virginia Committee in response to Virginia Power's stranded cost analysis in that case.)

Virginia Power's and others' apparent rationale for their proposal is that it is somehow mandated or intended by the Restructuring Act. The Act, however, nowhere provides for such a calculation, nor does it imply that such a calculation is intended. The Act does not provide a methodology for calculating just and reasonable net stranded costs. Section 56-584 of the Act provides:

> Just and reasonable net stranded costs, to the extent that they exceed zero value in total for the incumbent electric utility, shall be recoverable by each incumbent electric utility provided each incumbent electric utility shall only recover its just and reasonable net stranded costs through

> either capped rates as provided in § 56-582 or wires charges as provided in § 56-583.

Thus, Section 56-584 provides two means *for the recovery* of just and reasonable net stranded costs -- (1) capped rates as provided in § 56-582 and (2) wires charges as provided in § 56-583. Section 56-584 does not include a definition of just and reasonable stranded costs or a methodology for their calculation.

Section 56-595.C (iii) supports this view. That provision states that the members of the Legislative Transition Task Force shall:

> ... after the commencement of customer choice, monitor, with the assistance of the Commission, the Office of the Attorney General, incumbent electric utilities, suppliers, and retail customers, *whether the recovery of stranded costs, as provided in § 56-584*, has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs.

Thus, § 56-595.C (iii) characterizes § 56-584 as providing for the "recovery" of stranded costs. It does not suggest that § 56-584 somehow defines or quantifies just and reasonable net stranded costs. The suggestion that the Act provides for, let alone mandates, Virginia Power's proposed methodology for calculating just and reasonable net stranded costs finds no support in the Act.

The LTTF's resolution establishing the Commission's work group further erodes any claim that the Act supports Virginia Power's suggested methodology. The resolution asks the work group to seek consensus on a definition and a methodology for calculating just and reasonable net stranded costs. If such a definition and methodology already were specified by the Act, the LTTF's resolution would be superfluous.

Virginia Power's Proposal:

> *In any event, whether the above two measures produce an over- or under-recovery of a utility's total stranded costs cannot be finally determined until after July 1, 2007.*

Comment:

It is not clear whether the "two measures" referenced in the quoted passage refer to the two determinations (*i.e.*, number "(1)" and "(2)"discussed above), or whether the "two measures" refer to the actual vs. projected market prices used in calculating wires charges. In any event, Section 56-590.C (iii) of the Restructuring Act requires the LTTF to monitor, *after the commencement of customer choice*, whether the recovery of stranded costs *has resulted or is likely to result* in the overrecovery or underrecovery of just and reasonable net stranded costs. Thus, the Act authorizes the LTTF to commence monitoring the actual ("has resulted") or likely ("likely to result") over-recovery or under-recovery of just and reasonable net stranded costs upon commencement of customer choice. The Act does not require the LTTF to wait until July 1, 2007, when some "final" determination of the recovery of just and reasonable net stranded costs can be made, and, indeed, the LTTF has not elected to do so, as evidenced by its adoption of its resolution.

It is important, moreover, that such monitoring commence. We are informed that, in a recent earnings report for Dominion North Carolina Power filed with the North Carolina Utilities Commission, Virginia Power states that it earned a 17.90% overall return on equity ("ROE") in 2002 and that it earned a 19.25% ROE from Other Retail Jurisdictions, which is primarily Virginia. We also are informed that, according to Virginia Power, its high earnings are due to hotter than normal weather and that increased expenses in 2003 associated with $900 million of capital expenditures and pension costs, coupled with a return to more normal weather, causes it not to expect its 2003 ROE to approach the level reported for 2002. Nonetheless, with earnings of this magnitude, it is clear that Virginia Power is recovering through capped rates significant dollars toward stranded costs, assuming that it has any positive stranded costs to begin with.

We appreciate the opportunity to comment and hope the above is helpful. Please contact me if you have any questions concerning this submittal.

Very truly yours,

Edward L. Petrini

cc: State Corporation Commission
Division of Economics and Finance
(econfin@scc.state.va.us)

#633462

From: Kaufmann, Michael [mailto:michaelkaufmann@dwt.com]
Sent: Wednesday, April 16, 2003 12:59 PM
To: Susan Larsen
Subject: Methodology

TXI-Chaparral (Virginia) Inc. generally supports the Staff's conceptual model with the following suggested modifications:

> To calculate just and reasonable net stranded costs compare asset values based on net present value cash flows that arise from remaining in a regulated market (***just and reasonable, prudently incurred non-mitagable generation*** costs plus a fair return) to the net present value cash flows that arise in a competitive market (over the life of the assets). From this amount subtract recoveries via capped rates (to the extent capped rates exceed actual ***just and reasonable, prudently incurred non-mitagable generation*** costs including a fair return) and wires charges to determine the over- or under-recovery of just and reasonable net stranded costs.

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April 16, 2003

The Stranded Costs Working Group
Virginia Corporation Commission
Tyler Building, 1300 E. Main St.
Richmond, Virginia 23219

Washington Gas Energy Services (WGES) appreciates the opportunity to respond to the two stranded costs methods as presented to the Stranded Costs Working Group. Although this task was not fully addressed during pre-restructuring it is not too late to tackle it now. We thank the Commission for facilitating this process.

Model 1

The proposal as proffered by Dominion Virginia Power (revised version) is summarized as follows:

> The methodology for calculating "just and reasonable net stranded costs" requires a utility to determine (1) whether there is over- or under-recovery of stranded costs collected through the wires charges from switching customers, and (2) the amounts it has expended from funds available under capped rates to mitigate potential stranded costs, less any additional expenditures that negatively impact such costs.
>
> Under (1), a company can compare the revenue actually collected annually from customers via the wires charges based on projected market prices to the revenue that would have resulted had wires charges been based on the actual market prices experienced during that year. If the revenue collected through the wires charges was greater than the revenue that would have resulted had the actual market price been correctly predicted, the wires charges were set too high, resulting in an over-recovery for that year. If the contrary is the case then there is under-recovery.
>
> In any event, whether the above two measures produce an over- or under-recovery of a utility's total stranded costs cannot be finally determined until after July 1, 2007.

Model 1 Deficiencies

1. Failure to Compute Stranded Costs

WGES sees little merit to Proposal 1 because it would fail to meet the fundamental task of computing and quantifying stranded costs in the first instance.

2. Omission of Stranded Costs from Capped Rates

The model is also unworkable because it seeks to deal with stranded costs only through wires charges that are payable by customers who select competitive electricity suppliers. It would omit the recognition of stranded costs recovered or to be recovered through capped rates. By inference, the absence of customer switching would preclude the need to determine over/under collection of stranded costs. This is a fatal flaw.

The Restructuring Act contemplates recovery of stranded costs from both capped rates and wires charges, and the determination of over/under-recovery of stranded costs should come from both. The Act in Section 56-584 stipulates that "...each incumbent electric utility shall only recover its just and reasonable net stranded costs <u>through either capped rates</u> as provided in section 56-582 <u>or wires charges</u> as provided in Section 56-583...." (emphasis supplied).

Therefore, stranded costs are embedded and are recovered in capped rates, where there is no switching. Stranded costs are only unbundled for customers that choose competitive suppliers, a hallmark of a nonbypassable surcharge. Customers who purchase a premium product such as renewable energy from a competitive supplier have not switched. They still pay stranded costs through capped rates and not wires charges.

3. False Premise of Revenue-based Stranded Costs

The premise that stranded costs are only to be based on revenues collected from wires charges is false. Such revenues are transition charges that flow from a pre-determined amount of stranded costs for each incumbent utility at the start of restructuring in 2000 to July 1, 2007. In this case, we are dealing with the determination of stranded costs post- restructuring implementation. Stranded costs represent unmitigated lost value of generation related assets brought about by electricity restructuring. The process is based on asset valuation, analysis or other determinant basis. Therefore, stranded costs are a cost-based not revenue-based determination. Besides, it would be impractical to determine the real over/under recovery of stranded costs without first establishing the underlying total amount of stranded costs. Proposal 1 fails to satisfy this precept.

4. Potential Stranded Costs Deficiency

The model is further deficient because it purports to deal with expenditures to mitigate <u>potential stranded costs</u> and not actual stranded costs. The Restructuring Act does not contemplate the recovery of <u>strandable costs</u>. Instead, it speaks of the recovery of just and reasonable <u>net stranded costs</u>. The former is prospective and speculative in nature and the latter is inclusive of mitigation of known stranded costs identified ahead of time.

5. Failure to Meet Monitoring Obligation under the Restructuring Act

The model as proposed would not permit stakeholders or the Legislative Transition Task Force to discharge their obligation under the Restructuring Act Section 56-595 that reads as follows:

> (C) (iii) (A)fter the commencement of customer choice, monitor, with the assistance of the Commission, the Office of the Attorney General, incumbent electric utilities, suppliers, and customers, whether the recovery of stranded costs, as provided in Section 56-584, has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs.

Proposal 2 as Summarized by Staff

The main framework is:
To calculate just and reasonable net stranded costs compare asset values based on net present value cash flows that arise from remaining in a regulated market (cost plus a fair return) to the net present value cash flows that arise in a competitive market (over the life of the assets). From this amount subtract recoveries via capped rates (to the extent capped rates exceed actual costs including a fair return) and wires charges to determine the over- or under-recovery of just and reasonable net stranded costs.

1. Model 2 would Compute Stranded Costs as Intended

The fundamental basis of Model 2 is the calculation of stranded costs based on generation related asset valuation and the recovery of transition charges through capped rates or wires charges. It is a balanced approach that seeks to establish stranded costs first, set a recovery schedule and determine the over- or under-recovery of just and reasonable net stranded costs, at least annually, until the expiration of the transition period on July 1, 2007. The final recoverable amount for stranded costs should be known by June 30, 2007. And by July 1, 2007 and thereafter, there would be no opportunity to collect stranded costs through capped rates or wires charges by an incumbent utility company.

2. Opportunity to Terminate Capped Rates after January 1, 2004

The Act in Section 56-582 allows for a utility to end capped rates by petition or Commission action. The relevant portion reads as follows:

> (C) A utility may petition the Commission to terminate the capped rates to all customers any time after January 1, 2004, and such capped rates may be terminated upon the Commission finding of an effectively competitive market for generation services within the service territory of that utility....

Since the model would permit the calculation of total stranded costs for each incumbent utility and set a revenue recovery schedule, it would be easy to know the pace of recovery and the expiration of such costs. Therefore, it is quite conceivable to recover stranded costs on an accelerated basis through either capped rates with no switching or through wires charges under robust competition.

Under the two scenarios capped rates and wires charges could cease after January 1, 2004. The proposed Model 2 at least would allow for such a determination to be affirmatively made.

We recognize the issues of potential model complexity, data intensiveness and model assumptions. However, these are not demerits of model 2 but rather the inherent nature of establishing total stranded costs. Stranded costs calculations have been accomplished in other jurisdictions that have restructured including New York, Massachusetts, Pennsylvania and Rhode Island, to mention a few. It is not too late for each utility in Virginia to provide a stranded cost recovery plan. Such a plan should identify mitigation strategies, net out stranded costs collected from 2000 to December 2003, establish an annual recovery schedule from January 2004 to July 1, 2007 (with year-end adjustments) and identify potential early termination of capped rates. Model 2 would make that possible.

Respectfully submitted,

Ransome Owan

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April 18, 2003

Via Electronic Delivery Only

Susan D. Larsen, Deputy Director
Division of Public Utility Accounting
State Corporation Commission
1300 East Main Street
Richmond, VA 23218-1197

Re: Commonwealth of Virginia, ex rel. State Corporation Commission In the Matter of Developing Consensus Recommendations on Stranded Costs Case No. PUE-2003-00062

Dear Ms. Larsen:

WGES will be unable to attend the April 21 meeting. Permit us to submit written observations to comments instead. We plan to remain active in the process.

General
The present discussion is about conceptual approaches only. Based on the comments filed so far it would appear that further work would be needed to flush out the high-level approaches before the group. That said, it would still be problematic to present the joint-utility proposal (if that connection could be made) as a way to calculate stranded costs. It is instructive to read all the insightful comments provided. While parties are free to stake their positions, an honest debate should point to the correct approach to the problem, at the very least. The concept of lost revenues will not be lost in a calculation of stranded costs. While the Restructuring Act is silent on computing stranded costs, the LTTFs' charge and the Commissions' order are clear.

Evidence exists of generation-related assets and liabilities that were written off in 1999 as uncollectible through capped rates by some incumbents, after-tax charge to earnings were also made at that time and regulatory assets created to represent the amount recoverable from capped rates. It would seem that there is a body of information that could be shared in confidence to facilitate this process. To that end, the LTTF REQUESTED ACTION in No.6 speaks of a confidential pact to prevent "unauthorized disclosure of information regarding incumbent **utilities' stranded costs and amounts received to offset stranded costs** that is provided in confidence to the work group." (emphasis added).

The vexing question is what did each utility consider to be stranded costs prior to the commencement of transition in 2000? Revenues from both capped rates and wires charges should be compensatory of net stranded costs as ruled prior to restructuring. Perhaps, a lot of work could be reduced if the utilities could provide in confidence their pre-restructuring stranded costs estimates, write-offs taken (which would no longer be part of the new calculus), regulatory assets created and the amounts that have been collected to-date. Surely, one must have information regarding such an extraordinary item as stranded costs that permanently affected the utility regulatory bargain of long standing. The information provided would show what mitigation strategies were/are used to further reduce stranded costs and the expected amounts to be recovered from the breach of the regulatory bargain/contract between the utilities/shareholders and the Commission due to competition. The special case of no wires charges may have to be treated as unique.

The Restructuring Act merely allowed utilities to use whatever stranded cost proxies they liked and to structure revenue collection in capped rates and/or wires charges. This midway excise would recalibrate how much stranded costs are collected through July 1, 2007. There would be no changes in the revenue collection process and procedures already in place, namely capped rates or wires charge. Most importantly, doing this analysis (or by negotiations after a review of data/information) would permit the Commission, the utilities and the LTTF to ascertain if capped rates could be terminated for any utility after January 1, 2004 (with utility cooperation). The process will preserve revenue neutrality for incumbents during the transition period.

Comments on Selected Working Group Views

Dominion Virginia Power

We do not object to Dominion Virginia Power's (DVP) view that Staffs' methodology does not adequately capture the complexity of computing stranded costs. The method does not pretend to mask such complexities either. It is only an approach but a better approach to the problem of the "Virginia twist" to stranded costs treatment. DVP also mentioned the impact of default service on stranded costs calculation. Once stranded costs are recovered by July 1, 2007 and true default service goes into effect, then the issue of generation-related assets that are rendered uneconomic by competition ceases to be a problem. DVP further correctly cited the need for flexibility thus "...It is essential that rigidity not be incorporated in one component of the transition process that may unintentionally undermine the ultimate objective." (DVP page 5).

Will the utilities show any flexibility with regards to the stranded costs question? We beg to differ with the assertion that no actual determination of stranded costs is necessary. A month-to-month dependency on wires charges can not supplant the need to know the underlying amount of stranded costs. The revenue requirements of each utility through the transition period were set prior to restructuring. We are not aware of any suggestions to neither change that fact nor initiate a rate case, "even if the existing rates were believed to be too high." The apparent drumbeat and fear of impending doom, are just that.

Allegheny Power

It is possible to be sympathetic to the position of Allegheny Power (AP) due to its settlement that waived its rights to wires charges and asset transfer in August 2002, but only partially so. As AP sees it, "the MOU established capped rate levels for AP, and AP would <u>recover whatever stranded costs existed through capped rates</u>." (emphasis added). The recovery of <u>whatever</u> stranded costs that may exist is precisely the problem for all incumbent utilities in Virginia. Since AP is recovering stranded costs from capped rates and there is no competitive vigor in the marketplace, would that portion of stranded costs cease sooner than July 1, 2007? By DVPs' method, AP would not have to do anything since it has no wires charges. However, it would appear that APs' settlement might not fully obviate it from the over/under recovery question, functional separation notwithstanding.

Others

We believe that the comments that point to a stranded cost quantification solution where none existed before are in keeping with the wishes of the LTTF. This likeminded views were articulated by the Consumer Counsel, Constellation NewEnergy, TXI-Chaparral, the Virginia Citizens Consumer Council and Christian and Barton, LLP. The views of DVP, American Electric Power and those of the Cooperatives fall short of the mark and should be rejected. We do not object to the suggestions made by TXI-Chaparral to add, "just and reasonable, prudently incurred non-mitagable generation costs plus fair return" to Staffs' proposal. The single most important thing is how to forge a consensus and move forward given the gaps that have been identified.

Respectfully submitted,

Ransome Owan

Ransome E. Owan, Ph.D.
Director, Regulatory and External Affairs
Washington Gas Energy Services, Inc.

April 16, 2003

Susan Larsen
Deputy Director, Public Utility Accounting
Virginia State Corporation Commission
Tyler Building
1300 E. Main St.
Richmond, Virginia 23219

Dear Ms. Larsen:

Per the Commission Staff's instructions on April 10, 2003, Constellation NewEnergy, Inc. herby provides its initial comments to the Virginia stranded cost working group on the proposed conceptual models to be used to calculate net stranded costs. Constellation NewEnergy, Inc. expresses its appreciation of the Commissions efforts to facilitate the working groups efforts to quantify net stranded costs.

If you have any questions regarding these comments, please do not hesitate to call at 215-320-1164.

Sincerely,

Eric W. Matheson
Director, State Regulation
Mid-Atlantic Region,
Constellation NewEnergy, Inc.

Proposal # 1: "Dominion Virginia Power Proposal"

The methodology for calculating "just and reasonable net stranded costs" requires a utility to determine (1) whether there is over- or under-recovery of stranded costs collected through the wires charges from switching customers, and (2) the amounts it has expended from funds available under capped rates to mitigate potential stranded costs, less any additional expenditures that negatively impact such costs. Under (1), a company can compare the revenue actually collected annually from customers via the wires charges based on projected market prices to the revenue that would have resulted had wires charges been based on the actual market prices experienced during that year. If the revenue collected through the wires charges was greater than the revenue that would have resulted had the actual market price been correctly predicted, the wires charges were set too high, resulting in an over-recovery for that year. If the contrary is the case then there is under-recovery. In any event, whether the above two measures produce an over- or under-recovery of a utility's total stranded costs cannot be finally determined until after July 1, 2007.

Strengths of Methodology #1

The ability to calculate "Item one" in this methodology is rather uncomplicated. It would compare the projected market prices as defined in the wires charge proceeding and subsequent compliance filings, with the actual market prices during the time period. Presumably, this would calculate the actual **reduction in revenue during the transition period** resulting from customers switching to competitive service providers ("CSP's") and changes in market prices.

Weaknesses of Methodology #1

1. *Definition of stranded costs is not addressed.* This definition does not appropriately address the task at hand, namely, to calculate the just and reasonable **net stranded costs**. Our charge is not to quantify a reduction in **revenue** during the transition

period. Per the workgroup's last discussions, stranded costs refer to an incumbent electric utility's (net) **costs** that are unrecoverable due to restructuring and retail competition. More appropriately, this working group should be examining the generation assets and power purchase assets of the utilities and cooperatives to see if these assets are above or below market subsequent to the restructuring legislation, as well as considering various mitigation alternatives.

2. *"Potentially Stranded Costs" is not defined or described.* "Item 2" the above methodology does nothing to define or describe how to calculate "potentially stranded costs." Thus, we are left with no clear guidance on how to achieve the objective of the working group.

3. *Wires charge calculations are not an appropriate surrogate for stranded costs.* During the wires charge proceedings, the weaknesses of the wires charge mechanisms as a surrogate for stranded cost estimation was acknowledged by the administrative law judge. Specifically, the administrative law judge admitted in essence that the market price did not reflect the competitive retail price, but instead reflected the wholesale price of residual power sales resulting from displaced generation. As will be discussed later, this has the effect of significantly understating the competitive market price for retail service against which the CSP's must compete during the transition period. If the market price is understated, the wires charges will be overstated – thus potentially over-collecting the stranded costs, and ensuring that a competitive market will not be established in Virginia. From a practical standpoint, that is exactly what has happened to date in Virginia.

4. *Wires charge calculations do not properly net year to year over and under collections.* For each year, wires charges can only produce a zero or positive charge. It is entirely possible, and even probable in some jurisdictions, that wires charges would have been negative if not for the legislative requirement that they be zero or greater in any year. Thus, this mechanism fails by statute to meet any reasonable

definition of net stranded costs.

5. *Wires charge calculations do not allow for any mitigation of stranded costs.* Per the last meeting of the working group, net stranded costs referred to an incumbent electric utility's prudently incurred and verifiable stranded costs, the mitigation of which is beyond the control of such incumbent electric utility. Using a prescribed revenue stream, as would result from the methodology above, is static, and would embody no such mitigation. Examples of potential mitigation measures include (1) sales of generation assets, (2) decommissioning of poor performing assets, (3) expiration of power purchase contracts, (4) restructuring of existing power purchase contracts, (5) and adjustments to general and administrative expenses to adapt to the more competitive market.

6. *Methodology #1 does not allow for a timely determination of stranded costs.* The proposal put forward by Dominion Virginia Power would not provided any certainty going forward on the level of net stranded costs to be collected through the wires charges and bundled rates until after the transition period has expired. Therefore, consumers will not be able to commit to CSP's for any significant period of time. This could cause consumers to come in and out of the market based on the wires charge "du jour" for any give year. This is not conducive to the development of a competitive market, and will do little to attract competitive suppliers to the Virginia market.

Proposal #2: "Staff/Consumer/Retail Supplier Proposal"

This proposal seeks to compare the actual and projected generation cost of the utility or cooperative to the actual or projected market price. This model includes a provision for demonstrating the existing average cost of providing generation service by the incumbent utility or cooperative, as well as the projected average cost resulting from mitigation or changes in the utility portfolio over time. Net stranded costs would be calculated by subtracting market price from the actual or projected cost of providing generation services to customers, after mitigation measures. Any wires charge collections to date would be credited to this calculation of net stranded costs embedded in existing bundled rates.

Strengths of Methodology #2:

1. *The methodology addresses the issue of stranded costs.* This methodology addresses the core issue of stranded cost determination, not some perception of guaranteed revenues during a defined transition period.

2. *This model is not static over time.* Use of methodology #2 will more accurately reflect the change in generation portfolio over time. For example, it would be unjust and unreasonable to assume that Dominion should be able to include in its stranded cost portfolio an alleged above-market power purchase contract that expires in 2005 after such date. Similarly, it would be illogical to assume that an inefficient, above market generation asset should continue to be operated into perpetuity or beyond its life expectancy.

3. *This model includes appropriate stranded cost mitigation provisions.* It is in the public interest for utilities and cooperatives to mitigate their stranded costs to the extent necessary to bring their generation assets in-line with the competitive market. For example, the company can sell assets to the competitive market if the company can achieve a higher return for its shareholders by transferring these assets to a company that can more efficiently and safely operate that particular facility or facilities. Similarly, the utility can seek mutually beneficial solutions with power purchase contract parties to renegotiate certain power purchase contracts. General and administrative costs can be realigned to meet the competitive market pressures. Poor performing generation assets can be sold or shut down earlier to accelerate stranded cost recovery. Asset life of existing low cost units can be extended, such as nuclear plants, thus reducing the underlying depreciation rates and net book values of

aggregate generation assets embedded in existing rates.

4. *Robust examination of market rates can be achieved.* It is important that market prices are carefully crafted to accurately reflect the competitive realities of any stranded cost determination. For example, if utility costs are reflective of retail prices, then they must be compared to market prices that are reflective of retail prices. If, on the other hand, utility costs are reflective of only wholesale costs of generation, then they must be compared to wholesale market prices for the same product. As a further clarification, wholesale costs of the utility will need to be compared to a full requirements wholesale market product. More simply stated, the parties much ensure that any evaluation compares "apples to apples." The use of methodology #2 will permit this more robust examination, whereas, it is well established in the record in Virginia that methodology #1 does not achieve this objective.

Weaknesses of Methodology #2

1. *Calculation of net stranded costs is complex and data intensive.* The methodology described above will not be easy. It will require the utilities to provide vital information to the understanding of this issue, and require a range of assumptions to be made and evaluated. It is likely that this process will result in various parties providing their own estimates of these assumptions regarding market prices, mitigation measures, interpretation of prudence, to name a few items. The LTTF can then evaluate the merits of each party's evidence and draw their own reasonable conclusions, and make recommendations based on the evidence to the Legislature. While admittedly this is not easy, the effort is necessary in order to ensure an outcome that is in the public interest. In fact, in many cases where parties entered into very similar stranded cost proceedings, the parties were often able to reach settlement on the appropriate level of stranded costs or benefits. In so doing, the competitive market place benefited from the price and regulatory certainty that a settlement can provide to market participants.

VIA E-Mail - 04/18/2003

Susan,

Unfortunately, we will not be able to attend on Monday, but we are very interested and concerned about the outcome in this matter. Clearly, exit fees are a counter-productive method of recovery, particularly when the costs can not be quantified, if at all, prior to a meaningful migration occurring.

Please keep us advised on the progress in this matter.

Thank you

Craig Goodman

Craig G. Goodman
President
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(202) 333-3288
www.energymarketers.com

From: Jack Greenhalgh [jack@jackgreenhalgh.com]
Sent: Friday, April 18, 2003 9:40PM
To: Susan Larsen
Subject: Re: Stranded Cost meeting Monday

New Era Energy will be unable to attend Monday's meeting. We agree with the comments submitted by Constellation New Energy, Inc.

Jack Greenhalgh
New Era Energy, Inc.
jack@neweraenergy.com
757 481-0450 fax 757 496-5594
Have a great day!
Good afternoon:

STAFF'S E-MAIL DATED APRIL 30, 2003 AND WORK GROUP PARTICIPANT RESPONSES

Attachment 10

Susan Larsen

From: Susan Larsen
Sent: Wednesday, April 30, 2003 7:54 AM
To: Michelle Gunzburger; Anthony Gambardella; August Wallmeyer; Barry Thomas; Cliona Robb; Craig Goodman; Cynthia Menhorn; Daniel M. Walker; David Wagner; Edward Flippen; Edward Petrini; Eric Matheson; Frank Munyan; Frann Francis; Glenn Simpson; H. Master; Irene Leech; Jack Greenhalgh; James Kimball; John Pirko; John R. Howells; Karen Bell; Kenneth Hyrwitz; Lex Bailey; Meade Browder; Michael Kaufmann; Michael Swider; William Thomas; Paul Haynes; Paul Hilton; R.L. Terpenny; Randall Griffin; Ransome Owan; Robert Omberg; Robert Sloan; Stacey Rantala; Stewart Farrar; Taff Tschamler; Telemac Chryssikos; Thomas Kinnane; Tom Nicholson; William Moore
Subject: Stranded Cost Work Group

Yesterday was the Stranded Costs Work Group's final meeting. As discussed, Staff would like written comments on several issues which have not yet been addressed in writing or there has been a change or clarification that may require further comments. **All comments should be e-mailed to me by 5 p.m., Thursday, May 8, 2003.** They will be posted to the Economics and Finance section of the Commission's website the following day.

1) LTTF requested action #9 reads: "Include in its reports to the LTTF any recommendations for legislative or administrative action that the Commission, the work group, or both, determine to be appropriate in order to address any overrecovery or underrecovery of just and reasonable net stranded costs."

Please discuss whether the definitions and/or methodologies discussed by the work group might require any action as contemplated by Requested Action #9. Discuss what action may be necessary, the timing of that action, and why it is necessary.

2) Comments regarding the proposal put forth by Ed Petrini.

3) Comments on the Staff proposal discussed at today's meeting.

4) Comments on the clarifications of Dominion's proposal.

Stranded Costs earinings test ... | Dominion Virginia Power - Prop... | stranded costs Ed Petrini's me...

Susan Larsen
Deputy Director
Public Utility Accounting
Virginia State Corporation Commission
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sdlarsen@scc.state.va.us

Stranded Costs – An Accounting Perspective

An alternative method that would indicate annual recoveries of stranded costs throughout the transition period is an accounting approach based on an earnings test mechanism. This mechanism could also be used to calculate the level of potential stranded cost exposure existing during each earnings test year. This approach would not provide for an upfront calculation of what total stranded costs are estimated to be, but could work in conjunction with the other proposed methods by providing stranded cost recovery information.

It is important to define stranded cost terms relative to this accounting approach:

- **Recovery of stranded costs**: Recovery of stranded costs occurs throughout the capped rate period to the extent actual earnings exceed costs plus a fair return. These recoveries can be calculated and monitored using the earnings test mechanism.

- **Actual stranded costs**: Defined as the underrecovery of just and reasonable generation costs in a competitive environment. Actual stranded costs would occur after the termination of capped rates and wires charges if actual generation costs exceed market prices.

- **Potential stranded costs**: Defined as the annual stranded cost exposure during the capped rate period, assuming all customers are paying market rates for generation service. This amount is represented by the difference between the recalculated, cost-based unbundled generation rates (at a fair return) less the actual market rate for the applicable year, times total annual sales.

Earnings test information is already required to be filed by IOU's under the Commission's existing rate case rules and AIF requirements. Earnings tests only recognize limited accounting or regulatory adjustments to per book amounts, and do not encompass going forward adjustments. Generally, earnings test adjustments restate per book results in order to reflect differences between GAAP and how costs are recognized for ratemaking purposes. It would be necessary to agree upon an appropriate fair rate of return to use as a benchmark ROE from which to measure earnings available for stranded cost recovery.

A bundled earnings test should be used until such time as bundled, capped rates are terminated. It is proper to use a bundled earnings test since all earnings produced under bundled, capped rates that are in excess of actual costs plus a fair return can be used to mitigate stranded cost exposure.

The determination of potential stranded costs will require a functionalized cost of service study that separates out the generation business. The cost of service study would incorporate the earnings test adjustments applicable to the test period. Actual generation costs for the test year including a fair return would then be used to calculate current, cost-based, unbundled generation rates by customer class. These generation rates would be compared to market-based rates applicable to the test year to calculate the potential stranded cost exposure for that year.

Throughout the transition period, comparisons can be made between stranded cost recoveries and potential stranded cost exposure. This will provide insight into the success of mitigation efforts, and the likelihood of whether an over or underrecovery of stranded costs will occur. By the end of the capped rate period, the earnings tests will have quantified the cumulative net recoveries of stranded costs, and we will be able to more accurately determine any stranded cost exposure going forward at that time, based on the same potential stranded cost calculations. Continued earnings monitoring after the termination of capped rates on the unbundled generation business could provide a calculation of actual stranded costs or benefits on an annual basis.

PROPOSAL 1

Dominion Virginia Power's proposed methodology for monitoring "just and reasonable net stranded costs" would require a utility to calculate and report to the LTTF, for each year of the transition period, (1) whether there was an over- or under-recovery of stranded costs collected through the wires charges from switching customers and, if so, the amount thereof, (2) the company's actual "above-market" or "potential" stranded costs exposure under capped rates, (3) the amounts it has expended from funds available under capped rates to mitigate potential stranded costs, and (4) additional expenditures that negatively impact (increase) such costs during the transition period.

To make the determination required under (1), a company would compare the revenue collected annually from customers via the wires charges, based on the projected market prices established by the Commission, to the revenue that would have resulted had wires charges been based on the actual market prices experienced during that year. Projected market prices are based on actual forward market transactions and information prevailing at the time the Commission establishes wires charges, if any, to be in effect for the next calendar year. Actual market prices are based on actual market transactions ("settlement" or "spot" prices) and information prevailing at the time the energy could be delivered for sale. If the revenue collected through the wires charges was greater than the revenue that would have resulted had the actual market price been correctly predicted, the wires charges were set too high, resulting in an over-recovery for that year. If the contrary was the case, then there was an under-recovery.

Under (2), a utility would track the annual potential stranded costs exposure associated with customers still paying capped rates during the transition period. After the close of each year, the Company would compare actual market prices experienced during that year (using the same data as above) to the Company's unbundled generation rate, and a determination would be made of the potential total revenue impact had all sales been made at those market prices rather than at capped generation rates. This calculation would yield the potential stranded costs exposure during each year of the transition period.

Under (3), a utility would annually report to the LTTF the amounts it has expended for mitigation of potential stranded costs and, in (4), expenditures that add to potential stranded costs.

While these measures will provide the LTTF with annual information to monitor stranded cost recovery and the Company's potential stranded cost exposure, the over- or under-recovery of a utility's total stranded costs cannot be finally determined until after July 1, 2007. Until that date, the market prices existing at the end of the transition period cannot be determined.

#159930

- Section 56-595.C (iii) of Virginia's Electric Utility Restructuring Act ("Act") provides that the members of the Legislative Transition Task Force ("LTTF") " ... shall: ... monitor ... whether the recovery of stranded costs, as provided in § 56-584, has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs.

- To monitor an "over-recovery" or "under-recovery," the LTTF must determine and compare two amounts: first, the amount that has been, or will be, available for recovery of just and reasonable net stranded costs, and, second, the amount of just and reasonable net stranded costs.

- Section 56-584 of the Act provides for two sources of revenue for the recovery of just and reasonable net stranded costs -- capped rates and wires charges.

- Thus, the amount that has been, or will be, available for recovery of such costs is the net revenue collected from wires charges and capped rates. Because the incumbent utility must collect sufficient revenue to recover its costs of providing service, the net revenue available for the recovery of just and reasonable net stranded costs is the revenue from capped rates and wires charges in excess of the revenue needed by the utility to recover its costs of providing service (*i.e.*, the utility's revenues in excess of its "revenue requirement").

- The following approach recognizes both sides of the inquiry required of the LTTF – *i.e.*, (i) the amount of just and reasonable net stranded costs and (ii) the amount available for recovery of such costs through wires charges and capped rates.

    To calculate just and reasonable net stranded costs compare asset values based on the net present value of the difference between the revenues that arise from remaining in a regulated market (cost plus a fair return) and the revenues that arise in a competitive market (over the life of the assets). From this amount subtract revenues via capped rates (to the extent capped rates exceed actual and likely costs including a fair return) and wires charges to determine the over- or under-recovery of just and reasonable net stranded costs.

- The above approach represents an acceptable, administrative methodology for the calculation of both just and reasonable net stranded costs and their recovery under the Act. By reference to the "regulated market (cost plus a fair return)," the methodology incorporates traditional ratemaking concepts in a regulated environment, including consideration of a utility's regulated cost of service used in setting "just and reasonable" rates, and including concepts of "prudence," mitigation, verification, and the "netting" of stranded costs and margins. The methodology properly requires consideration of the useful life of assets.

- As is true of any administrative method of determining stranded costs, the above approach involves estimates based on long-term revenue and cost projections. Such estimates are data-intensive and highly sensitive to the underlying assumptions and models used in making them. Long-term projections, however, are almost always used, implicitly or explicitly, in valuing assets for commercial purposes. Reasonable forecasts of items affecting such calculations and the development of estimates under reasonable scenarios would be required.

- Incumbent electric utilities must make annual informational filings ("AIFs") that include specified financial information with the State Corporation Commission. The Commission reviews such AIFs for compliance with Commission requirements for accounting and ratemaking treatment of costs and revenues. As approved by the Commission, AIFs would provide an acceptable basis for calculating a utility's historical cost of providing service and any revenues in excess of those costs that may be available for recovering stranded costs.

Response of Dominion Virginia Power to Commission Staff's "Stranded Costs – An Accounting Perspective" Method and the Virginia Committee for Fair Utility Rates' Method

Commission Staff's "Stranded Costs – An Accounting Perspective" Method

On April 29, 2003, the Commission Staff presented its methodology titled "Stranded Costs – An Accounting Perspective." According to the Staff, "[r]ecovery of stranded costs occurs throughout the capped rate period to the extent actual earnings exceed costs plus a fair return."

The Commission Staff's "Accounting Perspective" method is an attempt to reinstitute "ratemaking" during the capped rate period. Specifically, the Staff proposes to cap a utility's earnings at a Commission-approved rate of return and to treat any earnings above such return as a "recovery of stranded costs." The determination of this rate of return would require a stipulation or hearing on the proper ratemaking treatment of a utility's revenue, expenses, and investment. While the Staff proposes using each investor-owned utility's Annual Informational Filing ("AIF") as the basis for determining a utility's earnings, the inevitable disagreements would have to be resolved in a Commission proceeding.

The Commission's Rules Governing Utility Increase Applications and Annual Informational Filings ("Rules"), 20 VAC 5-200-30, are comprehensive. They specify what accounting schedules must be filed and what adjustments are permitted. For example, the Rules provide that an AIF filing cannot incorporate adjustments that were not approved by the Commission in a company's last rate case. Given that Dominion Virginia Power's 1996 case was a settlement in which accounting disputes were not decided, the Company's last relevant rate case was in 1992. *See Virginia Electric and Power Company, 1995 Annual Informational* Filing, Case No. PUE-1996-00036, and *Commonwealth of Virginia, At the relation of the State Corporation Commission, Ex Parte: Investigation of Electric Utility Industry Restructuring*;

Virginia Electric and Power Company, 1998 S.C.C. Ann. Rept. 322 (Aug. 7, 1998). *See also Application of Virginia Electric and Power Company, For an expedited increase in rates*, Case No. PUE-1991-00047, 1992 S.C.C. Ann. Rept. 291 (Dec. 29, 1992). Surely, the issues decided in 1992 differ from what is likely to be raised and decided in 2003. Dozens of new accounting, capital structure, and rate of return issues could be raised by the Staff and parties. In fact, the Commission formally approved a rule in 2000 that expressly recognizes the right of the Staff or of any party to raise new issues in AIFs. *See Commonwealth of Virginia, At the relation of the State Corporation Commission, Ex Parte: In the matter of Adopting Additions and Amendments to the Commission's Rules Governing the Filing of Utility Rate Increase Applications*, Case No. PUA-1999-00054, 2000 S.C.C. Ann. Rept. 140 (July 28, 2000).

The Virginia Electric Utility Restructuring Act (the "Act"), Va. Code §§ 56-576, *et seq.*, provides utilities with the flexibility to recover stranded costs over a reasonable period of time tailored to each utility. The Commission recommended this approach to the SJR 91 Subcommittee when the Restructuring Act was being considered. The Commission emphasized the importance of flexibility by stating "[i]f the General Assembly decides that at least some portion of stranded costs should be recoverable, we suggest a legislative approach to the determination and recovery of such costs that is specifically aimed at maintaining reasonable and necessary flexibility with respect to policy implementation and administration. We believe that this flexibility is critical to serving the public interest of Virginia in that such a process entails substantial complexity and uncertainty, poses potentially significant public impacts, and must address the unique circumstances of each utility . . . (emphasis added)." Comments from introduction to "SCC Draft Stranded Costs/Benefits Legislation," July 1998.

As enacted, the Restructuring Act provides for this flexibility. Specifically, the Act's capped rate provisions offer a clear incentive to electric utilities to reduce costs by July 1, 2007, in order to bring generation costs in line with the competitive generation market. To the extent utilities decrease their costs and increase their earnings, they have the opportunity and incentive to mitigate stranded costs in the exercise of their business judgment. These opportunities and incentives have been successful. For example, Dominion Virginia Power has spent or otherwise mitigated over $1 billion in generation-related costs since enactment of the Act. By any measure, it is making significant progress toward being an effective generation competitor by July 1, 2007.

Despite this, the Commission Staff now proposes to destroy the opportunities and incentives provided by the Act and replace them with a heavy burden. Instead of working to reduce costs, the Company would be forced to defend a rate case each year.[1] Instead of having the flexibility to negotiate with non-utility generators ("NUGs"), the Commission will assume that the Company has collected and spent each dollar it earns over a Commission-approved rate of return on stranded costs mitigation. In short, the Staff wants to "manage" the Company's mitigation efforts by requiring it to spend every available dollar on such efforts regardless of other priorities.

The Staff's proposal advocating rate of return regulation contradicts the Act. Virginia Code § 56-581 provides that " . . . subject to the provision of this chapter after the date of customer choice, *the Commission no longer shall regulate rates and services for the generation component of retail electric energy sold to retail customers.*" (Emphasis added.) The Virginia

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[1] In fact, the Staff's approach raises the possibility that such proceedings might continue well <u>beyond</u> the capped rate period: "Continued earnings monitoring after the termination of capped rates on the unbundled generation business could provide a calculation of actual stranded costs or benefits on an annual basis." No purpose or justification under the Act for this extended monitoring is offered or apparent.

Code could not be more clear. In fact, the General Assembly set the Company's rates and, as discussed on page 7, provided for the Commission to revisit those rates only under the limited circumstances set forth in § 56-582.

Indeed, the notion that a utility's revenue requirement might be determined on an annual basis during the transition period, except at the request of the utility, was never proposed during the years of debate leading up to the Act. In fact, the Act compels just the opposite conclusion, as several provisions make clear. For example, except for the Company, every utility has the option of seeking a "going-in" rate case to have its capped rate levels fixed by the Commission. No other party, not even the Commission on its own motion, is permitted under the Act to initiate such a rate case, even if the existing rates are believed to be too high. Despite this, the Staff's "Accounting Perspective" incorporates a series of rate cases as its key feature. This method may involve fewer accounting adjustments than a proposed increase, but the Staff and parties would inevitably disagree over the major issue inherent in every rate case – a fair rate of return.

The Commission Staff is advocating a limit on the Company's flexibility just as the Company has begun to make progress in mitigating its potential stranded costs. For example, as a result of the Act, the Company has written off approximately $340 million in generation-related regulatory assets (in addition to the $220 million write-off approved in the 1998 rate case settlement).[2] The Company also has paid or otherwise mitigated approximately $370 million related to NUG contracts to reduce its above-market generation costs and has reduced operating costs another $100 million through efficiency measures. The Company has spent hundreds of millions of dollars on new transmission, distribution, and generation prospects

[2] These amounts are Virginia jurisdictional.

and approximately $200 million for nuclear reactor vessel head replacements. Additionally, on April 18, the Company, the U.S. Environmental Protection Agency and five states announced a comprehensive agreement resolving disputes arising under the Federal Clean Air Act. Under the agreement, the Company will invest $1.2 billion in environmental projects, including advanced emissions control systems at the Chesterfield, Chesapeake, Yorktown, Bremo Bluff and Possum Point power stations in Virginia and the Mount Storm and North Branch power stations in West Virginia. Although the Company will make the expenditures through 2013, a considerable portion of them will be incurred during the capped rate period. This includes approximately $628 million in advanced technology to reduce nitrogen oxide emissions by 66 percent from 2000 levels. All this activity was made possible by the considerable flexibility afforded by the Act – flexibility that would be lost under rate of return regulation and stranded costs recovery "managed" by the Commission Staff.

Virginia Committee for Fair Utility Rates' Method

On April 29, 2003, Ed Petrini, counsel to the Virginia Committee for Fair Utility Rates ("VCFUR"), also presented a proposal to the work group. He described the VCFUR proposal as a combination of the so-called "Spinner method" and Commission Staff's "Accounting Perspective." The Company discussed the problems associated with Mr. Spinner's proposal in its comments filed on April 16, 2003, and its comments on the Staff's "Accounting Perspective" are set forth above. As made clear in those analyses, both proposals suffer severe shortcomings and do not comply with the Restructuring Act or with the directive of the Commission on Electric Restructuring (formerly the Legislative Transition Task Force) to develop an appropriate methodology for monitoring the over- or under-recovery of stranded costs. Mr. Petrini's effort to combine the two does not improve them. Indeed, his suggested approach incorporates an opportunistic modification that demonstrates what Mr. Spinner has admitted, i.e., his methodology would be "fraught with controversy every step of the way."

First, as Mr. Petrini says, the Act provides two sources of revenues for the recovery of just and reasonable net stranded costs--capped rates and wires charges. However, he then states that:

> . . . the amount that has been, or will be, available for recovery of such costs is the net revenue collected from wires charges and capped rates. Because the incumbent utility must collect sufficient revenue to recover its costs of providing service, the net revenue available for the recovery of just and reasonable net stranded costs is the revenue from capped rates and wires charges in excess of the revenue needed by the utility to recover its costs of providing service (*i.e.,* the utility's revenues in excess of its "revenue requirement").

Here, Mr. Petrini's method, like the Commission Staff's "Accounting Perspective," seeks to impose traditional rate of return regulation.[3] How much does a utility "need" to "recover its costs of providing service"? What is its "revenue requirement"? These are questions and concepts that frustrate the Act's deregulation of generation.

Mr. Petrini ignores the Act's most critical feature: the utilities' discretion to use available funds from the capped rates and wires charges, without the burden of Commission rate cases. Simply put, the Act created a "budget" for utilities for the entire capped rate period. How well they manage their budgets will be known on July 1, 2007. Utilities bear the risks of whether they will become competitive generators (the final results are unknowable until the end of the capped

[3] Later portions of his proposal reinforce the impression of nostalgia for the old ways of regulation. Mr. Petrini candidly acknowledges that his approach "incorporates traditional ratemaking concepts in a regulated environment, including consideration of a utility's regulated cost of service used in setting 'just and reasonable' rates, and including concepts of 'prudence,' mitigation, verification...."

rate period), but they also have the flexibility to make and implement the best business decisions they can under this structure, without "second-guessing" by the Commission and others.[4]

As we have noted above in the Company's response to the Commission Staff, the Act imposed numerous strictures on the utilities, the Commission, and customers, consistent with those principles. First, capped rates can be examined and changed only for limited reasons: recovery of fuel costs, tax changes, financial distress of a utility beyond its control,[5] or a one-time change in non-generation rates under the special circumstances of § 56-582.C. Wires charges are reset only once a year, despite the vagaries the market may exhibit in the meantime.

Most significantly, many utilities were permitted to file an initial rate case under the Act for the purpose of establishing their capped rates, and the Commission was directed to decide such cases by giving "due consideration, on a forward-looking basis, to the justness and reasonableness of rates to be effective for a period of time ending as late as July 1, 2007." Thus, the rates fixed at the beginning of the capped rate period were to be considered just and reasonable for the entirety of that period. By necessary implication, the existing rates for the Company, which was denied the option of a similar rate case, were legislatively determined to be just and reasonable for the same time frame. Yet, Mr. Petrini now proposes to inquire into how much utilities "need," to examine periodically their "revenue requirement" during the capped rate period.[6] These pseudo rate cases are not sanctioned under the Act.

[4] Of course, the Company has already offered in its proposal methodology to report annually to the LTTF (1) any over- or under-recovery associated with wires charge revenues; (2) the Company's potential stranded costs exposure; (3) the amounts spent on mitigation of stranded costs; and (4) additional expenditures that increase such costs.

[5] This provision alone clearly means that no other entity may seek to reduce capped rates.

[6] Mr. Petrini states that the Annual Informational Filings made by incumbents "would provide an acceptable basis for calculating a utility's historical cost of providing service and any revenues in excess of those costs that may be available for recovering stranded costs." With all respect to Mr. Petrini, AIFs are simply not recognized in the Restructuring Act, and may not be used as a mechanism to examine, or establish, a utility's "revenue requirement" during the capped rate period.

Second, Mr. Petrini describes the central concept of his approach as follows:

> To calculate just and reasonable net stranded costs compare asset values based on the <u>net present value of the difference between the revenues that arise from remaining in a regulated market</u> (cost plus a fair return) <u>and the revenues that arise in a competitive market</u> (over the life of the assets). From this amount subtract revenues via capped rates (to the extent capped rates exceed actual and likely costs including a fair return) and wires charges to determine the over- or under-recovery of just and reasonable net stranded costs.

(Emphasis added.)

By contrast, Mr. Spinner's method was described by Staff as follows:

> To calculate just and reasonable net stranded costs compare asset values based on <u>net present value cash flows that arise from remaining in a regulated market</u> (cost plus a fair return) <u>to the net present value cash flows that arise in a competitive market</u> (over the life of the assets). From this amount subtract recoveries via capped rates (to the extent capped rates exceed actual costs including a fair return) and wires charges to determine the over- or under-recovery of just and reasonable net stranded costs.

(Emphasis added.)

The underscored portions of each passage highlight the critical change Mr. Petrini has made to Mr. Spinner's method. In brief, Mr. Petrini would calculate the net present value of the <u>difference</u> between two cash flows, while Mr. Spinner would subtract the net present value of the competitive cash flow from the net present value of the regulated cash flow. In making this seemingly subtle modification, Mr. Petrini demonstrates how Mr. Spinner's methodology may be manipulated to produce a given result.

That is, it is not correct to assume, as Mr. Petrini does, that the appropriate discount rate to be applied to cash flows from a regulated enterprise is equal to the discount rate applied to cash flows from a competitive environment. The risks are quite different, and the competitive flows must therefore be accorded a higher discount rate to recognize that fact. Mr. Petrini surely is aware of this principle, and his attempted disregard of it shows that every aspect of the Spinner methodology would be ripe for endless maneuvering to "massage" the numbers to reach specific goals of the various parties.

Finally, Mr. Petrini acknowledges that his method would require "estimates based on long-term revenue and cost projections. Such estimates are data-intensive and highly sensitive to the underlying assumptions and models used in making them." As the Commission and its Staff have noted when addressing similar past proposals, problems such as these constitute additional significant reasons for not adopting such an approach. *See* Appendix A to Response of Virginia Electric and Power Company to Commission's Order Establishing Proceeding. The General Assembly had an opportunity to incorporate concepts such as Mr. Petrini's into the Restructuring Act in 1998 and 1999; it clearly did not and for good reason. They are inconsistent with the legislative background. Indeed, the Company knows of no consideration by the General Assembly or participants in the General Assembly's process of such a "twisted" methodology.

Response of Dominion Virginia Power to
Action Contemplated by Paragraph 9 of the LTTF Stranded Cost Resolution

Proposal 1

The methodology proposed by Dominion Virginia Power in Proposal 1 is consistent with the Virginia Electric Utility Restructuring Act (Act) and may be implemented by appropriate resolution adopted by the Commission on Electric Utility Restructuring (CEUR). The resolution to implement Proposal 1 may, pursuant to Section 56.595(C)(iii), provide for appropriate administrative action by the State Corporation Commission and all incumbent electric utilities requiring that the monitoring information called for in Proposal 1 be provided annually to the CEUR.

With Regard to the (1) Spinner Methodology as Supplemented by the Staff Accounting Perspective Earnings Test, as well as (2) the Petrini Methodology

The Spinner Methodology, either on its own or as supplemented by the Staff Accounting Perspective Earnings Test, (and as revised by the Petrini Methodology) is not consistent with the Act. These methodologies would provide for a utility-by-utility stranded cost quantification determination as well as a process which is equivalent to an annual rate case for each utility. During the 1998-1999 consideration of the Stranded Costs issue by the SJR 91 Subcommittee, as well as during 1999 when the General Assembly enacted the Act, methodologies like these were specifically considered and rejected. As a result of the inconsistency with the Act, the implementation of these proposals would require substantial amendment to the Act. It will be necessary for the legislature to amend the Act to establish a process to implement the these methodologies, since nothing in the present Act provides for authority to proceed under them. In fact, in many instances, the provisions of the Act are in conflict with the activities that would be necessary under these methodologies. Since the State Corporation Commission has no inherent powers to carry out these methodologies and is provided no authority to do so under the Act, legislation would be required. Unless the CEUR determines that it has the staff and procedures to carry out these methodologies itself, it is logical to assume that there will be a proposal for the State Corporation Commission, through appropriate proceedings, to carry them out.

It is useful to examine what issues would have to be resolved through legislation for the State Corporation Commission to have authority and direction to carry out these methodologies. The list would include:

- A determination as to the date upon which Stranded Costs are to be determined - 1998, 1999, 2000, 2001, 2002?
- Will Stranded Costs be quantified once or periodically between now and 2007?
- Do these methodologies apply to all incumbent electric utilities?

- In making the Stranded Costs determination under these methodologies, what is the appropriate time period for projections: the remaining useful life of generation facilities, 10 years, 20 years, 30 years?

- What impact on this determination do "stranded benefits" have either before July 1, 2007 or after July 1, 2007?

- How will discount rates be determined?

- In determining "market rates" what methodology will be used and what impact on that methodology will there be by use of the "market rate" determination features under default service?

- What will be the impact of the default service obligation of an incumbent electric utility on "market rates"?

- What will be the impact of capital obligations and operating expenses undertaken or incurred by an incumbent electric utility since the passage of the Act?

- How will a "fair return" be determined and what effect will the deregulated environment created by the Act have on that determination?

- In making the "cost of service" determination, will this be done either with or without regard to the passage of the Act?

- Will there be any limitations on the accounting adjustments or issues that can be raised in the process of determining cost of service or a fair return?

- When conducting the earnings test contemplated, what is period of time for which the earnings test will begin – 1998, 1999, 2000, 2001, 2002?

- Is the assessment of earnings to be made annually or over some other period? Is the earnings test for bundled rates (including distribution and transmission rates) or only unbundled generation rates?

- Does the earnings assessment terminate in 2007 or continue thereafter?

CONCLUSION

If the legislature chose to amend the Act to provide the necessary authority and direction to implement the Commission Staff's and VCFUR's methodologies, it follows that there are other issues that logically should also be considered by the legislature for amendments. They include:

- Should legislation authorize a process for an increase or decrease in capped rates depending upon information determined pursuant to this process?

- Should legislation authorize a process for the capped rate period to be extended or shortened dependent upon the results of this process?

- Should legislation authorize a process for an increase or decrease in the wires charge or for extending or shortening the period for a wires charge?

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STRANDED COST COMMENTS – MAY 8, 2003

VIRGINIA ELECTRIC COOPERATIVES
Case No. PUE-2003-00062

On April 30, 2003, Commission Staff requested written comments on several issues that have not yet been addressed in writing or regarding which there has been a change or clarification that may require further comments. The following comments on the issues identified by Commission Staff are submitted on behalf the Virginia Electric Cooperatives.

1) Comments on the clarifications of Dominion's proposal.

The Dominion Virginia Power ("DVP") proposal was clarified by adding the following two sentences to the second paragraph of the proposal:

> Projected market prices are based on actual forward market transactions and information prevailing at the time the Commission establishes wires charges, if any, to be in effect for the next calendar year. Actual market prices are based on actual market transactions ("settlement" or "spot" prices) and information prevailing at the time the energy could be delivered for sale.

These two additional sentences provide an appropriate clarification of the DVP proposal. DVP has simply clarified the distinction between the "projected" market prices established by the Commission each year for the following year, and "actual" market prices, which reflect a look back at the market prices that were in fact available during that same year. Recognizing and understanding this distinction are essential to the methodology proposed by DVP. This addition to DVP's proposal is beneficial and consistent, changing essentially nothing of the thrust of the DVP proposal.

The DVP approach continues to provide for a year-to-year review of stranded costs recovery and avoids speculative projections, estimation and guesswork. The Cooperatives believe that the DVP methodology continues to be consistent with the spirit and the letter of the Restructuring Act and that it fully accommodates the majority positions expressed by the SJR 91 Drafting Group, the subcommittee as a whole and the General Assembly. As such, the Cooperatives continue to support strongly the DVP proposal over any other proposal considered or discussed to date.

2) Comments regarding the proposal put forth by Ed Petrini.

The document prepared by Mr. Edward Petrini, as counsel to the Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates, does not represent a new proposal. Mr. Petrini's offering is merely a restatement of the Commission Staff proposal presented by Mr. Howard Spinner, with some added emphasis and embellishment by Mr. Petrini. As such, this proposal continues to suffer from the inadequacies discussed in prior comments provided by the Cooperatives, DVP, AEP, the Virginia Independent Power Producers and others.

The proposed methodology summarized by Mr. Petrini continues to be inconsistent with the spirit and the letter of the Restructuring Act, and implementation still would require that many of the tasks and analyses specifically rejected by the SJR 91 Drafting Group, the subcommittee and the General Assembly be undertaken. In addition, the method advocated by Staff would require either consensus or a regulatory mandate regarding the methodology for describing the future market and forecasting future market prices, the life of the assets, and the discount rate to be used over the period of the forecast. The Cooperatives continue to believe that any projection of total stranded costs, coupled with stranded cost recovery based on a re-evaluation of what has occurred in the past few years and highly speculative long-term future market projections, could prove disastrous.

3) Comments on the Staff proposal discussed at today's (April 29, 2003) meeting.

At the April 29, 2003, meeting of the work group, Staff offered what it described as an alternative method to measure annual recoveries of stranded costs throughout the transition period by way of "an accounting approach based on an earnings test mechanism." According to Staff, this alternative mechanism also could be used "to calculate the level of potential stranded cost exposure existing during each earnings test year."

Staff's mechanism calls for a determination of all earnings produced under bundled, capped rates that are in excess of actual costs plus a fair return, which would be regarded as the earnings considered available for stranded cost recovery. Staff's proposed approach would require agreement on an appropriate fair rate of return to use as a benchmark ROE from which to measure these "available" earnings. The mechanism proposed by Staff would rely on earnings test information that investor-owned utilities ("IOUs") are currently required to file annually under the Commission's rules and AIF requirements, and a *bundled earnings test* would be used until such time as bundled, capped rates are terminated.

The determination of potential stranded costs under Staff's mechanism also would require a functionalized cost of service study that separates out generation costs. After test year adjustments, actual generation costs for the test year (including a fair return) would be used to calculate current, cost-based, unbundled generation rates by customer class. These generation rates would be compared to market-based rates applicable to the test year to calculate the potential stranded cost exposure for that year.

According to Staff, under its proposal, by the end of the capped rate period the earnings tests will have quantified the cumulative net recoveries of stranded costs. In Staff's view, we then would be able to more accurately determine any stranded cost exposure *going forward*, based on the same potential stranded cost calculations, and continued earnings monitoring after the termination of capped rates on the unbundled generation business could provide a calculation of actual stranded costs *or benefits* on an annual basis.

Far from being "consistent with the provisions of the [Restructuring] Act," Staff's proposed mechanism has many of the trappings of a traditional rate case and appears essentially to require that an abbreviated rate case be conducted for each incumbent utility. A rate of return on equity must be set, a test year must be established and a fully functionalized cost of service study must be undertaken. Unbundled rates would be rebundled for purposes of this earnings test analysis. Then, not only would the analysis be conducted through the capped-rate period, it apparently would continue from year-to-year after July 1, 2007, and, in spite of the terms of the Act, provide a measure of stranded benefits.

A number of problems would be encountered in applying this proposed mechanism to Virginia's Electric Cooperatives. To begin, unlike the IOUs, the Cooperatives are not subject to the AIF requirements and do not make such annual reports to the Commission. New reporting requirements would mean new costs to the co-ops. Next, the Cooperatives have never used rate of return or return on equity to measure earnings. The Cooperatives earnings are evaluated in terms of a Times Interest Earned Ratio ("TIER"). TIER would not readily translate to a measure of earnings that would prove useful for Staff's proposed analysis.

This points to the greater, conceptual problems in applying this mechanism to the Cooperatives. There are some fundamental disconnects that would have to overcome, not the least of which is the general lack of vertical integration in the cooperative approach to electric service. As is implicitly recognized in §56-584 of the Restructuring Act, especially considering the Old Dominion Electric Cooperative-member distribution cooperatives, there is a gap in the stranded costs-wires charge cost recovery chain relative to cooperatives. Stranded costs occur at the generation level but wires charge recovery occurs at the distribution levels which, for the cooperatives, are separate and distinct. There are no "bundled earnings" to be tested or evaluated. As was explained in their Functional Separation filings, the Cooperatives have operated on an unbundled, functionally separate basis for some time. The analysis proposed by Staff, as it is stated, simply cannot be applied to the Cooperatives. There is no linkage between any amounts collected above a selected earning level and amounts available to address stranded generation costs. Those amounts, if any, could not simply be made available to mitigate stranded costs. There is no measure of ROE and no comparable method to identify "over-" or "under-collection" of earnings; any such over- or under-collection would not show up in a cooperative's TIER and could not be linked to stranded costs.

4) LTTF requested action #9 reads: "Include in its reports to the LTTF any recommendations for legislative or administrative action that the Commission, the work group, or both, determine to be appropriate in order to address any overrecovery or underrecovery of just and reasonable net stranded costs."

Please discuss whether the definitions and/or methodologies discussed by the work group might require any action as contemplated by Requested Action #9. Discuss what action may be necessary, the timing of that action, and why it is necessary.

This may be the toughest issue on which to comment, largely because it is so dependent on the approach chosen for going forward. The only thing that is clear is that the DVP method could be adopted and put into effect without additional amendment of the statute or any extraordinary administrative action. There are many substantial questions regarding how to apply the other methods and remain consistent with the provisions of the Restructuring Act.

STRANDED COST COMMENTS OF APPALACHIAN POWER COMPANY IN RESPONSE TO THE SCC STAFF'S APRIL 30, 2003 REQUEST FOR COMMENTS

On April 30, 2003, the State Corporation Commission Staff ("Staff") confirmed that the April 29, 2003 meeting of the Stranded Cost Working Group would be the final meeting on the first phase of the Working Group study.[1] The Staff requested written comments on any recommendations for legislative or administrative action to address over-recovery or under-recovery of just and reasonable net stranded costs. In addition, the Staff requested written comments on the several stranded cost monitoring proposals circulated in the Working Group meetings and in writing among the participants. Appalachian Power Company, d/b/a American Electric Power ("Appalachian" or "Company"), provides these comments in response to the Staff's invitation.

1. Legislative Changes to Address Stranded Cost Recovery

The Staff has requested comments from the participants in the Working Group addressing paragraph 9 of the Legislative Transition Task Force ("LTTF") resolution establishing this study. Paragraph 9 provides for the Staff to: "Include in its reports to the LTTF any recommendations for legislative or administrative action that the Commission, the work group, or both, determine to be appropriate in order to address any over-recovery or under-recovery of just and reasonable net stranded costs". The Commission Staff has asked Working Group participants to: "Please discuss whether the definitions and/or methodologies discussed by the work group might require any actions as contemplated by Requested Action #9. Discuss what action may be necessary, the timing of that action, and why it is necessary." Appalachian will address generally legislative issues which would relate to actions that the LTTF should take in response to its statutory

[1] Electronic mail message from Susan Larsen, dated April 30, 2003.

obligation to monitor stranded cost recovery, but which would be independent of any initiative suggesting quantification of stranded costs and their recovery. However, recognizing that legislative comments may be premature under the language of the resolution, Appalachian reserves the right to argue additional legislative issues as they may arise before the LTTF and the General Assembly. [2]

The question of whether the recovery of stranded costs has resulted or is likely to result in over- or under-recovery of such costs should be answered within the context that recovery is proper only to the extent that customer choice develops in accord with the terms of the Virginia Electric Utility Restructuring Act ("Act"). The Act provides that each incumbent electric utility shall only recover its just and reasonable net stranded costs through either capped rates or wires charges. It further provides that the LTTF shall monitor whether recovery has resulted or is likely to result in over- or under-recovery. It does not require quantification of stranded costs or quantification of their recovery.

Stranded costs do not, and will not, exist in the absence of a competitive market (i.e., customers being served at market-based rates). The Act envisions that all customers will be served at competitive market-based generation rates, either by exercising choice or through the default service mechanism, by not later than July 1, 2007. It was on the basis of these provisions that the stranded cost recovery features of the Act were fashioned. Incumbent utilities were allowed to recover, through capped rates and wires charges, costs that will be stranded upon implementation of customer choice and market-based rates. Thus, to the extent that market-based

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[2] Paragraph 9 requests recommendations for legislative and administrative action "to address any overrecovery or underrecovery of just and reasonable net stranded costs." A response to paragraph 9 is premature at this stage of the study. Proposed actions to address "any overrecovery or underrecovery" should await a determination that an under-recovery or over-recovery exists or is likely to exist. In addition, the Company has no recommendations for administrative actions at this point for the same reason. If, on the basis of the Dominion monitoring methodology, the stranded cost recovery provisions were shown to be performing in an unexpected or unacceptable manner, administrative actions by the Commission might be appropriate.

rates are not applied to all customers on or before July 1, 2007, because of unintended disruptions of Virginia's plan, the stranded cost and other provisions of the Act would need to be changed.

At this stage, the LTTF's obligation to determine whether over- or under-recoveries of stranded costs have resulted, or are likely to result, should be satisfied by a timely assessment of whether customer choice and market-based pricing will be implemented as the legislature intended and the Act provides. If the LTTF determines that a competitive market will not develop as planned, and that market-based pricing for all customers on and after July 1, 2007 will not be implemented, it could then take action to identify and propose legislation.

House Bill 2453, approved by the 2003 General Assembly, served to modify the Act to require that incumbent utilities transfer control of their transmission facilities to regional transmission organizations no earlier than July 1, 2004, yet prior to January 1, 2005. The Company suggests that January 1, 2005 represents a reasonable date by which the LTTF should recommend to the legislature alternatives to the requirements of the Act if substantive evidence does not exist which suggests that choice and market-based pricing for all customers as of July 1, 2007 continues to be a viable option.

The Company recommends that the LTTF adopt a resolution providing for an ongoing assessment of whether customer choice and market-based pricing will be implemented as provided by the Act, and thus whether stranded cost recovery by incumbent utilities continues to be appropriate.

2. Monitoring of Stranded Cost Recovery

Working Group participants have proposed two methodologies to monitor stranded cost recoveries, one that comports with the Act and one that does not.[3] Dominion Virginia Power ("Dominion") has presented a methodology that is generally consistent with monitoring the performance of the stranded cost recovery mechanism embodied in the Act. The other methodology ("Staff / Committees model") would result in a return to traditional utility rate regulation analyses, a result that the Company considers beyond the direction in either the Act or the resolution establishing this Working Group study effort issued by the LTTF.

A. The Applicable Provisions of the Act.

The Act contains provisions carefully crafted to give rate certainty to incumbent electric utilities, such as Appalachian, and to their customers during the transition to competition. Section 56-582 limits the rates a utility may charge for generation services through July 1, 2007. The utility is entitled to an opportunity to collect the revenue levels reflected in its regulated rates as effective on July 1, 1999 ("capped rates") and no more.[4] Likewise, the utility's customers are entitled to electric service provided at the capped rates through July 1, 2007.[5]

Other provisions of the Act establish a privilege for customers to leave the generation service of the utility and choose another generation supplier, however. Thus, customers have

[3] The Staff has made two methodology presentations that it asserts are, or can be complimentary, although it also said it prefers the proposal made at the Working Group's meeting on April 7, 2003 to the second proposal presented at the April 29 meeting. In addition, the Virginia Committee For Fair Utility Rates and the Old Dominion Committee For Fair Utility Rates ("Committees"), groups of industrial customers of Dominion Virginia Power and Appalachian respectively, also presented a proposal that combined the two Staff proposals, but added some modifications to the Staff's presentations. All of these proposals are objectionable for the same reasons and are treated as one "methodology" for purposes of these comments.

[4] Capped rates may be adjusted for limited reasons. However, there is nothing in the Act that resembles the broad-based examination of the "cost-of-service regulation" involved in traditional electric utility rate-making.

[5] Capped rates could be terminated before July 1, 2007 only if the Commission found that prices would be limited by effective competition after the termination.

both the opportunity to shop for a lower-price generation supplier and the certainty of capped rates if a lower generation price is not available.

Customer choice does not remove a utility's opportunity to collect the revenue levels reflected in its capped rates. Rather, the Act provides that, if a customer switches generation suppliers, the utility may sell on the market the generation that would otherwise have served the switching customer ("displaced generation"). Any part of the capped revenue not recovered in the market price for displaced generation would be recovered in a wires charge under § 56-583 of the Act. Thus, until July 1, 2007, the Act provides for an opportunity for the utility to collect the revenue levels in its capped rates.

Section 56-584 is a simple declaration that any stranded costs, to the extent they exceed zero value in total, "shall be recoverable" through capped rates or wires charges. It creates no process other than the provisions of §§ 56-582 and 56-583 for stranded cost recovery nor any process to adjust capped rates or wires charges. In fact, it states the opposite. The incumbent's only sources of stranded cost recovery are capped rates and wires charges through the transition period. Section 56-595 C (iii) provides only that the LTTF, with the assistance of the Commission and others, shall monitor the stranded cost recovery contemplated in § 56-584. It says nothing about calculating total stranded costs, and such a calculation is not necessary to the process set forth in the Act.

Section 56-595 C (iii) cannot be read to require or permit a methodology to monitor whether the capped rate revenue level is inadequate or excessive. There is no authority for the monitoring methodology to compare capped rate revenue levels to some other calculated revenue level based on a cost-of-service analysis as would be done in a traditional utility rate case. There is no mention of the "calculation" or "projection" of anything in § 56-595 C (iii), let alone the calculation or projection of total stranded costs.[6] The monitoring that should be required is to determine if the capped rate and wires charges mechanism for switching customers is performing as contemplated to keep the incumbent utility indifferent as to whether a customer switches generation suppliers before July 1, 2007.[7]

The first numbered paragraph of the LTTF resolution establishing this study anticipates that the recommendations under consideration at this stage will be "consistent with the provisions of the Act". As will be discussed herein, only Dominion has proposed a methodology arguably consistent with the Act. The other methodological presentations to the Working Group clearly go beyond the current provisions of the law.

B. Dominion Virginia Power Methodology

In order to implement the wires charges mechanism in § 56-583, the Commission must project market prices for generation sales. This is an express requirement in the wires charges provisions of § 56-583. Compared to actual experience, projected market prices that are too low could increase wires charges to a level that would over-recover revenues that are intended to cover stranded costs. Projections that are too high could decrease wires charges to a level that would under-recover revenues that are intended to cover stranded costs. Accordingly, Dominion proposed a method that would, in part, monitor the accuracy of the Commission's projections of market prices as compared to actual market prices experienced after the projection. Such a

[6] The Staff and Committees proceed from an assumption that the only means to monitor stranded cost recovery is to calculate total stranded costs. There is nothing in the Act that suggests any basis for such an assumption, and its acceptance would require substantial changes to the Act, including changes to the sections governing capped rates and wires charges. The Commission has properly determined that no calculation of total stranded costs is necessary under the Act. Application of Northern Virginia Elec. Coop., for review of tariffs and terms and conditions of service, Case No. PUE-2002-00086, Final Order at 2, n. 3 (June 18, 2002).

[7] The Commission has correctly determined that the Act is intended to keep the utility indifferent in this regard under the wires charges provision of the Act. Commonwealth of Virginia, at the relation of the State Corporation Commission, Ex Parte: In the matter of considering requirements relating to wires charges pursuant to the Virginia Electric Utility Restructuring Act, Case No. PUE-2001-00306, Final Order, at 25 (November 19, 2001).

process would monitor the adequacy of the wires charge process and would be clearly within the current provisions of the Act. To this extent at least, the Dominion methodology appears to be consistent with the Act, and Appalachian has no further comment on the Dominion model at this point.

C. **Staff / Committees Model**

Neither the two proposals of the Staff nor the presentation of the Committees on April 29 are consistent with the Act. All of them suffer from the same overriding flaw. Rather than monitor the performance of the capped rate and wires charges provisions of the Act, each of these methodologies appears directed at re-evaluation of the reasonableness of capped rate revenue levels. As stated previously, nothing in the Act even suggests that the stranded cost monitoring process should become a broad re-evaluation of capped rate revenue levels.

The first proposal of the Staff was described orally at the Working Group session on April 7, 2003. Using graphs drawn on a chalkboard to illustrate the concepts, Staff representatives made clear that the revenue level produced by capped rates could vary under the methodology based on an evaluation of costs and a fair rate of return – the traditional utility rate-making standard. On April 29, both the Staff and the Committees made similar assertions. The Staff wrote: "Recovery of stranded costs occurs throughout the capped rate period to the extent actual earnings exceed costs plus a fair return. These recoveries can be calculated and monitored using the earnings test mechanism." The Committees asserted in part that stranded costs are recovered in capped rates "to the extent that capped rates exceed actual and likely costs including a fair return … ."

The revenue levels produced by capped rates were set by the Commission and adopted in the Act, and they are presumed to be just and reasonable. For capped rates to produce revenues in excess of costs plus a fair rate of return as the Staff / Committees model suggests, a rate case type of analysis would be required to second-guess the capped rates already established by Commission order and by statute. According to the Staff's presentations in the Working Group, factors such as an incumbent's authorized rate of return on equity capital might be subject to change in such an analysis of capped rates. The process would simply devolve into time consuming and expensive analyses that would be the equivalent of annual rate cases.

The goal of re-evaluation of capped rates is unclear. Expressly, it is to determine the amount of capped rate revenue that is available to cover stranded costs. However, unless capped rates or wires charges would be adjusted on the basis of the re-evaluations, there would be no effect on customers, positive or negative. And, suppose the re-evaluation showed that capped rates were too low to cover costs plus a fair return. Would they be increased to meet the cost plus a fair return standard? Would they be increased further to provide some excess over costs plus a fair return in order to cover all or a portion of stranded costs made recoverable by § 56-584?

The General Assembly provided in the current provisions of the Act only for increases or decreases in capped rates to a limited extent currently stated in the law. Section 56-595 C (iii) of the Act should not be interpreted to suggest that the General Assembly also adopted, silently through general language requiring the monitoring of stranded cost recovery, a process that permits unlimited increases or decreases in capped rates. The only objective reading of the current legislation as a whole is to conclude that the General Assembly intended neither to increase nor decrease capped rates prior to July 1, 2007 except in the limited manner expressly stated in the Act. For this reason, the methodology suggested by the Staff and the Committees is either inconsistent with the capped rate provisions of the Act because it would contemplate changing capped rates for reasons not set forth in the Act, or it would require time-consuming and expensive rate analyses and proceedings, with little or no impact on customers and raising utilities' costs without tangible benefit to either customers or companies.

In commenting on the Staff's April 7 presentation to the Working Group meeting, Appalachian said: "The Staff model would require fundamental changes in the Act and would be little different than traditional utility rate regulation." The subsequent presentations of the Staff and the Committees have confirmed this comment. As described previously, the methodology proposed by Staff and Committees is inconsistent with the capped rate and wires charges provisions of the Act. However, the Staff / Committees model is inconsistent with other provisions of the Act as well.

For example, the Committees' presentation of April 29 states: "As is true of any administrative method of determining stranded costs, the above approach [the Staff / Committees methodology] involves estimates based on long-term revenue and cost projections." The methodology proposed by the Staff and the Committees expressly requires an "administrative determination" of stranded costs. The Act seeks to avoid administrative determinations of stranded cost.

The Staff, in its presentation on April 29, said: "A bundled earnings test should be used until such time as bundled, capped rates are terminated. It is proper to use a bundled earnings test since all earnings produced under bundled, capped rates that are in excess of actual costs plus a fair return can be used to mitigate stranded cost exposure." The suggestion that cost reductions in distribution and transmission functions should be used to offset stranded generation costs is inconsistent with the provisions of § 56-590 prohibiting one utility function from subsidizing another. In Appalachian's functional separation case, the Commission has made clear that it will not permit such subsidies.[8] There is nothing in the Act that suggests that § 56-595 C (iii) reverses the anti-subsidy language of § 56-590.

The Staff should report to the LTTF that the methodology proposed by it and the Committees would be inconsistent with the current provisions of the Act. As described previously, the Staff / Committees proposals would require changes in fundamental precepts of the Act, such as limited adjustments to capped rates and functional separation of incumbent utilities without subsidies among the separated functions. Specific amendments to the Act should be set forth in the Staff's report to give Working Group participants an adequate opportunity to address them before the LTTF and the General Assembly.

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[8] Application of Appalachian Power Company d/b/a American Electric Power-Virginia, for approval of functional separation plan, Case No. PUE-2001-00011, Order On Functional Separation, at 11-13 (December 18, 2001).

State Corporation Commission
of Virginia

In the matter of developing	*	
consensus recommendations	*	Case No. PUE- 2003-00062
on stranded costs	*	

Comments by The Potomac Edison Company dba Allegheny Power

1) **LTTF requested action #9 reads: "Include in its reports to the LTTF any recommendations for legislative or administrative action that the Commission, the work group, or both determine to be appropriate in order to address any overrecovery or underrecovery of just and reasonable costs."**

Response:

As stated in prior submitted documents and verbally at the Work Group's meetings AP does not believe it has a stranded cost recovery issue. AP is different than the other utilities because as part of a Memorandum of Understanding (MOU) in the functional separation plan in Case No. PUE-2000-00280, AP waived its right to assess a wires charge, increased its fuel factor and rolled its fuel factor into base rates (thereby accepting greater risk with respect to fuel prices), and agreed to not make a claim for any additional stranded cost recovery in 2007. AP believes these factors defined its total restructuring related risk exposure during the transition period.

If AP now faces a double jeopardy of sorts, that is, if it is to be required to quantify stranded costs, to consider excess earnings as a recovery of stranded costs and to identify actions that either mitigated or increased stranded costs during the transition period then it will experience far more risk than it agreed to under the terms of the MOU and also relative to the other utilities.

Inherent in the MOU was the understanding that whatever stranded costs exist for AP, would be recovered through capped rates. To the extent that customers shop, AP assumes the risk and loses revenue, as the Company has foregone assessing the wires charge. Absolutely essential to this agreement and acceptance of risk was the understanding that capped rate levels would be maintained through the transition period, as legislatively mandated by Section 56-582.

The presumption in the Restructuring Act is that a utility's capped rates in effect on January 1, 2001 provide a just and reasonable level of revenues. To the extent that customers shop during the transition period, utilities are entitled to recover from customers the revenues lost as a result of shopping via a wires charge. This lost revenue approach functions to identify and quantify stranded costs. Analyzing stranded cost recovery through capped rates on the other hand requires a rate-case-like cost of service analysis at least annually to determine some fair level of rates and then a comparison of those levels with the revenues actually produced by the capped rates. The Restructuring Act makes no provision for such an analysis and appears instead to call for stranded cost recovery of lost revenues through a wires charge.

In addition, AP views the Asset Valuation Model as significantly deviating from the lost revenue approach adopted by the Restructuring Act. This model attempts to travel down the road of quantification that was, for good reason, abandoned by the legislature, the Virginia SCC Staff, and other stakeholders in drafting the Restructuring Act. AP does not advocate the Asset Valuation Model be recommended to the LTTF, but in the event it is, AP perceives execution of this model would require an amendment to the Restructuring Act, as the statute as currently drafted does not provide for nor does it require such quantification.

2) Comments regarding the proposal put forth by Ed Petrini.

AP's understanding of the Committees proposal is that it is an effort to summarize the Staff models and to also reflect the Committees acceptance of the methodology employed by the Staff models. See AP's comments on the Staff proposal below.

3) Comments on Staff proposal.

The Staff Accounting Perspective proposal defines the <u>recovery of stranded costs</u> as the amounts collected through earnings in excess of its "revenue requirement". Presumably, the assumption is that utilities have lower actual generation and T&D costs than the costs collected through its current capped rates as a result of its stranded cost mitigation efforts and/or reductions in its T&D costs. Such over collection of costs may result in earnings above the revenue requirement of the utility.

Unlike the Dominion Virginia Power (DVP) approach, which collects revenues through a wires charge from shopping customers, this methodology has no direct correlation to the existence of a competitive market with shopping customers. For example, a utility could have earnings above a revenue requirement level due to an unreasonably low allowed ROE, consistently colder/warmer than normal weather, technological/operational improvements resulting in more efficient processes, new customer growth, and realizing gains from earlier investments to name a few potential sources of additional revenues. Under the proposed approach any excess benefits from the cumulative impact of these types of items could be mislabeled as stranded cost recovery amounts, even without one customer shopping.

The excess earnings calculation of the recovery of stranded costs may also infer to consumers that T&D costs are stranded since part of the excess revenues may come from T&D base rates. Stranded costs are generation related and are typically collected through a specific charge, such as the Wires charge, or in Pennsylvania, the Competitive Transition Charge (CTC). It may be confusing for consumers to understand that stranded costs in Virginia may be recovered (via excess earnings) through the Generation and T&D rates as well as a Wires charge.

The proposed administrative methodology to quantify stranded costs requires many assumptions and estimates that will quite likely differ at any point in time. To perform a one time Asset Valuation Model (NPV approach) would be time consuming, expensive and highly conducive to debate given the number of variables and assumptions. The result of a one-time estimate of stranded generation costs would also very likely be higher or lower than any following estimates due to changing market conditions. AP's experience has been that administratively determined stranded cost models were greatly debated and the results considered questionable due to the methodology employed.

For these reasons, AP cannot support the methodologies proposed by the Staff. DVP's methodology, which utilizes many of the same processes currently in place, properly correlates stranded cost recovery with customers that shop and ends all stranded cost recovery in 2007 is a superior model for resolving the issue of stranded costs quantification and recovery.

Staff also proposes that <u>potential stranded costs</u> be measured each year of the transition period. This would require a cost of service study that incorporates the earnings test adjustments applicable to the test period. Actual generation costs for the period would be used to calculate current cost based unbundled generation rates by customer class. These actual generation rates would be compared to the market-based rates applicable to the test year to calculate the potential stranded cost exposure for the year.

Staff's comments that the process described above will provide insight into the success of mitigation efforts and the likelihood of whether an over or underrecovery of stranded costs will occur.

AP feels that the above methodology may be an exercise that provides information that has little practical value. Utilities have every reason to mitigate generation costs between now and the end of the transition period. If market prices are low after the transition period, utilities may be better able to compete if they have successfully mitigated costs to at or near or below market levels. If market prices are high, a utility may enjoy the benefits of a lower cost product relative to the market price through its successful cost mitigation efforts.

Measuring the success of mitigation is also a difficult task. A successful mitigation of costs may be a small percentage reduction in actual rates compared to the capped generation rate for a well run low cost utility but a much higher percentage for utility that has mitigable costs in its capped rates. The most meaningful measurement of the success of mitigation efforts will occur when a competitive market exists.

AP is unclear as to how identifying 100% of the potential stranded costs during the transition period is a useful measurement to indicate whether or not an over or underrecovery of stranded costs will occur.. AP feels that a better indicator of the potential stranded cost exposure is reflected by how customers have responded since competition began in Virginia. If the Commission requires the use of the recovery of stranded cost calculation, the better estimate of an over or underrecovery of potential stranded costs may be to compare any recovery of stranded cost amounts to the amount collected through the Wires charge each year. If you have $2 million collected in Wires charges for the year it would be prudent of the utility to also reduce operating costs by a similar amount in order to remain competitive when actual market conditions exist. Finally, the Staff model suggests applying recovered stranded costs during the transition period to any stranded costs exposure going forward. AP believes that all stranded cost issues should be resolved at the end of the transition period in order to have a fully competitive market.

4) Comments on the clarifications of Dominion's proposal.

AP does not disagree with the clarifications related to Dominion's proposal. AP continues to support Dominion's proposal.

Virginia Independent Power Producers, Inc.

August Wallmeyer, Executive Director
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May 8, 2003

Ms. Susan Larsen
Division of Public Accounting
State Corporation Commission
P.O. Box 1197
Richmond, VA 23218

Via Email

Dear Ms. Larsen,

Virginia Independent Power Producers, Inc. (VIPP) offers comments on the following: (1) Staff's April 28, 2003 "Accounting Perspective" Proposal; (2) the proposed VCFUR approach distributed at the April 29, 2003 Working Group Meeting; and (3) the clarified Virginia Power approach distributed on April 24, 2003. In addition, VIPP's recommendations for legislative or administrative action, pursuant to paragraph 9 of the January 27, 2003 Resolution of the Legislative Transition Task Force, are provided.

Very truly yours,

/s/

August Wallmeyer

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COMMENTS OF

VIRGINIA INDEPENDENT POWER PRODUCERS, INC.

TO THE STRANDED COSTS WORKING GROUP

MAY 8, 2003

Introduction

In these comments, Virginia Independent Power Producers, Inc. ("VIPP") addresses: (1) Staff's April 28, 2003 "Accounting Perspective" Proposal; (2) the proposed VCFUR approach distributed at the April 29, 2003 Working Group Meeting; (3) the clarified Virginia Power approach distributed on April 24, 2003; and (4) VIPP's recommendations for legislative or administrative action, pursuant to paragraph 9 of the January 27, 2003 Resolution of the Legislative Transition Task Force (the "LTTF Resolution").

VIPP asserts that the Staff and VCFUR proposals are inconsistent with the basic approach to stranded costs recovery adopted by the Legislature in the Virginia Electric Utility Restructuring Act (the "Act") and, if adopted, would add an unnecessary element of complexity to the Work Group's effort to be responsive to the LTTF. *See* ACT, § 56-595.C(iii).

The appropriate approach to monitoring stranded cost recovery is to compare (i) the cost-based generation component of capped rates to (ii) the generation-related revenues (including wires charge revenues) that would have been received based on competitive market prices throughout the transition period (on the assumption that all customers of the incumbent utility either switched to another supplier or received default service from the incumbent utility at market-based rates).[1] This determination of potential stranded costs would be a useful indicator of whether under- or over-recoveries may occur in the future. Moreover, since actual stranded costs cannot be determined until after 2007, this is the only reasonable methodology to present to the LTTF.

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1 If (i) is greater than (ii) there is an over-recovery; and *vice versa*.

Staff's "Accounting Perspective" Proposal

- Staff's proposed method would "indicate annual recoveries of stranded costs throughout the transition period [using] an accounting approach based on an earnings test mechanism." According to comments made at the April 22 Work Group meeting, Staff would perform the calculation of "excess" earnings on an annual basis between now and 2007 and would include in the calculation excess earnings from the transmission and distribution components of embedded cost rates.

- Staff's proposal to use "excess earnings" to measure stranded cost recoveries is flatly inconsistent with the LTTF Resolution and the Act. Paragraph 1 of the LTTF Resolution makes it clear that the definitions, methodology and calculations to be made under Paragraphs 2 and 3 of the Resolution must be "consistent with the Act." The Act is bereft of even an indirect reference to an earnings test as the basis for determining stranded cost recoveries. Said differently, there is absolutely no linkage whatever, expressed or implied, in the Act between stranded cost recovery and a utility's earnings. Staff's proposal to forge such a linkage would establish a far-reaching new policy for the Commonwealth. In so doing, Staff would be usurping territory that is the exclusive province of the General Assembly.

- The Staff Proposal would create a scheme of incentives directly at odds with the intent of the General Assembly. In formulating capped rates, the General Assembly intended to provide incumbent utilities with an incentive to reduce future stranded costs by engaging in cost cutting and stranded cost mitigation. Perversely, the Staff Proposal would now penalize utilities for doing exactly that. For example, under the Staff's "earnings test" proposal, an incumbent utility that cut $10 million in expenses would now be found to have $10 million more in "excess earnings" and would be penalized for cutting its costs.

- While the Staff Proposal would use the Annual Informational Filing ("AIF") as its starting point for the determination of "excess earnings," it is certain that AIFs would not be acceptable to all parties as properly representing the incumbent utility's revenue requirement.

Experience shows that the AIF is only the first step in a series of discussions, akin to a rate case, about the extent to which book earnings should be adjusted to incorporate "rate making" adjustments. In addition to requiring resolution of these issues, the Staff Proposal would require reaching consensus as to an appropriate rate of return for each year of the transition period. In effect, the Staff Proposal would require the incumbent utility and the Staff to engage in complex annual rate cases—hardly the result anticipated by the General Assembly when it **deregulated** generation.

The Proposed VCFUR Approach

- Like Staff's Proposal, the proposed VCFUR method would calculate stranded cost recoveries during the transition period. In so doing, the VCFUR method suffers from the same infirmities as the Staff Proposal. Thus, the VCFUR method would also be contrary to the Act and would improperly reinstitute annual rate cases to determine so-called excess earnings.

- The VCFUR proposal, however, would go far beyond the Staff Proposal and would repeat the mistakes of other regulatory jurisdictions by attempting to project both generation market prices and the embedded cost-based prices for generation for every year of the approximately thirty-year time horizon constituting the remaining life of current generation assets.

- Although VCFUR's written comments attempt to convey the impression that the basic elements of the VCFUR proposal are required by the Act, this is not the case. Section 56-595.C(iii) provides that members of the LTTF shall monitor whether the recovery of stranded costs, as provided in § 56-584, has resulted or is likely to result in the over-recovery or under-recovery of just and reasonable net stranded costs. VCFUR's written comments attempt to stretch and contort this language into a precise mathematical formula, stating that the "LTTF *must* determine and compare two amounts: first, the amount that has been, or will be, available for recovery of just and reasonable net stranded costs, and second, the amount of just and reasonable net stranded costs." VIPP disagrees. VCFUR's interpretation is simply not correct or required.

- First, although VCFUR would pretend otherwise,[2] nowhere does the Act even mention the term "net" revenues and nowhere does it contemplate the rate case-type calculation that VCFUR says is absolutely "required." Second, contrary to VCFUR's contention, the incredibly complex projection of future stranded costs that constitutes the second component of their proposal is not required either. VIPP believes that Section 56-595.C(iii)'s mandate to the LTTF to report on whether stranded costs are likely to be over- or under-recovered could and should be satisfied by using a far simpler method, such as the one proposed by Virginia Power to calculate potential stranded costs during the transition period.

- As thoroughly discussed in VIPP's initial comments, the type of market price and embedded cost projections that VCFUR recommends would be unreliable and subjective in the extreme.

The Clarified Virginia Power Approach

- The Virginia Power approach would require a utility to calculate and report to the LTTF, for each year of the transition period, (1) whether there was an over- or under-recovery of stranded costs collected through the wires charges from switching customers and, if so, the amount thereof; (2) the company's actual "above-market" or "potential" stranded cost exposure under capped rates; (3) the amounts it has expended from funds available under capped rates to mitigate potential stranded costs; and (4) additional expenditures that increase such costs during the transition period. Referring to items (2) and (3) of the Virginia Power approach, one can devise a fairly uncomplicated method of monitoring stranded costs.

- VIPP believes that this refreshingly down-to-earth approach would be acceptable under § 56-595.C(iii). First, unlike the Staff and VCFUR methods, the Virginia Power approach is consistent with the Act. Second, the Virginia Power method is eminently practical and would fulfill the requirements of § 56-595.C(iii) because it would provide a basis for an analysis of whether stranded costs are likely to be over- or under-recovered in the future.

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[2] *See* Fourth Bullet, April 22 VCFUR handout. Following a discussion of *net stranded costs* as set forth in § 56-584 in Bullet Three, VCFUR argues in Bullet Four that it necessarily follows ("Thus") that the amount that will be available for recovery of net stranded costs is the "*net revenue* collected from wires charges and capped rates."

- Finally, the disclosure of amounts expended for stranded cost mitigation and additional expenditures during the transition period would be valuable. One of the Act's central goals is to ensure that Virginia's utilities would be ready to meet the challenge of retail competition. An evaluation of stranded cost mitigation and additional potential stranded cost exposure would enable the LTTF to consider whether this goal is being met.

VIPP's Recommendations for Appropriate Legislative or Administrative Action

- The stranded cost provisions of the Act were carefully crafted to achieve a balance among competing interests. In that balance lies Virginia's unique solution to the stranded cost issue. The General Assembly recognized the need for rate structures that would create an opportunity for the Commonwealth's incumbent utilities to recover just and reasonable net stranded costs and at the same time would ensure their financial stability as they approached the era of retail competition. The key concept underlying the Act's stranded cost provisions is that stranded costs are not be administratively determined and recovered on a dollar-for-dollar basis through discrete rate mechanisms, as in other jurisdictions. Unfortunately, and in direct conflict with the Act, the Staff and VCFUR monitoring proposals veer dangerously in this direction.

- VIPP is extremely concerned that the Staff and VCFUR proposals, if adopted by the Work Group and the LTTF, would put the Commonwealth back on a path leading to annual rate cases, intrusive re-regulation of utilities, and a hurried retreat from the Act's restructuring goals. This would be extremely unfortunate. The implementation of the Act's well-considered framework for competition is in its early stages, and competition has just begun.

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STRANDED COSTS WORK GROUP
SCC Case No. PUE-2003-00062

DIVISION OF CONSUMER COUNSEL
OFFICE OF THE ATTORNEY GENERAL
SUPPLEMENTAL COMMENTS

As requested by the Commission Staff following the stranded costs work group meeting on April 29, 2003, the Division of Consumer Counsel, Office of the Attorney General ("Consumer Counsel") submits these supplemental comments in response to the following questions posed by the Staff regarding additional issues raised at the April 29 meeting:

- **Comments regarding the proposal put forth by VCFUR/ODCFUR.**

The proposal put forth by Mr. Petrini for the Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates essentially restates the SCC Staff proposal for calculating just and reasonable net stranded costs, which the Staff has termed an "asset valuation" methodology. Consumer Counsel's views on this general approach are reflected in our comments of April 18, 2003.

- **Comments on the Staff proposal discussed at the April 29 meeting.**

Consumer Counsel understands the SCC Staff's "Accounting Perspective" proposal could be used either in conjunction with its proposed asset valuation stranded costs calculation method or in isolation as a free-standing method. It would employ an "earnings test" mechanism that could serve to show the extent to which stranded costs have been recovered through capped rates. Because the Restructuring Act provides that stranded costs are recovered through both capped rates and wires charges, an approach that considers recoveries through capped rates could be beneficial inasmuch as there is currently little customer switching and thus limited stranded costs recovery via wires charges. The Staff states in its proposal that: "Continued earnings monitoring after the termination of capped rates on the unbundled generation business could provide a calculation of actual stranded costs or benefits on an annual basis." Consumer Counsel is not entirely clear to what end such continued monitoring would serve, but we note that the Restructuring Act limits incumbent utilities' opportunity to recover stranded cost to the capped period, expiring July 1, 2007.

- **Comments on the clarifications of Dominion Virginia Power's proposal.**

Consumer Counsel believes that the clarifications by Dominion Virginia Power to its proposal are helpful. As "clarifications," however, they do not alter the fundamental aspects of the company's proposal. Consumer Counsel's views on the company's proposed approach are reflected in our comments of April 18, 2003.

DIVISION OF CONSUMER COUNSEL
OFFICE OF THE ATTORNEY GENERAL

May 8, 2003

Stranded Cost Work Group

Virginia Citizens Consumer Council Comments

May 13, 2003

Answers to the questions posed by the State Corporation Commission Staff:

1) LTTF Action # 9

This item has not become any easier to address as the years have gone by since parties involved in energy restructuring in Virginia first broached it. It is clear that although the utilities insist that they are owed the money to pay for any possible stranded costs, they are not interested in actually releasing a dollar value for the stranded costs they anticipate. Unless this is done, it will not be possible to appropriately "address any overrecovery or underrecovery of just and reasonable net stranded costs." The Stranded Costs Work Group has spent hours discussing the issue – but mostly discussing everything but the central issue of how to fairly calculate the stranded cost. It is evident that should utilities be forced to calculate them, exorbitant costs are likely to be claimed and huge sums of money and time will be required of all parties to sort out fair costs. The issue is critical for IOU's since the cooperatives are owned by their users and any over-collected fees will benefit those who paid them. Also, based on experience in other states, the cooperatives serve consumers that few, if any, other competitors seek to serve.

Since stranded cost is something that will actually only occur if utilities are unable to sell as much electricity as they have sold in the past at a price that is at least as high as they have received in the past, and since market prices continue to be significantly above those charged in Virginia, maybe it is time to look at this issue in a different way. Given recent and distant past energy prices in Virginia and beyond, it seems reasonable to anticipate that energy prices in the competitive market are not likely to decline to or below the level currently paid in Virginia. This is especially true if Virginia's investor owned utilities win their bids to join PJM. Thus, maybe the question should be: Is it currently reasonable to assume that Virginia utilities will have any stranded costs when the competitive market takes over?

Elected officials need to decide whether it is worth spending the resources to force calculation of stranded costs. They need to determine if the citizens of Virginia who have paid their utilities a fair profit for energy through the years and paid for the infrastructure that currently exists, are owed a fair determination of stranded costs. It is clear that the parties involved in the Stranded Cost Work Group are not going to successfully negotiate resolution of this issue. State Corporation Commission Staff cannot either make this decision or calculate the cost on their own. They do not have the necessary information. Further, since some parties miss no opportunity to criticize and disparage every action or lack of action by the SCC, the results are not likely to be accepted. Legislators need to make this decision before further work is attempted by the Stranded Cost Work Group. If cost is an issue, it would be far more valuable for Dominion, for example, to shift the funding it has proposed to spend on its pilots to assuring that stranded cost is appropriately calculated and proven so we can assure that the overall process if fair to all parties. It is far more important to resolve this issue than to attempt to create a proxy for default service at a point when the national retail competitive market is essentially not functioning anywhere.

2) Comments regarding the proposal put forth by Ed Petrini.
The proposal put forth by Ed Petrini appears to be the most reasonable strategy discussed by the Work Group. Using an existing source of information provided by all utilities to the SCC seems appropriate. This procedure seems to possibly have fewer items for the parties to contest but will still require cooperation of all parties.

3) Comments on the Staff proposal
No new comments. This could work. However, the roadblock seems to be the need for a number of assumptions that the some will contest and thus attempt to undermine the strategy.

4) Comments on the clarifications of Dominion's proposal
This proposal still allows companies to collect the maximum in stranded costs with no requirement to prove that any exist. It assumes income at the highest possible level. It is unfair to both consumers and potential competitive providers.

Irene E. Leech, Ph.D.
President

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May 8, 2003

DELIVERED ELECTRONICALLY

Susan Larsen, Deputy Director
Division of Public Utility Accounting
State Corporation Commission
1300 East Main Street
Richmond, VA 23219

Re: ***Commonwealth of Virginia, ex.rel. State Corporation Commission***
In the matter of developing consensus recommendations on stranded costs
Case No. PUE-2003-00062

Dear Susan:

To assist in achieving consensus, the Commission Staff has encouraged parties to discuss among themselves possible methods for calculating "just and reasonable net stranded costs" and their recovery. During the work group meeting on April 21, 2003, representatives of customers and competitors seemed to be coalescing, broadly speaking, around a single concept. Further discussion has allowed them to refine it further. Accordingly, Attachment I is submitted on behalf of the following interested parties: Virginia Committee for Fair Utility Rates, Old Dominion Committee for Fair Utility Rates (collectively, "the Committees"), TXI/Chaparral (Virginia) Inc., VML/VACo APCo Steering Committee, Virginia Citizens Consumer Council, Washington Gas Energy Services, Strategic Energy, Constellation New Energy, and Pepco Energy Services.

Attachment I reflects, with a minor change, the paper distributed by the Committees' counsel at the work group meeting on April 28, as well as key elements in the Committees' written comments of April 16.[1] The approach contained in Attachment I is reasonable and consistent with the Restructuring Act. You have referred to the approach to the calculation of just and reasonable net stranded costs included therein as the "Asset Valuation Methodology," and we will do so here.

The Commission Staff also has requested comments on the following issues: (i) Virginia Power's "clarifications" to its prior proposal; (ii) the Commission Staff's accounting proposal,

[1] In response to suggestions at the meeting on April 29, Attachment I reflects use of the term "revenue" in lieu of "net revenues" in lines one and three of the fourth bullet of the paper distributed at that meeting.

discussed at the April 29 meeting;[2] and (iii) requested action number 9 of the Legislative Transition Task Force ("LTTF"), relating to appropriate legislative or administrative actions to address any overrecovery or underrecovery of just and reasonable net stranded costs. Regarding each of these issues, the Committees offer the following comments.

I. Virginia Power's Clarifications to its Prior Proposal

As Attachment I indicates, Section 56-595.C (iii) of the Act requires the LTTF to monitor the over-recovery or under-recovery of just and reasonable net stranded costs,[3] and to do so, the LTTF must determine and compare two things: first, the amount that has been, or will be, available for recovery of just and reasonable net stranded costs, and, second, the amount of just and reasonable net stranded costs.

The Act, in Section 56-584, provides that two sources of revenue are available for recovery of just and reasonable net stranded costs -- capped rates and wires charges. Thus, the answer to the first side of the inquiry is straightforward: the amount that has been, or will be, available for recovery of such costs is the revenue collected from wires charges and capped rates in excess of the revenue needed by the utility to recover its costs of providing service (*i.e.*, the utility's revenues in excess of its revenue requirement).

Virginia Power's proposal, as clarified, still does not represent a "methodology for calculating 'just and reasonable net stranded costs,'" and it still does not calculate such costs. Nor does it, as clarified, calculate the amount available for their recovery. While it states that it would require an "annual" calculation of the "over-recovery" or "under-recovery" of "stranded costs *collected through wires charges*," its explanation of that "determination," as "clarified," reveals that it still does not calculate an "under-recovery or over-recovery" of stranded costs collected through wires charges.[4] Instead, Virginia Power merely proposes to calculate the difference between revenue collected from customers via wires charges and revenue that would have resulted if wires charges had been based on "actual" market prices experienced during the year. Thus, Virginia Power proposes to calculate the amount of revenue collected from wires charges, but not the over- or under-recovery of stranded costs recovered through wires charges. Virginia Power, moreover, proposes to ignore entirely any inquiry into the "under-recovery or over-recovery" of stranded costs through capped rates.

Thus, Virginia Power's proposal, as clarified, still fails to address the two sides of the inquiry required of the LTTF pursuant to Section 56-595.C (iii) of the Act as well as the directive

[2] Staff's proposal is called "Stranded Costs, an Accounting Perspective" (hereafter, "Accounting Proposal").
[3] Section 56-595.C (iii) of the Act provides that the members of the LTTF "shall: ... monitor ... whether the recovery of stranded costs, as provided in § 56-584, has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs."
[4] Virginia Power's proposal, showing, in a black-line version, its recent "clarifications," is attached as Attachment II.

in the LTTF's Resolution, which parallels that Section of the Restructuring Act.[5] Virginia Power's proposal would calculate neither the amount of "just and reasonable net stranded costs" nor their over- or under-recovery through revenues from wires charges *and capped rates*.

Virginia Power's proposal, as clarified, still mentions expenses for "mitigating" potential stranded costs, and it further mentions "additional expenditures that negatively impact (increase) such costs during the transition period." A utility would calculate and report such expenses annually to the LTTF. Such calculations, however, do not provide a method to calculate just and reasonable net stranded costs or the means for their recovery. Thus, Virginia Power's proposal, as "clarified," continues to suffer from the same essential defects as those identified in the Committees' comments of April 16.

Virginia Power's "clarification" also recommends a calculation not included in its prior proposal – namely, an annual calculation of "the company's 'potential' stranded costs exposure under capped rates." Under this proposal, Virginia Power would compare "actual market prices experienced during the year to its unbundled generation rate" and, it states, determine the "potential revenue impact had all sales been made at those market prices rather than at capped generation rates." This calculation, Virginia Power asserts, would yield "potential stranded costs exposure during each year of the transition period." The Commission Staff has offered a similar proposal as part of its Accounting Proposal.[6]

The proposed calculation of annual stranded cost "exposure" is not a calculation of "stranded costs" or "just and reasonable net stranded costs," nor is it a calculation of the recovery of such costs through capped rates and wires charges. Thus, Virginia Power's proposal to calculate annual "exposure" to stranded costs may confuse, and potentially mislead, the inquiry required of the LTTF pursuant to Section 56-595 C (iii) of the Restructuring Act and the LTTF's Resolution. The useful lives of Virginia Power's generation assets are not one year in length. Nor, typically, are the terms of its purchased power agreements. On the contrary, the useful lives of such assets, and the terms of such agreements, typically are much longer than one year. Nor is it likely that all of Virginia Power's customers would take generation service from an alternative supplier at short-term energy prices for one year. The calculation, in short, misses the point. Requiring such an annual calculation, moreover, may lead to misperceptions about the extent to which a utility likely will over- or under-recover its just and reasonable net stranded costs. The proposal should not be adopted.

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[5] The LTTF's Resolution, in Requested Actions, number 2(b), requires the work group to present consensus recommendations regarding a "methodology to be applied in calculating each incumbent electric utility's just and reasonable net stranded costs, amounts recovered, or to be recovered, to offset such costs, and whether such recovery has resulted in or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs…"

[6] See, Staff's Accounting Proposal, page 1, the third bullet.

II. Staff's Accounting Proposal

Staff's Accounting Proposal, a copy of which is attached (Attachment III), would include a calculation of annual recoveries of stranded costs during the capped rate period based on the extent to which actual earnings exceed costs plus a fair return. The calculation of actual earnings would use an earnings test mechanism. Staff states that it would be "necessary to agree upon an appropriate fair rate of return to use as a benchmark ROE from which to measure earnings available for stranded cost recovery."

As indicated in Attachment I, the earnings test that would be applied by the Staff in its review of utilities' annual informational filings would be an acceptable means of measuring the revenue available for recovery of stranded costs.

Staff also proposes that "potential stranded cost exposure" also be calculated. Staff defines "potential stranded cost exposure" as "the annual stranded cost exposure during the capped rate period, assuming all customers are paying market rates for generation service." Thus, as indicated above, Staff proposes a calculation of "potential stranded cost exposure" that is similar to that proposed by Virginia Power, and Staff's proposal suffers from the same deficiencies as those identified above in connection with Virginia Power's proposal.

Staff proposes that during the capped rate period comparisons can be made between stranded cost recoveries and potential stranded cost exposure. While information regarding revenue available for recovery of stranded cost is essential to determining over- or under-recovery of such costs, it is not clear what, if any, additional "insight" into the likelihood of over- or under-recovery of stranded costs is gained by annual calculation of such "exposure."

III. Recommendations for Legislative or Administrative Action

The LTTF's Resolution requests that the Commission include in its report to the LTTF "any recommendation for legislative or administrative action that the Commission, the work group, or both, determine to be appropriate in order to address any overecovery or underrecovery of just and reasonable net stranded costs."

The calculation and recovery methodologies described on Attachment I are likely to produce over-recoveries of just and reasonable net stranded costs. The Restructuring Act does not specify how the LTTF should address any over- or under-recovery of just and reasonable net stranded costs that emerges from its monitoring.

One consequence of the over-recovery of such costs should be recommendations for the repeal of the Restructuring Act's provisions requiring the imposition of wires charges on customers that purchase power from alternative generation suppliers. As indicated in the Committees' initial comments in this matter, dated March 21, 2003, the wires charges afford one of the two means of recovery of just and reasonable net stranded costs; however, if the incumbent utility's capped rates and wires charges are over-recovering such costs, any justification for the imposition of wires charges on such customers would be eliminated. Therefore, the Committees' recommend consideration of the elimination of wires charges, and, if appropriate, a reduction in capped rates if the LTTF concludes from its monitoring of just and reasonable net stranded costs and their recovery that revenue from capped rates and wires charges is likely to result in an over-recovery of such costs.

We appreciate the opportunity to comment and hope the above is helpful. Please contact me if you have any questions concerning this submittal.

Very truly yours,

Edward L. Petrini

cc: State Corporation Commission
Division of Economics and Finance
(econfin@scc.state.va.us)

#635967

<u>ATTACHMENT I</u>

Submitted on behalf of the following:
Virginia Committee for Fair Utility Rates, Old Dominion Committee for Fair Utility Rates, TXI/Chaparral (Virginia) Inc., VML/VACo APCo Steering Committee, Virginia Citizens Consumer Council, Washington Gas Energy Services, Strategic Energy, Constellation New Energy, and Pepco Energy Services

- Section 56-595.C (iii) of Virginia's Electric Utility Restructuring Act ("Act") provides that the members of the Legislative Transition Task Force ("LTTF") " ... shall: ... monitor ... whether the recovery of stranded costs, as provided in § 56-584, has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs.

- To monitor an "over-recovery" or "under-recovery," the LTTF must determine and compare two amounts: first, the amount that has been, or will be, available for recovery of just and reasonable net stranded costs, and, second, the amount of just and reasonable net stranded costs.

- Section 56-584 of the Act provides for two sources of revenue for the recovery of just and reasonable net stranded costs -- capped rates and wires charges.

- Thus, the amount that has been, or will be, available for recovery of such costs is the revenue collected from wires charges and capped rates. Because the incumbent utility must collect sufficient revenue to recover its costs of providing service, the revenue available for the recovery of just and reasonable net stranded costs is the revenue from capped rates and wires charges in excess of the revenue needed by the utility to recover its costs of providing service (*i.e.*, the utility's revenues in excess of its "revenue requirement").

- The following approach recognizes both sides of the inquiry required of the LTTF – *i.e.*, (i) the amount of just and reasonable net stranded costs and (ii) the amount available for recovery of such costs through wires charges and capped rates.

> To calculate just and reasonable net stranded costs compare asset values based on the net present value of the difference between the revenues that arise from remaining in a regulated market (cost plus a fair return) and the revenues that arise in a competitive market (over the life of the assets). From this amount subtract revenues via capped rates (to the extent capped rates exceed actual and likely costs including a fair return) and wires charges to determine the over- or under-recovery of just and reasonable net stranded costs.

- The above approach represents an acceptable, administrative methodology for the calculation of both just and reasonable net stranded costs and their recovery under the Act. By reference to the "regulated market (cost plus a fair return)," the methodology incorporates traditional ratemaking concepts in a regulated environment, including consideration of a utility's regulated cost of service used in setting "just and reasonable" rates, and including concepts of "prudence," mitigation, verification, and the "netting" of stranded costs and margins. The methodology properly requires consideration of the useful life of assets.

- As is true of any administrative method of determining stranded costs, the above approach involves estimates based on long-term revenue and cost projections. Such estimates are data-intensive and highly sensitive to the underlying assumptions and models used in making them. Long-term projections, however, are almost always used, implicitly or explicitly, in valuing assets for commercial purposes. Reasonable forecasts of items affecting such calculations and the development of estimates under reasonable scenarios would be required.

- Incumbent electric utilities must make annual informational filings ("AIFs") that include specified financial information with the State Corporation Commission. The Commission reviews such

AIFs for compliance with Commission requirements for accounting and ratemaking treatment of costs and revenues. As approved by the Commission, AIFs would provide an acceptable basis for calculating a utility's historical cost of providing service and any revenues in excess of those costs that may be available for recovering stranded costs.

#634601

ATTACHMENT II

~~The~~**Dominion Virginia Power's proposed** methodology for ~~calculating~~**monitoring** "just and reasonable net stranded costs" ~~requires~~**would require** a utility to ~~determine (1)~~ **calculate and report to the LTTF, for each year of the transition period, (1)** whether there ~~is~~**was an** over- or under-recovery of stranded costs collected through the wires charges from switching customers~~, and (2)~~ **and, if so, the amount thereof, (2) the company's actual "above-market" or "potential" stranded costs exposure under capped rates, (3)** the amounts it has expended from funds available under capped rates to mitigate potential stranded costs, ~~less any~~ **and (4)** additional expenditures that negatively impact **(increase)** such costs **during the transition period**. ~~Under~~

To make the determination required under (1), a company ~~can~~**would** compare the revenue ~~actually~~ collected annually from customers via the wires charges, based on **the** projected market prices **established by the Commission,** to the revenue that would have resulted had wires charges been based on the actual market prices experienced during that year**. Projected market prices are based on actual forward market transactions and information prevailing at the time the Commission establishes wires charges, if any, to be in effect for the next calendar year. Actual market prices are based on actual market transactions ("settlement" or "spot" prices) and information prevailing at the time the energy could be delivered for sale**. If the revenue collected through the wires charges was greater than the revenue that would have resulted had the actual market price been correctly predicted, the wires charges were set too high, resulting in an over-recovery for that year. If the contrary ~~is~~**was** the case**,** then there ~~is under-recovery. In any event, whether the above two measures produce an~~**was an under-recovery.**

Under (2), a utility would track the annual potential stranded costs exposure associated with customers still paying capped rates during the transition period. After the close of each year, the Company would compare actual market prices experienced during that year (using the same data as above) to the Company's unbundled generation rate, and a determination would be made of the potential total revenue impact had all sales been made at those market prices rather than at capped generation rates. This calculation would yield the potential stranded costs exposure during each year of the transition period.

Under (3), a utility would annually report to the LTTF the amounts it has expended for mitigation of potential stranded costs and, in (4), expenditures that add to potential stranded costs.

While these measures will provide the LTTF with annual information to monitor stranded cost recovery and the Company's potential stranded cost exposure, the over- or under-recovery of a utility's total stranded costs cannot be finally determined until after July 1, 2007. **Until that date, the market prices existing at the end of the transition period cannot be determined.**

#636014

ATTACHMENT III

Stranded Costs – An Accounting Perspective

An alternative method that would indicate annual recoveries of stranded costs throughout the transition period is an accounting approach based on an earnings test mechanism. This mechanism could also be used to calculate the level of potential stranded cost exposure existing during each earnings test year. This approach would not provide for an upfront calculation of what total stranded costs are estimated to be, but could work in conjunction with the other proposed methods by providing stranded cost recovery information.

It is important to define stranded cost terms relative to this accounting approach:

- **Recovery of stranded costs**: Recovery of stranded costs occurs throughout the capped rate period to the extent actual earnings exceed costs plus a fair return. These recoveries can be calculated and monitored using the earnings test mechanism.

- **Actual stranded costs**: Defined as the underrecovery of just and reasonable generation costs in a competitive environment. Actual stranded costs would occur after the termination of capped rates and wires charges if actual generation costs exceed market prices.

- **Potential stranded costs**: Defined as the annual stranded cost exposure during the capped rate period, assuming all customers are paying market rates for generation service. This amount is represented by the difference between the recalculated, cost-based unbundled generation rates (at a fair return) less the actual market rate for the applicable year, times total annual sales.

Earnings test information is already required to be filed by IOU's under the Commission's existing rate case rules and AIF requirements. Earnings tests only recognize limited accounting or regulatory adjustments to per book amounts, and do not encompass going forward adjustments. Generally, earnings test adjustments restate per book results in order to reflect differences between GAAP and how costs are recognized for ratemaking purposes. It would be necessary to agree upon an appropriate fair rate of return to use as a benchmark ROE from which to measure earnings available for stranded cost recovery.

A bundled earnings test should be used until such time as bundled, capped rates are terminated. It is proper to use a bundled earnings test since all earnings produced under bundled, capped rates that are in excess of actual costs plus a fair return can be used to mitigate stranded cost exposure.

The determination of potential stranded costs will require a functionalized cost of service study that separates out the generation business. The cost of service study would incorporate the earnings test adjustments applicable to the test period. Actual generation costs for the test year including a fair return would then be used to calculate current, cost-based, unbundled generation rates by customer class. These generation rates would be compared to market-based rates applicable to the test year to calculate the potential stranded cost exposure for that year.

Throughout the transition period, comparisons can be made between stranded cost recoveries and potential stranded cost exposure. This will provide insight into the success of mitigation efforts, and the likelihood of whether an over or underrecovery of stranded costs will occur. By the end of the capped rate period, the earnings tests will have quantified the cumulative net recoveries of stranded costs, and we will be able to more accurately determine any stranded cost exposure going forward at that time, based on the same potential stranded cost calculations. Continued earnings monitoring after the termination of capped rates on the unbundled generation business could provide a calculation of actual stranded costs or benefits on an annual basis.

#636133

LAWYERS

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May 8, 2003
Via E-Mail

Ms. Susan Larsen
Deputy Director, Public Utility Accounting
Virginia State Corporation Commission
Tyler Building
1300 E. Main Street
Richmond, VA 23219

Re: Stranded Cost Working Group Final Comments

Dear Ms. Larsen:

Chaparral (Virginia) Inc. makes the following comments regarding the final issues as set forth in your e-mail of April 30, 2003.

> 1) LTTF requested action #9 reads: "Include in its reports to the LTTF any recommendations for legislative or administrative action that the Commission, the work group, or both, determine to be appropriate in order to address any overrecovery or underrecovery of just and reasonable net stranded costs."
>
> Please discuss whether the definitions and/or methodologies discussed by the work group might require any action as contemplated by Requested Action #9. Discuss what action may be necessary, the timing of that action, and why it is necessary.

Comment:

If the LTTF is merely seeking to discharge its responsibility under § 56-595 (C) iii to "***monitor*** . . . whether the recovery of stranded costs, as provided in § 56-584, has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs . . ." *i.e.*, to make a determination of the existence of actual or likely over- or underrecoveries, no further legislative action would be required as the authority is explicit in the statute. On the administrative side, proceedings would have to be initiated at the Commission level in order to implement whichever set of working group recommendations might be adopted to monitor stranded cost recovery.

However, should the Staff's Asset Valuation Methodology be adopted (as Chaparral believes it should), Chaparral believes that a proper analysis will reveal that an overrecovery of just and reasonable stranded costs has taken place and will likely continue under the current statutory and administrative regime. Should the LTTF wish to address and rectify such overrecoveries, new legislation would be warranted and appropriate. Such legislation should implement the reduction and/or elimination of the wires charge and the reduction of the capped rates as necessary to eliminate overrecoveries.

2) Comments regarding the proposal put forth by Ed Petrini.

Comment:

Chaparral supports the bullet points put forth by Ed Petrini. Chaparral believes that § 56-595 (C) iii requires an actual investigation into the amount of just and reasonable net stranded costs and amounts that have been and will be available for recovery of those costs. This proposal does this and includes the requisite ratemaking concepts, including prudence, mitigation, verification and netting of stranded costs and margins.

3) Comments on the Staff proposal discussed at today's meeting.

Comment:

Chaparral wishes to emphasize that the Staff "alternative method" is merely an approach to accounting based on an earnings test mechanism. Although it could be used in conjunction with the Staff's Asset Valuation Methodology (as augmented in Ed Petrini's bullet points), it is inferior as a stand-alone methodology since it performs no initial calculation of stranded costs.

4) Comments on the clarifications of Dominion's proposal.

Comment:

Dominion's proposal remains deficient in that it does not address just and reasonable net stranded costs at all and does not include the revenue effects of capped rate recoveries.

Thank you for to opportunity to address these issues.

Very truly yours,

DAVIS WRIGHT TREMAINE LLP

/S/ Michael E. Kaufmann

Michael E. Kaufmann

Counsel for Chaparral (Virginia) Inc.

WILLIAMS MULLEN

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May 8, 2003

By E-Mail

Susan Larsen, Deputy Director
Division of Public Utility Accounting
Virginia State Corporation Commission
1300 East Main Street
Richmond, VA 23219

Re: ***In the Matter of Developing Consensus Recommendations on Stranded Costs***
Case No. PUE-2003-00062

Dear Ms. Larsen:

The VML/VACo APCo Steering Committee ("Steering Committee"), by counsel, hereby offers its comments in response to the questions raised in your April 30, 2003 e-mail to the members of the Stranded Costs Work Group that was established pursuant to the Commission's directive in its March 3, 2003 *Order Establishing Proceeding*.

I. STRANDED COSTS METHODOLOGIES.

In determining one or more appropriate methodologies to calculate stranded costs and their recovery, the Legislative Transition Task Force ("LTTF") Resolution ("Resolution") requested that the Commission

> 2. By July 1, 2003, present to the Legislative Transition Task Force the work group's consensus recommendations regarding:

(a) Definitions of "stranded costs" and "just and reasonable net stranded costs."
(b) A methodology to be applied in calculating each incumbent electric utility's just and reasonable net stranded costs, amounts recovered, or to be recovered, to offset such costs, and whether such recovery has resulted in or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs; and

3. By November 1, 2003, present to the Legislative Transition Task Force the work group's consensus recommendations, developed using the methodology developed pursuant to paragraph 2 (b), regarding:

   (a) The amount of each incumbent electric utility's just and reasonable net stranded costs.
   (b) The amount that each incumbent electric utility has received, and is expected to receive over the balance of the capped rate period, to offset just and reasonable net stranded costs from capped rates and from wires charges.

A plain reading of the Resolution requires that a methodology must enable the quantification of certain amounts: *viz.*, the amount of each incumbent electric utility's just and reasonable net stranded costs;[1] the amount that each utility has received, and is expected to receive over the balance of the capped rate period to offset such costs; the amounts recovered, or

[1] This calculation is required from Va. Code §56-584, which further clarifies that such are to be recoverable only "to the extent that they exceed zero value in total for the incumbent electric utility[.]"

to be recovered, to offset such costs; and whether such recovery has resulted in or is likely to result in the over-recovery or under-recovery of just and reasonable net stranded costs.

A. Staff's Methodologies

Staff has proposed two methodologies. We offer comments on each.[2]

1. Asset Valuation Methodology

Much debate has taken place to date concerning the merits of Staff's "Asset Valuation Methodology."[3] As summarized by Staff, this methodology is used

> [t]o calculate just and reasonable net stranded costs [by] compar[ing] asset values based on net present value cash flows that arise from remaining in a regulated market (cost plus a fair return) to the net present value cash flows that arise in a competitive market (over the life of the assets). From this amount subtract recoveries via capped rates (to the extent capped rates exceed actual costs including a fair return) and wires charges to determine the over- or under-recovery of just and reasonable net stranded costs.

Notwithstanding the rather heated rhetoric concerning the complexities involved with this approach,[4] the Steering Committee supports the Asset Valuation Methodology as a calculation

[2] The Steering Committee has not commented previously on the Asset Valuation Methodology.
[3] Earlier comments have sometimes referred to this methodology as the "Spinner Methodology", due to the fact that it was introduced by Howard Spinner, the Chief of the Commission's Division of Economics and Finance.
[4] In this regard, one might consider the words of Ralph Waldo Emerson: *viz.*, that "[i]t is the last lesson of modern science, that the highest simplicity of structure is produced, not by few elements, but by the highest complexity."

that considers the true economic value of a utility's assets, in relation to a utility's costs, its present rates, and to market prices. Staff's methodology, as adjusted,[5] appropriately distinguishes between "asset values" that are calculated with reference to the recovery of a utility's costs in a regulated market, and "asset values" that are calculated with reference to the recovery of a utility's costs in a competitive market. Once these two "net present value cash flow" reference points are determined, a comparison will reveal whether a utility has any just and reasonable net stranded costs. To the extent that this comparison reveals a negative or zero value, a utility would have no stranded costs to be recovered.

A utility's revenue streams during the capped rate period are next examined to see whether the rate structure of a utility's capped rates and wires charges[6] produces revenues that result in an over- or under-recovery of the amount determined above. This approach is entirely consistent with Va. Code § 56-584, which states that

---

[5] *See* our comments *infra* concerning Attachment I to the Comments of Edward Petrini. Attachment I is submitted on behalf of the following interested parties: Virginia Committee for Fair Utility Rates, Old Dominion Committee for Fair Utility Rates (collectively, "the Committees"), TXI/Chaparral (Virginia) Inc., VML/VACo APCo Steering Committee, Virginia Citizens Consumer Council, Washington Gas Energy Services, Strategic Energy, Constellation New Energy, and Pepco Energy Services.

[6] Capped rates and wires charges are the only recovery mechanisms for just and reasonable net stranded costs that are provided for in the Restructuring Act. *See* Va. Code § 56-584. This does not necessarily preclude a utility from claiming at some time in the future that, notwithstanding the statutory scheme laid out in the Restructuring Act for the recovery of just and reasonable net stranded costs, the utility is entitled to relief. *Cf.* U.S. Const. amend. V ("...nor shall private property be taken for public use, without just compensation."); *see also See Pacific Gas & Electric Co. v. Lynch*, 216 F.Supp.2d 1016, 2002 WL 182474 (No. Dist. Cal. 2002).

> Just and reasonable net stranded costs, to the extent that they exceed zero value in total for the incumbent electric utility, shall be recoverable by each incumbent electric utility provided each incumbent electric utility shall only recover its just and reasonable net stranded costs through either capped rates as provided in § 56-582 or wires charges as provided in § 56-583.

Accordingly, no legislative changes are necessary to implement the Asset Valuation Methodology, as adjusted.[7]

2. "Earnings Test" Methodology

Staff provides an alternative method that would indicate annual recoveries of stranded costs throughout the transition period. Staff has based this approach upon the earnings test mechanism found in the Commission's existing rate case rules and Annual Informational Filing ("AIF") requirements. Staff reports that this mechanism also could be used to calculate the level of potential stranded cost exposure existing during each earnings test year.

Staff explains that this approach would not provide for an up-front calculation of what a utility's estimated total stranded costs would be; however, the approach could work in conjunction with other proposed methods by providing stranded cost recovery information.

Staff's approach focuses on three areas:

[7] Once these figures are derived, and the results show an under- or over-recovery of just and reasonable net stranded costs, the General Assembly may need to consider whether additional legislation is needed.

- **Recovery of stranded costs**: Recovery of stranded costs occurs throughout the capped rate period *to the extent actual earnings exceed costs plus a fair return*. These recoveries can be calculated and monitored using the earnings test mechanism.

Notably, the Earnings Test methodology takes into consideration a utility's prudently incurred costs, plus a fair return on the utility's investment. Prior to the passage of the Virginia Electric Utility Restructuring Act,[8] it was the duty of each public utility subject to the regulation of the Commission to "furnish reasonably adequate service and facilities at just and reasonable rates to any person, firm or corporation along its lines desiring same." Va. Code § 56-234. In exchange for this obligation to serve, the regulated utility was entitled "to set rates that will cover both operating costs and provide an opportunity to earn a reasonable rate of return on the property devoted to the business."[9] Historically, the goal of ratemaking has been to obtain the most efficient service available for ratepayers, and to protect them from unreasonable costs. *See, e.g., El Paso Natural Gas Co. v. FPC*, 281 F.2d 567, 573 (5th Cir.)("It is the obligation of all regulated public utilities to operate with all reasonable economies."), *cert. denied*, 366 U.S. 912 (1960).

[8] Va. Code Title 56, Chapter 23, § 56-576 *et seq*. (as amended, the "Restructuring Act").
[9] Charles F. Phillips, Jr., *The Regulation of Public Utilities*, 176 (3d Ed. 1993).

In this context, to the extent a utility's capped rates produce revenues in excess of its costs during the capped rate transition period, a pool of dollars will be created and collected by the utility. A utility can use this pool of dollars to offset actual stranded costs in the future, following the expiration of capped rates.

- **Actual stranded costs**: Defined as the underrecovery of just and reasonable generation costs in a competitive environment. Actual stranded costs would occur after the termination of capped rates and wires charges if actual generation costs exceed market prices.

The Steering Committee generally agrees with this concept as framed. It would be this amount against which the pool of dollars, if any, would be applied to provide relief from a utility's above-market costs in a competitive environment.

- **Potential stranded costs**: Defined as the annual stranded cost exposure during the capped rate period, assuming all customers are paying market rates for generation service. This amount is represented by the difference between the recalculated, cost-based unbundled generation rates (at a fair return) less the actual market rate for the applicable year, times total annual sales.

As indicated, Staff proposes a calculation of "potential stranded cost exposure" that is similar to that proposed by Dominion Virginia Power ("DVP" or "Dominion"), discussed below. Staff's proposal with respect to the measurement of "potential stranded costs" will be addressed in connection with Dominion's proposal.

B. Dominion Virginia Power's Methodology (Revision of 4/28/03)

As revised, Dominion Virginia Power's ("DVP" or "Dominion") proposed methodology for monitoring "just and reasonable net stranded costs"

> would require a utility to calculate and report to the LTTF, for each year of the transition period, (1) whether there was an over- or under-recovery of stranded costs collected through the wires charges from switching customers and, if so, the amount thereof, (2) the company's actual "above-market" or "potential" stranded costs exposure under capped rates, (3) the amounts it has expended from funds available under capped rates to mitigate potential stranded costs, and (4) additional expenditures that negatively impact (increase) such costs during the transition period.

To make the determination required under (1), DVP proposes that a company would compare the revenue it collected annually from switching customers via the wires charges, based on the projected market prices established by the Commission, to the revenue that would have resulted had wires charges been based on the actual market prices experienced during that year.

While such calculations may be of use in certain circumstances, this approach fails to examine a critical component of stranded costs: *viz.*, a utility's <u>costs</u>. Instead, Dominion's calculations would determine the difference between what the Commission sets as a benchmark for an upcoming year, and what prices actually prevailed during the period. The method says nothing about the revenues produced in relation to a utility's costs.

Dominion's proposal, as clarified, fails to provide a methodology for calculating just and reasonable net stranded costs, nor does it calculate such costs or the amounts available for their recovery. Thus, it fails to meet the requirements of the Resolution.[10] Dominion's methodology merely focuses on the difference between revenues collected from customers through a utility's wires charges, on the one hand, and revenues that would been produced had the utility's wires charges been based upon "actual" market prices for the year in question. Dominion's methodology also fails to make any calculation of the pool of dollars that are created and collected to the extent a utility's capped rates produce revenues in excess of its costs during the capped rate transition period. As a utility can and should use this pool of dollars to offset actual stranded costs (if any) incurred in the future following the expiration of capped rates, DVP's methodology is deficient.

[10] Dominion's proposal, as clarified, also calls for annual calculations related to the "amounts it has expended from funds available under capped rates to mitigate potential stranded costs, and ...additional expenditures that negatively impact (increase) such costs during the transition period." While a utility should calculate and report such expenditures annually to the LTTF, such expenditures should be subject to verification and examination to determine whether they were prudently incurred. Dominion's proposed calculations do not provide a methodology to calculate just and reasonable net stranded costs, however, nor do they provide a means for recovery.

Dominion's present approach also includes an annual calculation of "the company's actual 'above-market' or 'potential' stranded costs exposure under capped rates." This feature, which was not included in DVP's prior proposals, is summarized by Dominion as follows:

> After the close of each year, the Company would compare actual market prices experienced during that year (using the same data as above) to the Company's unbundled generation rate, and a determination would be made of the potential total revenue impact had all sales been made at those market prices rather than at capped generation rates. This calculation would yield the potential stranded costs exposure during each year of the transition period.

Dominion's approach appears to share certain features with the Staff's "Earnings Test" methodology. If Dominion proposes that this calculation be used as a proxy for a utility's market risk, it fails to account for all of the variables that must be in place for all sales to be made at market prices. For example, transmission import limitations preclude Dominion from losing 100% of its retail market share to other generators outside Virginia. These limitations dictate that even with customer choice, Dominion is assured that it will have a market in Virginia for some, if not all, of its generation.

Moreover, such calculations will become more complicated if, and how, locational marginal pricing ("LMP") and financial (firm) transmission rights ("FTRs") are introduced. Presently, a utility's rates socialize the cost of serving customers in different locations when there is congestion on the utility's transmission system. With LMP, these cost differentials become visible price signals that are supposed to encourage infrastructure investment (generation and/or transmission) and/or load management, while FTRs are designed to act as a hedge against the costs of transmission congestion. We do not know at this time how a utility's particular LMP/FTR regime will impact its revenues, or the prices its customers will pay.[11]

If Dominion's proposed calculation is referring to "settlement" or "spot market" prices "experienced during the year" as seen from the incumbent electric utility's perspective, a utility makes out better financially to the extent those market prices are below the utility's capped rate sales, and there is no "exposure" to lost revenues. If, on the other hand, those "settlement" or "spot market" prices are above the utility's capped rates, this only serves to highlight the "exposure" the utility's retail customers may face in a transition to market prices.

The major shortcoming to this proposed calculation is that it does not calculate either "stranded costs" or "just and reasonable net stranded costs," and it says nothing about the recovery of such costs through either capped rates or wires charges. While this calculation might be helpful if modified to reflect a true-up of calculations related to customers that switch

[11] HB 2453 requires a utility to prepare a cost-benefit study in connection with its application to join an RTE. The Commission's review of this study should yield valuable information for the LTTF to consider.

suppliers,[12] it will do little as is to respond to the needs of the LTTF pursuant to § 56-595C(iii), and should not be adopted without modification.

C. The Committees' Methodology

As indicated in the comments of the Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates (collectively, "the Committees"), the Steering Committee supports the proposal set forth in Attachment I to the Committees' comments. Rather than two stand-alone methodologies, Attachment I incorporates the best features of Staff's Asset Valuation Methodology and the "Earnings Test Methodology" described above, as modified. This approach is consistent with the Restructuring Act and the Resolution, and enjoys the support of several stakeholders.

II. RECOMMENDATIONS FOR LEGISLATIVE OR ADMINISTRATIVE ACTION.

The Resolution calls for the Commission to include in its reports "any recommendation for legislative or administrative action that the Commission, the work group, or both, determine

[12] This, in effect, appears to be what Dominion proposes to calculate under calculation (1). No legislation is needed for the Commission this into account, as such adjustments can be factored into the Commission's determination of projected market prices of generation for the year following a year with an over- or under-recovery.

to be appropriate in order to address any overecovery or underrecovery of just and reasonable net stranded costs."

While the Restructuring Act calls for the LTTF to monitor any over-or under-recoveries of just and reasonable net stranded costs, it does not specify any action to be taken in response to such determinations. If, as anticipated, the calculation and recovery methodologies indicate an over-recovery of just and reasonable net stranded costs, the Restructuring Act should provide for the Commission to take action, either by reducing or eliminating a utility's wires charges, if any, and/or by reducing a utility's capped rates. Additional legislative or administrative actions may also be called for as more information related to the structure and operation of wholesale and retail electric markets becomes available.

Thank you for the opportunity to provide these comments.

Very truly yours,

/s/ Thomas B. Nicholson

cc: State Corporation Commission Division of Economics and Finance
(econfin@scc.state.va.us)

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May 8, 2003

Susan Larsen
Deputy Director, Public Utility Accounting
Virginia State Corporation Commission
Tyler Building
1300 E. Main St.
Richmond, Virginia 23219

Dear Ms. Larsen:

Per the Commission Staff's instructions on April 30, 2003, Constellation NewEnergy, Inc. ("NewEnergy") herby provides its comments to the Virginia stranded cost working group on the following proposed conceptual models to be used to calculate net stranded costs, as well as recommendations on proposed legislation. Constellation NewEnergy, Inc. expresses its appreciation of the Commissions efforts to facilitate the working group's efforts to quantify net stranded costs.

If you have any questions regarding these comments, please do not hesitate to call at 215-320-1164.

Sincerely,

Eric W. Matheson
Director, State Regulation
Mid-Atlantic Region,
Constellation NewEnergy, Inc.

I. Recommendations for legislative or administrative action

In order to clarify that wires charges, as calculated under PUE 2001-0306, should be zero in the event that net stranded costs are determined to be zero or actually net stranded benefits, NewEnergy recommends that the following clarifying language be added to the Virginia Electricity Restructuring Act:

> Consistent with Section 56-595(C), in the event the LTTF, in consultation with the Commission, the Office of the Attorney General, incumbent electric utilities, suppliers, and retail customers, determines that the recovery of stranded costs has resulted or is likely to result in the over-recovery of just and reasonable net stranded cost, then the applicable utility's wires charge shall be zero until such time that the Commission revises its determination.

NewEnergy asserts that this clarifying language is just and reasonable. It does not prevent the just and reasonable collection of net stranded costs. This language envisions that utilities will have an opportunity to demonstrate whether any just and reasonable stranded costs exist, calculate the amount of stranded costs and then to compare this amount with stranded cost recovery to date under the process being undertaken in PUE 2003-00062, and agreed to by the LTTF. To the extent it is reasonably determined that stranded cost recovery has exceeded net stranded costs, then wires charges would be eliminated until such time as the utility can demonstrate to the Commission that net stranded costs are positive using the methodologies employed by the LTTF. In any event, stranded cost recovery in accordance with the existing statutory requirements would be terminated on July 1, 2007 at the latest.

The additional statutory language should be enacted and then implemented immediately so the Commonwealth consumers of electricity are not forced to pay wires charges to recover stranded costs that, in fact, are determined to be nonexistent.

II. Comments on the Methodology put forward by VCFUR and ODCFUR

NewEnergy concurs strongly that the general principles outlined in VCFUR/ODCFUR's proposed methodology are a just and reasonable guide to use in determining whether collections under the existing bundled rates and wires charges will result in an over-recovery or under-recovery of any net stranded cost. The VCFUR/ODCFUR proposal further acknowledges that such estimates of net stranded costs are data intensive and highly sensitive to the underlying assumptions and models used in making them. To this point, NewEnergy notes that this requirement was implemented in a number of jurisdictions, and has not formed a barrier to the ultimate determination of net stranded costs. In support of this assertion, NewEnergy represents that many jurisdictions have used, what Staff refers to as the "Asset Valuation Methodology".

In Pennsylvania, the Pennsylvania Public Utility Commission was charged with determining a just a reasonable estimate of stranded costs to be collected from customers.

As part of this process, an administratively determined estimate of stranded cost was calculated using an asset valuation methodology by the various intervening parties, and the Commission ruled on testimony provided in these proceedings. Ultimately, most of the stranded cost valuations were determined by settlement after the hearing process was conducted. These utilities included:

Company Name	Docket
Peco Energy	R-00973953
Pennsylvania Power & Light	R-00973954
West Penn Power	R-00973981
Duquesne Light Co.	R-00974104
Metropolitan Edison Co.	R-00974008
Pennsylvania Electric Co.	R-00974009
Pennsylvania Power Co.	R-00974149

NewEnergy attaches hereto the Pennsylvania Power & Light ALJ Decision as an example of such an administrative process for calculation of stranded costs.

In Texas, stranded costs were initially administratively determined in the Excess Cost Over Market Model (ECOM Model). Later, these estimates are to be reconciled to actual market values of the assets in the market place. As a result of this model, stranded costs were determined to be negative (net stranded benefits) during the initial estimates. These utilities included:

Reliant Energy
Texas Utilities Electric Co.
Central Power & Light Co.
Energy Gulf States

A number of other jurisdictions established stranded costs through market valuation methods based on the sale of the generation assets. Some examples include various utilities in California (San Diego Gas & Electric Co.), Montana (Montana Power Co.), and Maryland/District of Columbia (Potomac Electric Power Company).

NewEnergy strongly urges the LTTF to undertake its obligations under Section 56-595(C), and to proceed with the task at hand, consistent with the principles outlined in the VCFUR/ODCFUR proposal, so that consumers in the state are not burdened by potentially unjust and insufficiently quantified net stranded costs.

III. Comments on the Methodology put forward by Virginia Power

The latest proposals put forth by Virginia Power have the same inherent weaknesses described in the prior comments provided by NewEnergy. Rather than repeat those comments, NewEnergy recommends that the Staff incorporate those comments by reference. In short, the Virginia Power proposal (1) fails to recognize stranded benefits, (2) incorporates a stranded cost methodology that clearly overestimates stranded costs and is fundamentally flawed, (3) fails to determine any stranded cost recovery attributable to collections under capped rates, and (4) provides no means of terminating or reducing wires charges prior to the end of transition period regardless of the level of stranded cost recovery.

IV. Comments on the Methodology put forward by Commission Staff

NewEnergy believes that the methodologies outline in the Staff Proposal labeled "Stranded Costs – An Accounting Perspective", provide a valid means of determining recovery of stranded costs. However, the provisions dealing with the estimation of actual stranded costs should be calculated using the heretofore proposed "Asset Valuation Methodology" as described by Staff.

Recovery of Stranded Costs: Staff properly asserts that actual recovery of stranded costs is best determined by using a bundled earnings test during the capped rate period. This test would compare the excess of capped rates over the actual costs plus a fair return. To this amount would be added any wires charge collections. Commission staff appears to have the technical ability to make such calculations during period from January 1, 2001, to the current period. An estimate of stranded cost recovery could then be extrapolated to the end of the transition period by using an appropriate test period to be determined by Staff. NewEnergy supports this facet of the Staff proposal.

Actual Stranded Costs: Staff's definition of Actual Stranded Costs contemplates that there needs to be a specific calculation of the market value of generation assets versus the embedded cost of those assets to determine the amount of Stranded Costs. The Staff should adopt the Asset Valuation Methodology described in the VCFUR/ODCFUR proposal to ensure that the calculation is done thoroughly. Specifically, the calculation must be robust enough to reflect situations in which the market value of the generation assets exceeds the embedded costs, in which case there would be no stranded costs.

Potential stranded costs: Staff defines potential stranded costs as the cost exposure during the capped rate period, assuming all customers are paying market rates for generation service. NewEnergy asserts that this calculation is of no consequence in the presence of wires charges. If wires charges are collected, there are no stranded costs. Thus, this quantity is only relevant if wires charges are waived, or are zero.

If wires charges are waived, then there is the possibility for additional "potential stranded costs" during the transition period. If the LTTF is to undertake such a calculation, it must ensure that the actual market prices used are comparable to the service embedded in the cost-based unbundled generation rates. For example, if the unbundled generation rates reflect a retail price, then appropriate market-based retail cost elements should be added to any wholesale market rates to reflect a competitive retail price. In any case, if the retail prices of a utility are below the retail market prices as determined in this case, any potential stranded costs should be set to zero.

Overall Summary

If used as a means of calculating stranded cost **recovery**, the Staff's earning test proposal would work well because it takes into account excess revenue collections under capped rates as well as revenue collections via wires charges. Both types of revenues must be taken into account to ensure that customers do not over compensate the utility for its demonstrated stranded costs. However, neither the Staff's Accounting Perspective nor Virginia Power's methodology provides a reasonable means of determining net stranded **costs**. Net stranded costs must be determined using forward extrapolations of market prices in order for there to be any benefit to consumers. If only a historical look-back on actual costs is used in this proceeding, consumers will not receive any benefit from this LTTF effort. Conversely, if net stranded costs are reasonably projected using the best available forward projections of energy prices using an asset valuation methodology; consumers could have a reasonable chance of benefiting from competition during the transition period.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF	:	
PENNSYLVANIA POWER & LIGHT COMPANY	:	
FOR APPROVAL OF RESTRUCTURING PLAN	:	Docket No. R-00973954
UNDER SECTION 2806 OF	:	
THE PUBLIC UTILITY CODE	:	

RECOMMENDED DECISION

Before
George M. Kashi
Administrative Law Judge

INTRODUCTION

A. Summary

On December 3, 1996, Governor Ridge signed into law the Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. §§ 2801 et. seq. (the "Act"). The Act fundamentally restructures the provision of retail electric service in Pennsylvania by mandating the phase-in of customer choice of electric generation supplier ("EGS") beginning January 1, 1999.

The Act establishes four critical components for a fair and balanced transition to competition:

1. The establishment of reasonable terms and conditions for open access retail competition;
2. The calculation and recovery of reasonable stranded costs;
3. The establishment of unbundled rates for the generation, transmission and distribution of electricity; and
4. The provision of continued customer protections, particularly the continuation of safe and reliable service and programs for the assistance of low-income customers.

PP&L in its Restructuring Plan filing, as revised during this proceeding:

> (a) proposed the unbundling of its rates and establishment of competitive transition charges ("CTCs") and specific tariff provisions to ensure customers direct access to all licensed EGSs; (b) projected its transition costs under the Act at $4.5 billion; (c) proposed a plan to meet its universal service obligations, including a mechanism to recover the costs of those obligations; (d) described the implementation of a consumer education program; and (e) proposed procedures for implementing PP&L's responsibilities as provider of last resort under 66 Pa.C.S. § 2807(e)(3).

See PP&L M.B. pp. 1-9.

By and large we found the petition to be just, reasonable, balanced and in compliance with the intent of the Act. Our major exception is the stranded costs. We find the adjustments of OTS to stranded costs, as modified, to most nearly reflect our own position. Additionally we felt the need for a true up reconciliation procedure. Our uppermost concern throughout were those ratepayers whose marginal positions leaves them without an ability to "compete."

The task before us in managing the case, marshalling the evidence, assessing the briefs and preparing this recommended decision was at best daunting. We have tried to keep it simple in recognition that to be able to cross all the "t's" and dot all the "i's" in a procedure that changes the history of the past seventy (75) years is virtually if not completely impossible. We expect that we are looking at surmounting one barrier after another for the next serveral years. However, that should not deter us from moving forward one step at a time; if that step can be in the same direction. Problems are only opportunities dressed in work clothes.

We have tried not to break new ground where it was not necessary. We found the differences between PP&L and PECO to be significant. Therefore we found the PECO decision, its reconsideration order and various compliance orders to be not directly on point.
We viewed those decisions as stand alone decisions and not controlling precedent.

Because of the volume of material involved in this proceeding not all issues raised by the thirty-nine(39) parties are discussed below. If an issue is not presented it was considered and rejected without discussion.

B. **History of the Proceedings**

In accord with the PUC Order entered January 24, 1997, at. M-00960890.F05, PP&L filed its Restructuring Plan on April 1, 1997.

Copies of the filing were served on all active participants in PP&L's last general base rate investigation at Docket No. R-00943271 and provided to any person who requested a copy. PP&L provided notice of its Restructuring Plan filing to all customers by bill insert beginning with the April 1997 billing cycle. The Company further provided a one-page notice of its filing to all individuals on the Commission's Executive Director's Stakeholder list. In addition, notice of the filing was published in newspapers of general circulation throughout PP&L's service territory.

PP&L's Restructuring Plan filing was assigned to this administrative law judge, and a first prehearing conference was convened in Harrisburg on April 18, 1997. We permitted Thirty nine (39) parties to intervene in this proceeding. Of that group, seventeen (17) intervenors have maintained active party status. In addition, formal complaints against the Company's Restructuring Plan were filed by the OCA, PPLICA and the Environmentalists.

The following are active parties in Docket No R-00973954: Office of Consumer Advocate (OCA), Office of Small Business Advocate (OSBA), Office of Trial Staff (OTS), Allegheny Power, American Association of Retired Persons (AARP), Commission on Economic Opportunity (CEO), Delmarva Power & Light, Enron Power Marketing Inc.(Enron), Environmentalists, Local 1600, International Brotherhood of Electric Workers (IBEW), Eric Epstein, Gilberton Power, Mid-Atlantic Power Supply Association (MAPSA), New Energy Ventures (NEV), Pennsylvania Petroleum Association (PPA), PP&L Industrial Customer Alliance (PPLICA), Schuylkill Energy Resources (SER), and United States Department of Defense.

The following are inactive parties in Docket No R-00973954: Allegheny Electric Cooperative, American Energy Solutions, Anthracite Regional Power Producers (ARIPPA), Bethlehem Steel, Center for Energy and Economic Development (CEED), Duke Energy Trading Marketing, Dupont Power Marketing, Electric Clearinghouse Inc., ERI Services Inc., GPU Energy, Kraft Foods, Noram Energy Management, PECO Energy Company, Pennsylvania Association of Plumbing Heating & Cooling Contractors (PAPHCC), Pennsylvania Electric

Consumers Council, PP&L Rate Payers Association, and Pennsylvania Retailers Association, Vastar Power Marketing.[1]

PP&L submitted with its filing extensive supporting information, including the direct testimony and supporting exhibits of seventeen (17) witnesses and responses to the Commission's filing requirements. PP&L also responded to numerous interrogatories and data requests. In addition, an informal technical conference was held in Harrisburg on May 2, 1997, at which PP&L made available several of its witnesses to answer questions and further explain their testimony.

On July 2, 1997, the intervenors submitted extensive direct testimony addressing almost every aspect of PP&L's Restructuring Plan. On August 5, 1997, PP&L responded to the intervenors' direct testimony by filing rebuttal testimony and exhibits sponsored by twenty witnesses. A number of the intervenors submitted surrebuttal statements on August 15, 1997.

Evidentiary hearings were held in Harrisburg on August 18-22 and August 25-29, 1997 and on September 9, 1997. During those hearings 284 exhibits and the testimony of 57 witnesses were admitted into evidence. The transcribed record, which includes the cross examination of the direct testimony at evidentiary hearing, consists of 2,337 pages. The evidentiary record was closed on September 9, 1997.

Thirteen (13) public input hearings were held during the weeks of May 30, 1997 and September 2, 1997. Public input hearings were held in Allentown (June 2), Bethlehem (June 2 and September 3), Harrisburg (May 30 and September 3), Hazelton (June 4), Lancaster (May 30 and September 2), Pottsville (June 4), Scranton (June 3 and September 4), Williamsport (June 5), and Wilkes-Barre (June 3). A total of 75 persons testified at the public input hearings.

Following the evidentiary hearings, we directed the parties to enter into settlement discussions and ordered the intervenors to present PP&L with a unified proposal for settlement. Tr. 1593 (8/26/97). To accommodate those discussions the post-hearing briefing and decision schedule was extended several times. Orders extending the briefing schedule and the date for Commission decision in the case were issued on September 12, 1997, October 17, 1997, November 25, 1997 and December 24, 1997.

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[1] See Table A to PP&L Main Brief which contains a list of the parties.

Main Briefs and supplements were filed on February 13, 1998. Reply Briefs were filed on February 27, 1998. Our Recommended Decision is now due[2].

FINDINGS OF FACT

PROCEDURAL HISTORY

1. On December 3, 1996, Governor Ridge signed into law the Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. §§ 2801 et. seq. (the "Act"). The Act fundamentally restructures the provision of retail electric service in Pennsylvania by mandating the phase-in of customer choice of electric generation supplier ("EGS") beginning January 1, 1999.

2. Section 2806 of the Act requires Pennsylvania jurisdictional utilities to file Restructuring Plans for Commission approval. By Order entered January 24, 1997 at Docket No. M-00960890.F05, the Commission directed PP&L to file its Restructuring Plan on April 1, 1997. In accordance with the Commission's January 24, 1997 Order, PP&L filed its Restructuring Plan on April 1, 1997.

3. PP&L in its Restructuring Plan filing, as revised during this proceeding: (a) proposed the unbundling of its rates and establishment of competitive transition charges ("CTCs") and specific tariff provisions to ensure customers direct access to all licensed EGSs; (b) projected its transition costs under the Act at $4.5 billion; (c) proposed a plan to meet its universal service obligations, including a mechanism to recover the costs of those obligations; (d) described the implementation of a consumer education program; and (e) proposed procedures for implementing PP&L's responsibilities as provider of last resort under 66 Pa.C.S. § 2807(e)(3) ("Last Resort Service").

4. Copies of the filing were served on all active participants in PP&L's last general base rate investigation at Docket No. R-00943271. PP&L provided notice of its Restructuring Plan filing to all customers by bill insert beginning with the April 1997 billing cycle and all persons who requested a copy. The Company further provided a one-page notice of its filing to all individuals on the Executive Director's Stakeholder list. In addition, notice of the filing was published in newspapers of general circulation in PP&L's service territory.

5. Thirty-nine parties were permitted to intervene in this proceeding. Of that group, seventeen intervenors have maintained active party status. In addition, formal complaints against the Company's Restructuring Plan were filed by the OCA, PPLICA and the Environmentalists.

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2 Please note: In drafting this decision, we have taken the positions of the parties nearly verbatim from the briefs filed in this case and other documents due to the voluminous briefs and record and exigencies of time. While we could have produced a much lengthier document, we went with an alternative that places more of the burden on the reader unfamiliar with the record. We have tried not to misstate the positions of parties. Given these alternatives, the better course appears succinctness and brevity. As we stated in our first briefinging order "shorth is better than length".

As stated earlier we do not include the position of every party on every issue in this decision. We do not include a position if it is a cursory handling of an issue, adopts the position of another party without adding argument, or does not adhere to the common brief outline which we directed the parties to follow. Given the voluminous briefs and record, we could not always take the time to hunt for a party's position if it did not appear in the appropriate place in the commonlist of issues outline produced August 5, 1997. Where possible, and to keep the decision at a manageable length, at times we shorten a position and indicate that it is similar to a position already stated. In instances where a party fails to properly identify statements or exhibits as marked for the record, we have eliminated those citations and we refer the reader to the party's brief on the subject.

6. Evidentiary hearings were held in Harrisburg on August 18-22 and August 25-29, 1997 and on September 9, 1997. During those hearings 284 exhibits and the testimony of 57 witnesses were admitted into evidence. The transcribed record of the evidentiary hearing consists of 2,337 pages. The evidentiary record was closed on September 9, 1997.

7. Thirteen public input hearings were held during the weeks of May 30, 1997 and September 2, 1997. Public input hearings were held in Allentown (June 2), Bethlehem (June 2 and September 3), Harrisburg (May 30 and September 3), Hazleton (June 4), Lancaster (May 30 and September 2), Pottsville (June 4), Scranton (June 3 and September 4), Williamsport (June 5), and Wilkes-Barre (June 3).

I. CONTEXT OF RESTRUCTURING

8. Electric companies have been viewed as natural monopolies in Pennsylvania since the adoption of the Public Service Company Law of July 26, 1913, P.L. 1374 (repealed), as amended by section 4 of the Act of June 3, 1933, P.L. 1526, 66 P.S. §201-2 (repealed).

9. The Public Service Law and its successors recognize that in exchange for a monopoly to provide service in an exclusive service territory, public utilities were both exempted from competition and obligated to provide service within that service territory. Regulation of rates and service was determined to be necessary to replace the lack of competition

10. An overriding theme of traditional monopoly regulation of electric utilities has been described as the regulatory bargain or regulatory compact. PP&L St. 1, pp. 11-12.

11. Pursuant to this system of regulation,Utilities have invested billions of dollars to construct generating stations to meet the reasonably projected needs of customers in its service territory. These investments previously have been reviewed by the Commission and adjudged to be prudent expenditures. Accordingly, under a continuation of regulated monopoly service, PP&L and its investors would have had an opportunity to recover both a return of, and a reasonable return on, such investments to provide service to customers.

12. Economic circumstances have changed, however, leading the General Assembly to conclude that the generation of electricity, as distinguished from its transmission and distribution, is no longer a natural monopoly. PP&L St. 18-R, pp. 21-22.

13. In 1992 Congress passed the Energy Policy Act which specifically empowered the Federal Energy Regulatory Commission ("FERC") to order public and privately owned utilities to grant access to their transmission systems for qualified entities engaging in wholesale power transactions. 16 U.S.C. §824(j),(k).

14. The FERC dramatically expanded the availability of transmission by issuing, in 1996, Order No. 888 requiring the public utilities to unbundle wholesale contracts and offer open access non-discriminatory transmission to all eligible customers — including retail customers in states implementing retail competition — while providing for the recovery of stranded costs incurred as a result of opening up the transmission system.

15. The significant metamorphosis in the economics of producing electric power has led the General Assembly to conclude that generation of electricity can be provided more efficiently (at lower costs) under a competitive system. As the General Assembly concluded:

> Because of advances in electric generation technology and federal initiatives to encourage greater competition in the wholesale electric market, it is now in the public interest to permit retail customers to obtain direct access to a competitive generation market as long as safe and affordable transmission and distribution service is available at levels of reliability that are currently enjoyed by the citizens and businesses of this Commonwealth. 66 Pa.C.S §2802(3).

16. The Act substitutes a competitive system for determination of the generation prices for the previously employed regulated system.

17. The Act contains declarations of policy which set forth the reasons that the General Assembly has directed the restructuring of the electric industry in Pennsylvania. 66 Pa.C.S.§2802. The Act also contains specific standards for restructuring of the electric industry. 66 Pa.C.S. §2804. These declarations and standards set the bounds within which the restructuring of the electric industry is to be conducted and within which the issues in this proceeding must be resolved.

18. In adopting the Act, the General Assembly recognized the need for a fair transition from regulation to competition. 66 Pa. C.S. §2802(9).

19. In section 2802(12), the General Assembly declares that:

> The purpose of this chapter is to modify existing legislation and regulations and to establish standards and procedures in order to create direct access by retail customers to the competitive market for the generation of electricity while maintaining the safety and reliability of the electric system for all parties. Reliable electric service is of the utmost importance to the health, safety and welfare of the citizens of the Commonwealth. Electric industry restructuring should ensure the reliability of the interconnected electric system by maintaining the efficiency of the transmission and distribution system. 66 Pa.C.S. §2802(12).

20. In order to protect customers while transitioning to a competitive market for generation of electricity, Section 2804(4) of the Act provides for rate caps. These rate caps are designed to protect customers from increases in rates over the levels in effect at the time of adoption of the Act, that might result from the transition to a competitive market.

21. The Act also recognizes the fact that electric utilities and their investors have invested billions of dollars in generating facilities, that some of these costs may not be recovered under a competitive system and that electric utilities should be permitted to recover such costs during the transition period to the extent possible within the rate cap. 66 Pa.C.S. §2802(15).

22. The Act establishes the manner in which competition will be conducted. In this regard the Act provides that:

> This chapter requires electric utilities to unbundle their rates and services and to provide open access over their transmission and distribution systems to allow competitive suppliers to generate and sell electricity directly to consumers in this Commonwealth. The generation of electricity will no longer be regulated as a public utility function except as otherwise provided for in this chapter. Electric generation suppliers will be required to obtain licenses, demonstrate financial responsibility and comply with such other requirements concerning service as the commission deems necessary for the protection of the public. 66 Pa.C.S. §2802(14).

23. To implement open access, the Act sets forth certain standards to which the Commission must adhere:

> The commission may permit, but shall not require, an electric utility to divest itself of facilities or to reorganize its corporate structure. 66 Pa.C.S. §2804(5).
>
> Consistent with the provision of section 2806, the commission shall require that a public utility that owns or operates jurisdictional transmission and distribution facilities shall provide transmission and distribution service to all retail electric customers in their service territory and to electric cooperative corporations and electric generation suppliers, affiliated or nonaffiliated, on rates, terms of access and conditions that are comparable to the utility's own use of its system. 66 Pa.C.S. §2804(6).
>
> The commission shall require that restructuring of the electric utility industry be implemented in a manner that does not unreasonably discriminate against one customer class to the benefit of another. 66 Pa.C.S. §§2804(7).

24. In addition to providing for a retail access pilot (66 Pa.C.S. § 2806(G)), the General Assembly also obligated each electric distribution company to implement, in conjunction with the Commission, a consumer education program that "shall provide consumers with the information necessary to help them make appropriate choices as to their electric service." 66 Pa.C.S. § 2807(d)(3).

25. The Act further seeks to protect customers who, for any number of reasons, do not or cannot obtain service from a competitive electric supplier. In this regard, the Act contains specific policy determinations concerning continuation of programs that currently assist low-income customers (66 Pa.C.S. §2802(10) and other public purpose programs. 66 Pa.C.S. §2802(17).

26. The Act also contains requirements applicable to electric companies that are intended to provide all customers with reliable transmission and distribution service and to provide all customers with a supplier of last resort. 66 Pa.C.S. §2802(16).

II. LEGAL AND POLICY FOUNDATIONS OF STRANDED COST RECOVERY

27. The Act addresses stranded costs in three different ways. First, the "Declaration of Policy," Section 2802(15), establishes the general need for and appropriateness of recovery by electric distribution companies of their stranded costs as follows:

> In establishing the standards for the transition to and creation of a competitive electric market, heretofore, public utilities generally have had an obligation to serve customers within their defined service territories; consistent with that obligation, have undertaken long-term investments in generation, transmission and distribution facilities in order to meet the needs of their customers; and have entered into long-term power supply agreements as required by Federal law. In many instances, these investments and agreements have created costs which may not be recoverable in a competitive market. The commission is empowered under this chapter to determine the level of transition or stranded costs for each electric utility and to provide a mechanism, the competitive transition charge, for recovery of an appropriate amount of such costs in accordance with the standards established in this chapter.

Second, the Act provides a general definition of "stranded costs." Section 2803 defines "stranded costs" to be:

> An electric utility's known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market and which the commission determines will remain following mitigation by the electric utility.

Third, Section 2804(14) of the Act mandates an "orderly" transition to competition designed to:

> protect electric system reliability, be fair to ratepayers and provide the investors in Pennsylvania electric utilities with a fair opportunity to fully recover the amount of transition or stranded costs that the Commission determines to be just and reasonable.

28. Sections 2802(15), 2803 and 2804(14) of the Act mandate that the Commission allow recovery of a level of stranded costs determined to be just and reasonable. In adopting these provisions, the General Assembly has balanced the interests of electric utilities and ratepayers in an appropriate manner. The Act seeks to attain, on one hand, the benefits for customers of low-cost electric generation that is becoming available, as explained above, from technological advances and reduced fuel prices. On the other hand, the Act permits electric utilities to recover their prudently-incurred costs, that would be recoverable under the prior system of regulation, but which may not be recoverable under a competitive regime.

29. Regulated utilities in Pennsylvania operated under a requirement of mutual obligations, regardless of whether those obligations are referred to as a "regulatory compact," "regulatory bargain," "understanding," or something else. The essence of that initial obligation was that utilities had a fair opportunity to recover their prudently-incurred investments in facilities used to meet their obligation to serve all customers. PP&L St. 1, pp. 11-12; PP&L St. 18-R, p. 10.

30. The General Assembly expressly recognizes the general principles of this bargain or understanding in the Declaration of Policy at Section 2802(15) of the Act. There, the General Assembly acknowledges the historic obligation of utilities to make substantial investments in facilities or contracts to provide safe and reliable service. The General Assembly recognizes also its obligation to allow recovery of costs stranded by the change the electric generation portion of electric utilities' business from a regulated monopoly to an unregulated competitive service.

31. Claims that this bargain or understanding does not exist deny the facts. Clearly, utility investors relied on prior rules concerning the prudent investment standard and fair rates of return in forming their expectation concerning risks and returns. PP&L St. 1-R, pp. 5-7.

32. The transition to a competitive market for electric generation is a fundamental change in the basic rules by which electric generation services have been provided. Electric utilities must be allowed a fair opportunity to recover investments in facilities made uneconomic by the change in regulatory policy. Any contrary breach of the Commonwealth's obligation to utility investors would be poor public policy, would be contrary to sound economic principles and would be inconsistent with prior law.

33. Under Section 2808(c)(4), in determining the level of stranded costs to be recovered, the Commission is to consider the extent to which the electric utility has mitigated generation-related stranded costs. The Act identifies examples of mitigation steps, and further directs the Commission to consider both mitigation in conjunction with restructuring and pre-restructuring efforts.

34. PP&L's mitigation efforts have reduced its stranded costs. The proof of the effectiveness of PP&L's pre-restructuring mitigation, however, is PP&L's success in controlling its rates, which the Act declares to be of "equal importance" with future efforts to mitigate stranded costs. See 66 Pa.C.S. §2808(c)(5).

35. PP&L's total rates are lower than those of other electric utilities. As shown at pages 16-19 of PP&L St. 9 and in Exhibit SFT 2, PECO's average rate is 9.91¢ per kWh; Duquesne Light Company's average rate is 8.92¢ per kWh. The Pennsylvania statewide average rate is 7.93¢ per kWh. PP&L's average rate of 7.21¢ per kWh is significantly lower than these other rates. In fact, PP&L's rates are now almost as low as the national average of 6.89¢ per kWh, while the spread between Pennsylvania's average rate and the national average rate has stayed relatively constant. PP&L Exhibit SFT 4.

36. PP&L's rates for residential service have dropped below the national average, while Pennsylvania's average residential rate has been well above the national average. PP&L Exhibit SFT 5.

37. In recent years, PP&L has taken advantage of reductions in the cost of capital to refinance higher cost securities. During the 10½ years between its last two rate cases, PP&L reduced its long term debt cost rate by almost 30 percent.

38. PP&L was also able to reduce substantially its cost rate of preferred stock. These capital cost reductions reduced PP&L's revenue requirement in its 1994 base-rate case by $100 million. PP&L St. 2, pp. 6-7.

39. After PP&L's 1985 rate case, PP&L undertook cost containment efforts which resulted in PP&L's operation and maintenance production costs only increasing by 16 percent over 10 years and, adjusted for inflation, have actually declined by 15 percent.

40. From 1985 through 1996, PP&L has reduced its employee complement by 2,005 regular full-time employees, almost 24 percent of its 1985 work force. Most reductions occur through normal attrition, early retirement programs and voluntary severance programs. PP&L St. 2, p. 8.

41. In 1991, PP&L modified its accounting for spare parts at power plants resulting in a pass back of $94 million to customers over 5 years through a rate credit mechanism. PP&L St. 2, pp. 8-9.

42. PP&L also reviewed its spare parts inventories to identify obsolete or excessive items and was able write off off $35 million of inventory, further mitigating PP&L's stranded costs. PP&L St. 2, p. 9.

43. Approximately 62 percent of PP&L's stranded costs relate to the Susquehanna Steam Electric Station, which includes two nuclear generating units PP&L St. 2, pp. 9-11.

44. PP&L was able to complete construction of two large nuclear units at a total cost of approximately $3.6 billion for 1,890 megawatts of capacity or approximately $1,900 per kilowatt. Other plants in Pennsylvania and in the United States, which were constructed contemporaneously with the Susquehanna Units, were completed at significantly higher costs per kilowatt. PP&L St. 2, p. 10.

45. Following completion of Susquehanna, PP&L pursued claims against the containment supplier, General Electric. PP&L settled its claim against General Electric in 1991, and obtained Commission approval to refund the jurisdictional amount of the net settlement proceeds --$55 million-- to customers through a special rate credit mechanism. PP&L St. 2, p. 10.

46. PP&L has operated Susquehanna at a high capacity factor, reducing energy costs and customers' rates. PP&L St. 2, pp. 10-11. More recently, between 1991 and 1995, PP&L spent $45 million to upgrade Susquehanna's capacity by 90 megawatts, or $500 per kilowatt, producing additional energy cost savings for customers.

47. PP&L has operated its fossil fuel generating plants efficiently and has made substantial expenditures to assure the continued viability of low cost, coal-fired generating stations. These generating stations benefit customers through low fuel costs and increased interchange sales, which both lower retail rates. PP&L St. 2, p. 11.

48. PP&L has converted its Martins Creek Units 3 and 4 to gas/oil dual fuel capability. PP&L now can burn gas or oil, whichever costs less, at these Units 3 and 4, which makes them more cost effective. PP&L St. 2, p. 11.

49. Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), PP&L was compelled to enter into long-term supply contracts with Non-utility Generators ("NUGs"). Rates in these agreements were based upon future market prices of fuels, which were projected when contracts were executed. Then, the price of oil was expected by now to be nearing $100 a barrel. PP&L St. 18-R, p. 22. NUG contract prices have turned out to be greater than PP&L's avoided costs of replacement generation or purchased power.

50. PP&L has calculated its stranded costs to be $4.5 billion. PP&L St. 2, p. 18. PP&L has proposed in this proceeding, however, a competitive transition charge ("CTC") that will produce only $4.001 billion, resulting in a shortfall of $500 million. PP&L St. 10-R, p. 3. Under PP&L's proposal, PP&L's shareholders will bear an estimated $500 million of stranded costs.

51. Pursuant to Section 2808(c)(4)(iii), one of the mitigation steps that electric utilities are to consider is reallocating depreciation reserves from transmission and distribution plant accounts to generation accounts. In its filing, PP&L has proposed to transfer $205 million of its depreciation reserve related to transmission and distribution plant to the accumulated reserve for depreciation associated with its Susquehanna Units. The transfer of the depreciation reserve, together with the changes in the reserve for deferred income taxes, would reduce PP&L's stranded costs by $317 million. PP&L St. 2, p. 17.

52. There is no cost shifting between rate classes at the retail jurisdictional level because PP&L's unbundled rates were derived from its cost of service study approved in its 1995 base-rate case, which was not modified to reflect the swap of the depreciation reserve. PP&L St. 3-R, pp. 12-13.

53. PP&L's proposal will not result in cost shifting between federal and state jurisdictions. Any such possible cost shifting will be avoided by PP&L's creation of a regulatory asset applicable to the transmission and distribution functions which equals the allocated depreciation reserve to be transferred. Under this proposal, the net decreased to the depreciation reserve for the Pennsylvania jurisdictional portion of the transmission and distribution function will equal the Pennsylvania jurisdictional portion of the increase to the depreciation reserve for the nuclear generation function.

54. The small change in rates that could result from the depreciation swap will not affect customers' usage patterns. PP&L St. 8-R, p. 53. Further, one purpose of the Act is to achieve lower rates to improve the economy of Pennsylvania. 66 Pa.C.S. § 2802. The Act encourages mitigation of stranded costs for the purpose of reducing electric utilities' CTCs, thereby lowering rates.

55. Customers are protected from overrecovery by electric distribution companies of transmission and distribution costs through the applicable rate cap. The "depreciation swap" is one of the mitigation procedures expressly contemplated in Section 2808(c)(4)(iii) of the Act.

56. In computing stranded costs, PP&L has projected approximately $513 million of unspecified reductions to future operation and maintenance and administrative and general costs. These projections reflect a continued commitment to cost cutting and an estimate of the reductions that PP&L expects to achieve. If PP&L for any reason is unable to achieve the projected $513 million of future cost reductions, PP&L and its investors will bear the costs that PP&L is unable to avoid.

57. In PP&L's most recent base rate case, the Commission approved PP&L's proposal to modify the method by which it accrues depreciation on its Susquehanna Units. PP&L had used a modified sinking fund method in order to moderate rate increases associated with placing these units into rate base. PP&L proposed, commencing January 1, 1999, to switch to a straight line method of depreciation, under which it would experience a reduction in its annual depreciation accrual of an estimated $71 million. In conjunction with its proposal to change the depreciation method, PP&L proposed also to reduce base rates effective January 1, 1999, to reflect the effects of this switch in depreciation method. The Commission approved PP&L's proposal. *Pa. P.U.C. v. PP&L*, Docket No. R-00943271, pp. 106-113 (September 27, 1995).

58. In late 1995, PP&L announced plans to reduce capital expenditures over a 5-year period by $671 million. Of this total, $486 million represented reductions in plant expenditures for fossil generating units. Reductions in capital investment in generating facilities mitigates PP&L's stranded costs. PP&L St. 2, p. 9.

59. Several parties have suggested that stranded costs should be shared between PP&L and its ratepayers by various means. *See, e.g.*, OCA St. 1, pp 29-32; OTS St. 1, pp. 20-21; PPLICA St. 1, pp. 15-22. The parties' proposals that the Commission disallow recovery of a portion of PP&L's stranded costs are based on an incorrect interpretation of Section 2804(13) of the Act which provides:

> Consistent with Section 2808 (relating to competitive transition charges), the commission has the power and duty to approve a competitive transition charge for the recovery of transition or stranded costs it determines to be just and reasonable to recover from ratepayers.

60. The parties "sharing" proposals also are at odds with prior regulatory practice. In previous years, parties in prior utility base-rate proceedings have contended that certain otherwise "just and reasonable" expenses of public utilities should be "shared" between ratepayers and the utility on policy grounds similar to contentions raised by various parties in this proceeding. These contentions have been uniformly rejected by Pennsylvania appellate courts. *See, e.g., Butler Township Water Co. v. Pa. P.U.C.*, 81 Pa. Cmwlth. 40, 473 A.2d 219, 221-22 (1984); *T.W. Phillips Gas & Oil Co. v. Pa. P.U.C.*, 81 Pa. Cmwlth. 205, 474 A.2d 355, 366-67 (1984).

61. The General Assembly has mandated "sharing" mechanisms elsewhere in the Public Utility Code. When considering electric generation units with excess capacity that is not used or useful in the public service or electric generating units which experience excessive outages, the General Assembly has set forth specific procedures for such determinations and specified the specific sharing mechanisms that the Commission is authorized to employ. *See* 66 Pa.C.S. § 1322 (as to excessive outages) and § 1323 (as to excess capacity). In contrast, the Act does not contain any provision requiring a "sharing mechanism."

62. The parties' sharing proposals ignore the fact that virtually all of PP&L's plant investments have been reviewed by the Commission in prior base-rate cases and included in rate base as being prudently-incurred and used or useful in the public service. PP&L's most recent base-rate case was based upon a future test year ended September 30, 1995. *Pa. P.U.C. v. PP&L*, Docket No. R-00943271, p. 1 (September 27, 1995). No generation units have been placed in service since this base-rate case. Only the relatively minor plant additions placed into service since September 30, 1995, could even be the subject of prudence contentions in this proceeding, and no such contentions have been raised. Therefore, all of PP&L's rate base and

PP&L's expenses, as of September 30, 1995, have been determined to be "just and reasonable" as that term is used in Section 1301 of the Public Utility Code, 66 Pa.C.S. A. § 1301, to establish a utility's rates.

63. In the PECO Restructuring case, the Commission ruled that in determining a joint and reasonable level of stranded cost recovery under Section 2808(c)(3), the Commission must consider whether "the utility's efforts to mitigate stranded investment have been "reasonable under all of the circumstances," PECO at 67 (citing Section 2808(c)(4). The Commission noted that Section 2808(c)(4) requires "equal consideration" of the utility's "efforts undertaken over time . . . to reduce or moderate rate levels."

64. OCA's proposal of a 32% rate reduction would produce sharply different results. Under OCA's proposal, PP&L's 1999 *pro forma* return on equity would be a *negative* 9.65%. PP&L would experience an operating loss each and every year of the transition period. PP&L St. 8-R, pp. 24-27.

65. OCA's proposed level of stranded costs is unjustified and does not represent a reasonable even-handed sharing of risks associated with stranded costs.

III. STRANDED COST CALCULATION METHODOLOGY

66. The Act generally identifies three categories of stranded costs: (1) regulatory assets and other deferred charges, the unfunded portion of nuclear plant decommissioning costs, and cost obligations under contracts with non-utility generators ("NUGs"); (2) costs related to the cancellation, buyout, buydown or renegotiation of NUG power supply contracts; and (3) generation-related expenses. 66 Pa.C.S. §2803.

67. PP&L's Restructuring Plan filing includes expenses from each of the categories identified by the Act. Specifically, the Company's filing includes: (1) regulatory assets and other deferred charges typically recoverable under traditional cost-of-service regulation, and cost obligations under Commission-approved contracts with NUGs; (2) prudently-incurred costs related to the cancellation, buyout, buydown or renegotiation of NUG contracts; and (3) net investments and operating expenses associated with existing generation facilities, disposal of spent nuclear fuel, decommissioning costs associated with existing generation facilities, and other stranded costs, including severance, early retirement, outplacement and related costs for employees who are affected by changes anticipated as a result of the transition to full competition under the Act. PP&L St. 8, p. 3.

68. For stranded cost calculation purposes, PP&L divided its claimed expenses into four categories: (1) nuclear generation; (2) fossil generation; (3) NUGs; and (4) generation-related regulatory assets. Utilizing a regulatory or revenue requirement methodology (the "regulatory method"), PP&L determined that it has approximately $4.5 billion in stranded costs after mitigation.

69. The OCA and PPLICA oppose the Company's method of calculating stranded costs related to generating plant, and recommend that the Commission adopt the asset value method proposed by PECO Energy Company in its current Restructuring Plan proceeding (Docket No. R-00973953). OCA St. 1, p. 14; PPLICA St. 2, p. 10. The OCA and PPLICA, however, propose to calculate stranded costs associated with regulatory assets using the regulatory method.

70. The regulatory method of calculating nuclear and fossil generating plant stranded costs compares the annual revenue requirements for each generating plant to the projected annual revenues each plant would receive from the sale of its output using market-based prices for each year beginning January 1, 1999, to the end of its remaining service life. PP&L St. 8, p. 4. The Company then applied a PUC-jurisdictional percentage to the annual excess or deficiency, and discounted the resulting stream of annual excesses or deficiencies to present value at January 1, 1999 using a discount rate of 7.92%, which is PP&L's after-tax weighted average cost of capital. PP&L St. 8, p. 4; PP&L Exh. JRS 1, p. 1.

71. The asset value method compares the present value of revenues, less cash expenses, that could be earned from generating facilities in a competitive market, with the sum of the current book value of generation and

regulatory assets. Cash expenses include any above-market costs that will be incurred under power purchased agreements with NUGs. PP&L St. 8-R, p. 7.

72. Several considerations favor the regulatory method (PP&L St. 8-R, pp. 5-7; PP&L St. 19-R, pp. 15-16):

a. The regulatory method is simple to understand and to apply because it essentially uses a series of future test years, a concept familiar to the Commission. All revenues and expenses are reflected in the time period in which they occur.

b. A variety of conceptual issues arising under the regulatory method -- e.g., the treatment of income taxes -- previously have been resolved by the Commission under traditional cost-of-service regulation. Thus, the regulatory method allows the Commission to apply existing rules and accepted assumptions in calculating stranded costs.

c. The regulatory method is fully consistent with the Act. Specifically, Section 2803 of the Act defines stranded costs as the "known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, *which traditionally would be recoverable* in a competitive generation market and which the commission determines will remain following mitigation by the electric utility." 66 Pa.C.S. §2803. Under traditional rate regulation, utilities are allowed a fair opportunity to recover revenue requirement. Consequently, revenue requirement is the proper starting point for the determination of stranded costs of generating plants. Thus, the Act defines stranded costs based on a comparison of revenue requirements under traditional regulation with revenues projected in a competitive market. The regulatory method properly implements this statutory approach.

d. The regulatory method prevents an electric utility from deriving an unfair benefit from the transition to competition. The regulatory method is designed to ensure that, at most, a utility may only receive the level of revenues that it would have received under current Commission-approved rates.

e. The regulatory method takes into account the effects of book value on revenue requirements year by year. Therefore, the specific complexities and effects of book value, e.g., changing jurisdictional allocation factors and deferred taxes, can be considered fully under the regulatory method. PP&L St. 19-R, p. 15.

73. Application of the asset value approach presents numerous problems and complexities. For example, the asset value method simply cannot be used to calculate the regulatory assets. OCA and PPLICA recognize this shortcoming and purport to use the revenue requirement method for regulatory assets, while retaining the asset value method for plant assets. The result is a mixed, hybrid approach which introduces substantial (and needless) complexities and causes serious errors in the OCA and PPLICA presentations.

74. The Commission's recent Order in the PECO Restructuring proceeding (Docket No. R-00973953) includes a footnote which states as follows (PECO Order, p. 80, note 71):

> We agree with PAIEUG witness Falkenberg that a "lost revenues" approach to stranded cost recovery is inappropriate. He notes that even under traditional regulations, a utility never had the expectation of guaranteed future revenues. Instead, traditional regulation sought to provide a reasonable opportunity to earn a just and reasonable return on investment. While future revenues are an important component of the future value of utility generation assets, they do not directly determine the amount of recoverable stranded utility plant.

75. The PECO Order does not require the use of the asset value method in this case. The regulatory method was not at issue in the PECO Restructuring case. The Commission's brief mention of the regulatory method in the PECO Order is dicta. The OCA and PPLICA stranded cost models are not in the record in this case. Thus, the record evidence simply does not include the information necessary to calculate stranded costs or to make any adjustments to such calculations. In contrast, PP&L's complete regulatory methodology is in the record and is readily available to all parties and the Commission.

76. Application of the asset value model is problematic here because it is not in the record.

77. PP&L's stranded costs should be calculated using the revenue requirements method.

78. Tables B to D to PP&L's M.B. provide a summary of PP&L's $4.5 billion stranded cost claim under the regulatory method. Table B provides the same calculation using the revenue requirements method. Table C provides a summary of OCA's proposal under the asset value method. Finally, Table D provides a reconciliation of the differences between the PP&L and OCA proposals using the asset value method. If the PUC elects to use the asset value method, Table D should be used to derive the value of any adjustments. Changing one item may have secondary effects on other figures which would have to be reconciled in the Company's compliance filing.

IV. MARKET PRICE OF ELECTRICITY

79. The forecast of prospective market prices of electricity is the critical first step in determining the competitive market value of PP&L's generating assets. These electricity prices are used to develop revenues for each plant on an annual basis. The revenues are then used to determine the stranded costs of the generating plants.

80. The prospective market prices for electricity are comprised of two components: The price of capacity and the price of energy. Customers will pay for the right to draw upon PP&L's generating assets when needed. These are payments for capacity. Customers also will pay for electric energy as they use it. These are payments for energy. While both energy and capacity prices are important in evaluating the competitive market value of PP&L's generating assets, energy prices are far more significant because they will represent approximately 90% of revenues received for electricity.

81. Three witnesses in this proceeding have estimated prospective market prices for electricity (S. Jones for PP&L, D. Smith for OCA and R. Falkenberg for PPLICA). Each witness has provided an estimate of future capacity and energy prices.

82. The supply side of the market is the generation sources in PJM and those available to serve customers in PJM. This definition includes both power sources in PJM as well as energy and capacity that can be delivered to PJM. PP&L St. No. 7, p. 9. The demand side of the market for generation includes all customers in PJM as well as those with access to electricity that can be delivered over lines within and connected to PJM. PP&L St. No. 7, p. 9.

83. PP&L estimated future capacity prices by beginning with current contracts for sale of capacity held by PP&L. PP&L currently makes short-term or spot capacity sales and makes sales in the forward market. PP&L St. No. 7, p. 45.

84. In forecasting future capacity prices Dr. Jones projected that capacity prices would rise sharply as PJM moved from the current state of capacity excess to a balance of demand for, and supply of, capacity. This is one of the many effects of a competitive market which must be anticipated in accurately reflecting future market prices. PP&L St. No. 7, p. 45-46.

85. OCA's witness Mr. Smith, projects continually increasing capacity prices from 1999 to 2015. OCA St. No. 2, Ex. No. DCS-7; OCA St. No. 2-S, Ex. No. DCS-10. Mr. Falkenberg, PPLICA's witness, projects generally rising capacity prices with a two year reduction in prices following tightening of the capacity market in 2001. PPLICA St. No. 2-S, Ex. No. RJF-9-b.

86. OCA, PPLICA and OSBA challenged PP&L's forecast of market capacity prices as insufficient to support addition of new capacity. OCA St. No. 2, pp. 12-17; PPLICA St. No. 2, pp. 35-40; OSBA St. No. 1, pp. 32-34.

87. Parties have raised several factors to be considered in evaluating whether capacity prices and energy prices are sufficient to support construction of new capacity. These factors are the cost of the new unit, costs of other facilities such as land and pipelines to serve the unit, and the heat rate (amount of BTUs needed to produce a kWh of electric energy) at which the unit can be expected to operate.

88. PP&L Ex. STJ-28R demonstrates that Dr. Jones projected market prices are sufficient to support the installation of new capacity.

89. The contentions of various parties that Dr. Jones' market capacity prices are "insufficient" to support additions of new capacity are unsupported by the record. PP&L's forecasted prices are sufficient to support such additions at even today's costs and heat rates. As unit costs decrease and/or heat rates improve (less fuel to produce each kWh) the rates of return produced by new units will be even higher. The market capacity prices forecasted by Dr. Jones are demonstrated to be reasonable.

90. The higher capacity and energy prices projected by Messrs. Smith and Falkenberg indicate that investors in new generation will achieve rates of return well in excess of the 13.14% to 13.87% shown in PP&L Ex. STJ-32. Neither witness has provided an explanation why investors will demand capacity prices that will produce returns in excess of 14%. It is not credible to believe that investors will demand capacity prices that will produce returns in excess of 14% in an environment where there are competing projects.

91. Each of the witnesses testifying as to energy prices used a different model to project such prices. Dr. Jones, testifying for PP&L, used the EGEAS (Economic Generation Expansion Analysis System) model. Dr. Jones explained how the EGEAS model operates:

> EGEAS is an economic dispatch model designed primarily for long-term system planning. As its name implies, the primary purpose of the model is to find the best possible combination of generation resources for meeting system load in the short run and in the long run. In the short run, EGEAS is a production cost model, dispatching units to meet demand levels in each hour of the year. Over the long run, the model adds capacity to the existing system to meet reliability constraints. Depending upon the economics at that point in time a new unit will be added, either peaking or combined-cycle technology is added to minimize cost. PP&L St. No. 7, p. 25.

92. The EGEAS model has been used to dispatch units on the PJM system. It is not, therefore, a theoretical model but one which has been tested in the real world environment (Tr 1685-1686). Furthermore, the EGEAS model is publicly available. PP&L St. No. 20-R, pp. 19-21.

93. The model employed by PPLICA's witness, Mr. Falkenberg, is a theoretical model and is proprietary to his firm. (Tr 1676).

94. Mr. Falk identified five areas in which Mr. Falkenberg's model did not optimize costs. They are: 1) maintenance scheduling; 2) scheduling of capacity additions; 3) scheduling of repowering of existing units; 4) calculation of unserved energy, and 5) size of units.

95. These deficiencies cause Mr. Falkenberg's model to overstate market prices and understate stranded costs.

96. Mr. Falkenberg's model has not been tested in the real world of energy dispatch and is a proprietary model that was not made available to even the parties in this proceeding until after the filing of rebuttal. The over simplifications and the lack of independent real world application of the model make it unreliable for the purposes of forecasting market prices.

97. OCA's witness, D. Smith, used the ENPRO model to forecast energy prices. This model is less problematic than the Falkenberg model for two reasons. First, it is an operational dispatch model like EGEAS, not a theoretical model like the Falkenberg model. Second, ENPRO is commercially available, and, therefore can be obtained and run by any participant in this proceeding.

98. The primary deficiency of the ENPRO model is that it can model only 200 units (Tr 1398). In order to provide room for the addition of new units, Mr. Smith could model less than 200 of the 350 existing units in PJM (Tr 1398, 1511). To accomplish this, Mr. Smith had to aggregate existing units or treat them as one unit (Tr 1511). The problem with aggregating units is that it raises energy prices by using the average cost of the aggregate group rather than the lowest cost at all times.

99. A second deficiency is in Mr. Smith's application of ENPRO. As explained by Dr. Jones, Mr. Smith simply assumes that units which can be fired with either oil or gas will use oil one half of the time and gas the other half of the time, regardless of competing fuel prices. This is a problem, particularly where oil prices, as in Mr. Smith's fuel price forecast, rise faster than gas prices. This assumption is unrealistic and biases electricity prices upward since dual fuel units can be presumed to use the lower price fuel (Tr 1397-1398).

100. Finally, Mr. Smith reduces the availability of imports from outside PJM after 2005, without explanation or justification. (Tr. 1398). Because imports from the west generally are at lower costs (Tr 1510) this increases the price of electricity in PJM just as the 7-year rate cap under the Act expires.

101. The EGEAS model, in contrast, does not contain the methodological problems identified by PP&L with regard to the Falkenberg model and ENPRO. Specifically, EGEAS is a dispatch model which has been used for many years in dispatching units on the PJM system.

102. The EGEAS model can model all of the units in PJM as well as necessary additions, it schedules maintenance rather than spreading it arbitrarily throughout the non-summer months, it optimizes new capacity additions to produce the lowest energy costs by choosing between combustion turbine and combined cycle units, it uses appropriate prices for unserved energy and it properly reflects different summer and winter capacity ratings. PP&L St. No. 20-R, p. 18. It reflects actual conditions on PJM.

103. The main criticism which other parties have directed at the use of the EGEAS model concerns the treatment of start up or no load costs.

104. Either the EGEAS model or the ENPRO model, with certain corrections, can be used to forecast energy prices. The correct inputs to the model are, by far, the most critical issues in forecasting energy prices and

differences in the inputs selected by each witness account for the majority of the differences between the forecasts of the witnesses.

105. Perhaps the most critical and significant input to the models is the cost of fuel to operate each unit that generates electricity. Since the energy price for all units running in a given hour equals the cost of operating the marginal cost unit operating in that hour, the variable cost of operating the marginal cost unit is critical. Fuel price is the primary component of variable cost.

106. A forecast of fuel prices must reflect the fundamentals of fuel markets. In particular, two concepts are extremely important. The first concept is that increases in fuel prices should be separated into two components: increases in *real* fuel prices (exclusive of inflation) and increases in fuel prices due to inflation. The combination of the increase in the real fuel price and the effect of inflation on the fuel price produces the nominal fuel price at any point in time.

107. The second concept is that projected increases in one fuel price, such as natural gas, must be reviewed in the context of competing fuels such as oil and coal. Both common sense and experience demonstrate that prices of competing fuels move in tandem and forecasts which project different rates of increase for competing fuels are highly suspect.

108. 1996 real fuel prices would remain flat until 1999. Dr. Jones then forecasted that real fuel prices would remain flat and would increase by the increase in inflation from 1999 forward. PP&L St. No. 7-R, p. 41.

109. Dr. Jones projected that real fuel prices would remain flat after 1999 because history demonstrates that real fuel prices rise and fall but revert to a mean price of about $15.50 in 1996 dollars over the long term. PP&L St. No. 7-R, p. 47. As shown in Dr. Jones' Ex. No. STJ-16, oil prices averaged about $15.50 a barrel (in 1996 dollars) over the period 1900 to 1996 excluding the unusual period of 1979 to 1985 represented by the Iranian Revolution. Nevertheless, Dr. Jones adopted a real oil price of $18.00 per barrel (Ex. No. STJ-16), which corresponds to the average price of $17.90/Bbl over the last 10 years. PP&L St. No. 7-R, p. 54.

110. Only Mr. Knecht, on behalf of OSBA, attempted to refute Dr. Jones' explanation that real prices are mean reverting, by calculating a .8% rate of increase in the price of oil from 1939 to 1996. OSBA St. No. 51, pp. 17-22, Ex. No. RDK-S-2. However, Dr. Jones explained in rejoinder that the choice of a particular starting year substantially effects this type of calculation. If Mr. Knecht had chosen any of 24 differing starting points since 1900 there would have been real declines in oil prices and, if many other starting years were used, real oil prices would simply be flat (Tr 1404-1405). As a result, choosing a starting point year near the end of a depression when oil prices were low fails to provide any useful information about the long term trend of real oil prices.

111. Projections of rising real fuel prices are contrary to both the weight of historic evidence and the progress of technological developments in exploration for fuels (Tr. 1405-1406).

112. Messrs. Falkenberg (PPLICA) and Smith (OCA) rely on the forecasts prepared by DRI and EIA respectively. By increasing nominal fuel prices more than their projected increases in inflation, these forecasts effectively project both increases in real fuel prices and increases in fuel prices due to inflation. PP&L St. No. 7-R, p. 55; Tr 1404.

113. Neither witness has presented any substantive basis for concluding that real fuel prices will rise. In this regard, it is to be noted that the real oil price of $18.00/Bbl is essentially equal to the $17.90/Bbl average price over the last 10 years and is significantly above the $15.50/Bbl average long-term price of oil in 1996 dollars excluding years affected by the Iranian Revolution. PP&L St. No. 7-R, p. 54.

114. As shown on PP&L Ex. STJ-18, one standard deviation around this average price establishes a range of $12/Bbl to $19/Bbl. While oil prices may rise and fall above the average it is reasonable to conclude that they only rarely will move outside one standard deviation. As also shown on PP&L Exhibit STJ-18, in contrast to Dr. Jones' real oil price of $18/Bbl, Mr. Falkenberg's (EIA's) real oil prices begins at about

$19/Bbl and continually rises throughout the forecast period to prices of about $24/Bbl, well outside one standard deviation from the average price. The DRI forecast used by OCA produces similar results (Ex. No. STJ-19). Accordingly, the expectation of these forecasts -- that real oil prices will rise -- is not supportable given historic trends.

115. The witnesses' use of the DRI and EIA fuel prices is inappropriate given that both entities have continually over-estimated fuel prices. As shown on PP&L Ex. STJ-14a and 14b, each of EIA's 1986, 1987, 1989 and 1992 long term fuel price forecasts has consistently overstated fuel prices. DRI's fuel price forecasts closely matches EIA's over-estimates (Ex. STJ-19). As shown on PP&L Exhibit STJ-35, DRI's 1994 and 1995 forecasts also overstated inflation and, thereby fuel prices.

116. As shown in PP&L Ex. STJ-21, the DRI 96 forecast begins with average inflation rates of 2.3 for 1997-2000, but then increases inflation rates to a level of 3.5%, on average, for the period 2005-2015. OCA's Mr. Smith revised his forecast to reflect the updated DRI Spring 1997 Outlook (Tr. 1516-1517) and to correct a "starting point" problem Dr. Jones noted in his testimony (Ex. STJ-12). Even so, the updated Spring 1997 Outlook continues to use the much higher 3.5% average annual inflation rate for the period 2005-2010.

117. Mr. Falkenberg used the EIA forecast for 1997. As also shown in PP&L Exhibit STJ-21, the EIA forecast starts with inflation at 2.5% and raises it to 3.4 % on average for 2005-2010 and 3.6% on average for the period 2010-2015. As shown on PP&L Exhibit STJ-35, DRI has consistently over-estimated inflation in past forecasts. EIA forecasts match DRI's forecasts closely (Ex. STJ-19).

118. Neither Mr. Smith nor Mr. Falkenberg has offered any explanation why the inflation rates built into the DRI and EIA fuel forecasts escalate over time (Tr 1403). These inflation forecasts are from the DRI and EIA fuel price forecasts. Despite reliance on these forecasts neither witness even obtained the full source documents for these forecasts or analyzed the bases used in these forecasts to estimate inflation (Tr 1517-1518, Tr 1750). Accordingly, they have not examined the bases for these forecasts. Forecasts of inflation which rise over time are simply inconsistent with federal reserve policies observed over the last decade (Tr 1400). There is no basis, on this record, to justify the use of the EIA and DRI inflation estimates and the record demonstrates that their forecasts have consistently overstated inflation.

119. The rising rates of inflation combined with rising real oil prices projected by these parties create what Dr. Jones referred to as the "dog leg" problem. The DRI and EIA forecasts initially project gradual rises in fuel prices but as the higher inflation rates and increases in real fuel prices "kick in," nominal fuel prices rise sharply. As shown graphically in PP&L Ex. Nos. STJ 14a and b, the fuel price curve slopes upward in the shape of a dog leg. There is no precedent in history for such an effect (PP&L St. No. 7-R, p. 42) and, in past forecasts, this phenomenon accounts, in part, for DRI's and EIA's confirmed over-forecast of fuel prices (PP&L Ex. No. STJ-14a and b).

120. In addition to the errors of improperly rising real fuel prices and increasing inflation rates, the EIA and DRI forecasts project a divergence between the real prices of oil and gas versus the real price of coal.

121. The divergence of gas and oil prices from coal and uranium prices is both illogical and unprecedented for competing fuels. As demonstrated by Dr. Jones in Ex. STJ-16a, real prices of competing fuels are highly correlated over the 15 year period of 1981-1995. In other words, the prices of these fuels move up and down together. If the price of one competing fuel rose sharply and others did not move upward, there would be fuel switching in many applications (PP&L St. No. 7-R, pp. 47-49). This is particularly the case for gas and oil versus coal. As also shown in PP&L Ex. No. STJ-16a, Dr. Jones's forecasts of the prices of each type of fuel are highly correlated. On the other hand, the fuel price projections of DRI and EIA show a significant, and historically unprecedented, divergence of oil and gas prices from the price of coal.

122. The "divergence" problem is particularly critical to the issues of stranded costs in this proceeding. The marginal cost units operating on PJM will normally be gas and oil fuel units, and these units will set the price for all units operating in the same hour. OCA and PPLICA understate the costs of operating PP&L's

coal generating units by assuming coal prices that are inconsistent with oil and gas prices used in their models. The result is an understatement of stranded costs associated with these units.

123. Even if the DRI gas and oil prices were accepted, the Commission must, at a minimum, adjust upward the coal prices assumed by DRI. To do otherwise is not only contrary to the record but would punish PP&L for owning and operating coal plants that have produced low cost electricity for many years.

124. PP&L has submitted a recalculation of its stranded costs which, among other things, uses prices for coal that escalate in a manner that is consistent with DRI's escalation of oil and gas prices. Correction of this divergence problem alone would create an increase in stranded costs of approximately $230.157 million.

125. The evidence shows that the DRI and EIA fuel price forecasts are overstated. These overstated fuel prices result in a significant overstatement of energy prices forecasted in Mr. Smith's (OCA) ENPRO model and Mr. Falkenberg's (PPLICA) model.

126. The forecast of inflation is significant because it affects fuel prices and because inflation is used to escalate other costs that are used in each of the models to derive market prices of electricity. In particular, variable O&M costs must be projected for each of the units that will be operated. Each of the witnesses applies an expected inflation rate to current levels of variable O&M costs to derive future O&M costs.

127. There are two issues with regard to the projection of inflation. The first is what measure of inflation should be used. The second is the year by year amount of inflation.

128. With regard to the proper measure of inflation, Dr. Jones explained that the Consumer Price Index (CPI) is clearly overstated as to costs faced by PP&L because it relates to consumer products and not to items that affect PP&L's generating costs. While the Gross Domestic Product (GDP) deflator is a better indicator of the effect of inflation on such costs, this measure includes long-lived assets as if they were purchased monthly. Dr. Jones, therefore, concluded that the Producer Price Index (PPI), which measures prices received by industrial firms for goods they produce is the best indicator of costs to be incurred by PP&L. PP&L St. No. 7-R, pp. 60-61. Dr. Jones estimated average future inflation at 2.5%. PP&L St. No. 7, p. 40, PP&L St. No. 7-R, p. 61.

129. OCA's and PPLICA's witnesses did not evaluate the proper measure of inflation or attempt to estimate inflation. OCA and PPLICA simply adopted the rising inflation rates contained in the DRI and EIA forecasts (Tr 1401-1402). OCA and PPLICA can not explain the basis for these increasing inflation estimates because they merely accepted the numbers in the fuel price forecasts.

130. The OCA's and PPLICA's continually rising inflation assumption is completely inconsistent with federal monetary policy and the projections of other professional forecasters (Tr. 1400-1401).

131. PP&L's proposed steady 2.5% inflation rate is consistent with current experience and modern monetary policy, and provides a reasonable inflation projection for use in this proceeding.

132. PP&L forecasted electricity demand for PJM by adopting the most recent forecast of demand compiled by PJM. Updates for demand on PP&L's system through December 1996 were reflected. PP&L St. No. 7, p. 44. PP&L estimated demand growth of about 1.5% annually. No party has raised any issue with regard to forecasted demand.

133. The efficiency of new units also effects energy prices. In the EGEAS model, Dr. Jones made a very conservative estimate of the fuel consumption of new combined cycle and combustion turbine units. He assumed that a combined cycle unit would require 7000 BTUs of energy to produce a kWh and that a combustion turbine would require 10,200 BTUs to produce a kWh (Ex. No. STJ-5). These assumptions are conservative. For example, many existing combined cycle units already can produce one kWh at lower BTU levels (*i.e.* lower heat rates) (STJ-28R). Reflection of these lower actual heat rates in EGEAS would have resulted in lower energy prices and higher stranded costs because it would take less fuel to produce

each kWh of energy from new units. No party has challenged the reasonableness of the efficiency assumptions used in EGEAS to project energy prices (Tr 1392).

134. Nuclear capacity factor refers to the percentage of the time that base load nuclear units will be operating. The use of a nuclear capacity factor that is too low in the models raises marginal energy prices by requiring other units with higher variable costs to operate. If actual nuclear capacity factors turn out to be higher than reflected in the models, actual energy costs will be lower than projected by the models.

135. Dr. Jones employed a forecasted 78% nuclear capacity factor in the EGEAS model based upon a study of actual unit availability factors in PJM and other systems. PP&L St. No. 7, p. 30. The data used to calculate availability is provided in Ex. STJ-6.

136. Mr. Smith used a 75% annual capacity factor. OCA St. No. 2, p. 21.

137. The availability of nuclear units has been steadily increasing and is projected to increase further. PP&L Exhibit STJ-30 shows historical availability factors for nuclear units in the United States from 1982 to 1995. In that period, the availability factor has improved steadily from about 65 percent to nearly 80 percent. Mounting experience in operating nuclear units has led to better management practices and fewer forced outages. Moreover, NERC forecasts show that this trend is expected to continue. PP&L Exhibit STJ-30 plots forecasted capacity factors to 2006 (actual capacity data are shown from 1991 to 1996). NERC forecasts suggest availability factors of at least 85 percent should be expected for the next decade. Thus, 78 percent is a somewhat conservative estimate of future nuclear availability. . PP&L St. No. 7-R, pp. 106-107.

138. The record fully supports a 78% nuclear capacity factor recommended by Dr. Jones.

139. Another element in projecting generating costs is the variable Operation and Maintenance expenses (O&M) of each unit. Variable O&M expenses are those associated with the production of energy as contrasted with fixed O&M which are costs associated with maintaining plants ready to operate.

140. Dr. Jones forecasted variable O&M expenses by escalating current variable O&M costs for each plant. Dr. Jones explained that the experience in industries that have moved from regulation to competition is that O&M expenses increase, for a period of time, at rates that are less than the rate of inflation. For this reason, Dr. Jones selected escalation rates for variable O&M expenses of 2% for 1997-2000, 1.5% for 2001-2005 and 2.5% for 2006-2016 (Ex. STJ-4).

141. Dr. Jones explained that his projection is based on an examination of the trends in O&M costs in capital intensive industries beginning with the 1980's, a review of the recent restructuring that has taken place in the natural gas pipeline industry, and evidence and opinion from various industry and academic publications. All of this evidence suggests that variable O&M costs in parts of the industry may by rising slower than inflation for some time. PP&L St. No. 7, pp. 41-42.

142. OCA's and PPLICA's witnesses simply applied the inflation forecasts contained in the DRI and EIA fuel price forecasts to current levels of variable O&M costs.

143. There are two problems with the OCA's and PPLICA's approach. First, DRI and EIA have consistently overestimated inflation. OCA's and PPLICA's witnesses provide no explanation or justification for these groups continual, and never realized, projections of rising inflation. Second, neither witness has reflected the probable effects of competition on variable O&M costs. As explained by Dr. Jones and further illustrated in his rebuttal testimony (PP&L St. 7-R, pp. 22-25; Ex. No. STJ-9), competition in the rail, trucking, airline and natural gas industries has produced ". . . double digit decreases in prices and costs of production . . ." St. No. 7-R, p. 24.

144. Dr. Jones' projections of variable O&M costs are both reasonable and conservative in that they likely overstate costs given the proven effects of introducing competition in other industries.

145. Reserve requirements refer to the amount of capacity which is required above expected demand to serve unexpected contingencies such as an unplanned outage of a generating station.

146. PJM currently plans for a 20% reserve requirement. PP&L St. No. 7, p. 23. However, Dr. Jones concluded that competitive pressures will lower reserve requirements to 18%. PP&L St. No. 7, p. 24. Mr. Smith also assumed a going forward reserve requirement of 18% although he indicated that this might not be achieved by 2000. OCA St. No. 2, p. 18. PPLICA's witness did not address reserve requirements.

147. Reserve requirements affect energy prices by determining the timing of additions of new capacity. As new capacity is added marginal energy prices will generally decline because the new capacity is more efficient (less fuel or BTUs to produce each kWh). Thus, higher reserve requirements mean lower energy prices. Therefore, Dr. Jones' adoption of an 18% reserve requirement, as compared to the current 20%, increases energy prices and lowers stranded costs. If Dr. Jones had continued to employ a 20% requirement, it would have forced the model to add new efficient additions at an earlier date and energy prices would have been lowered. Accordingly, the 18% reserve requirement is conservative and properly and consistently reflects the future effects of competition.

148. In projecting energy prices it also is necessary to include certain environmental costs which will affect the cost of operating the marginal cost generating unit. As explained by Dr. Jones, the EGEAS model permits the input of costs of emission allowances as an adjustment to fuel price escalators.

149. Dr. Jones explained how EGEAS models SO_2 emission allowance as follows:

> The first step is to identify which units will be running when the region is not in compliance. EGEAS accomplishes this by checking the emission production rate against the annual emission limit input for each facility. Once the units are identified, then those units that are subject to emissions limits are assigned allowances sufficient to bring them into compliance. The cost of bringing those units into compliance is built into the fuel escalation rates for PJM. PP&L St. No. 7, p. 42.

150. To determine the emission allowances Dr. Jones reviewed the history of SO_2 allowance prices, which have steadily declined, and he reviewed forecasts of allowance prices. Dr. Jones adopted the ICF Kaiser low case estimates of allowance prices through 2000 and escalated those allowances by the 2.5% expected inflation rate which he applied to escalate other costs. PP&L St. No. 7, pp. 41-42.

151. Dr. Jones did not include NO_x allowances as a cost in developing energy prices because of the great uncertainties in the development of technology to reduce NO_x emissions, uncertainties as to the levels of controls required for NO_x, the fact that NO_x controls are applied only in the ozone period of May through September and the lack of a developed market for NO_x allowances. PP&L St. No. 7, pp. 43-44; PP&L St. No. 7-R, pp. 97-104.

152. OCA's witness, D. Smith, contended that NO_x emission allowances will increase energy prices by something less than \$1/Mwh. He also argued that NO_x allowances would have a significant effect on PP&L's net revenues (OCA St. No. 2, p. 24) but he did not quantify such effect.

153. In rebuttal, Dr. Jones explained the history of declining SO_2 allowance prices and that the competitive market would similarly drive down NO_x compliance costs. Dr. Jones concluded that electricity prices would rise from about \$.05/Mwh to \$.30/Mwh as a result of NO_x emissions with the higher end of the range being experienced late in the transition period when NO_x standards tighten. Therefore, the combination of a minor price effect occurring late in the transition period has a very small effect due to the present value impact. PP&L St. No. 7-R, p. 102.

154. No party responded to Dr. Jones' rebuttal on NO_x emission costs. The evidence demonstrates that NO_x emission costs are not a relevant factor.

155. An additional input to energy price models is the output of Non Utility Generators (NUGs). There is a dispute among the parties concerning the capacity factor at which these units will operate. Dr. Jones used a 90% capacity factor based upon actual historic experience provided by Mr. Krall within PP&L's service territory. PP&L St. No. 7-R, p. 105.

156. OCA witness La Capra argues that PP&L has overstated NUG output by 10-15%. OCA St. No. 1, p. 10. However, as explained in Mr. Krall's rebuttal testimony, the NUG capacity factors used were those actually experienced for the 3-years 1994-1996 on PP&L's system. As Mr. Krall also explained, most NUGs have now been on line for some time and early operation and start up issues have been resolved. Because there are strong incentives for high output created by payments on the basis of kWh output, these units are, and will remain, well maintained.

157. Based on the record evidence, it is reasonable to conclude that future output levels will equal or exceed recent historic levels. PP&L St. No. 10-R, p. 40. OCA has provided no reasonable basis to reject use of these actual capacity factors for NUGs.

158. Another element which was considered by Dr. Jones in forecasting the market price of energy is ancillary services. As Dr. Jones explained, the only ancillary service that affects the market price of energy is spinning reserves.

159. Dr. Jones explained that spinning reserves were reflected in the EGEAS model. . PP&L St. 7-R, p. 90. By including the spinning reserve units as units dispatched, EGEAS includes the effects of a spinning reserve requirement in its determination of hourly energy prices.

160. The revenues received from spinning reserve operators are likely to cover only the variable costs (start up and no load costs). Accordingly, such revenues will not reduce PP&L's stranded costs of generation because they will recover only variable costs and can contribute nothing toward recovery of fixed costs. PP&L St. No. 7-R, p. 89.

161. Although there are potentially other sources of revenues from ancillary services, these revenues will not affect market clearing prices for energy. Furthermore, the amounts of these revenues are not significant. As noted by Dr. Jones, revenues derived from payments for non-spinning reserves should be very small given the large amount of capacity on PJM and the relatively small non-spinning reserve requirement. PP&L St. No. 7-R, p. 91. Similarly, frequency and voltage regulation will be provided at cost and would produce no contribution to fixed or stranded costs. PP&L St. No. 7-R, p. 92.

162. Dr. Jones demonstrated in rebuttal that the effects of ancillary services on market clearing energy prices have been properly reflected in the EGEAS model. OCA provided no response in surrebuttal. Therefore, there is no remaining issue.

163. One other issue raised by other parties concerns the effects on market clearing energy prices that would be created if there were an earlier than expected retirement of a generating plant.

164. Dr. Jones used projected retirement dates provided by Mr. Krall in PP&L St. No. 3-R. These dates reflect the retirement dates reflected in PP&L's last base-rate proceeding and are the dates reflected in PP&L's current depreciation rates. PP&L St. No. 7-R, p. 87.

165. OSBA's witness Mr. Knecht (OSBA St. No. 1, p. 30-31) and OCA's witness D. Smith (OCA St. No. 2, p. 19) argued that economic conditions could cause earlier retirements and that early retirements would raise energy prices.

166. Dr. Jones explained that Messrs. Knecht and Smith are incorrect because new, efficient CC units will tend to displace existing less efficient fossil units. This transition will lower rather than raise energy prices. PP&L St. 7-R, pp. 86-87.

167. PP&L also notes that Mr. Smith s application of ENPRO assumes that all plants will remain in service throughout the projection period. This neither reflects PP&L's projected retirements nor the proposal of OCA witness La Capra that the Commission should use PECO's projection of revised retirement dates of the Keystone and Conemaugh stations.

168. Dr. Jones' use of PP&L's current projected retirement dates as used in PP&L's last rate case is appropriate and conservative. Retirements dates of other PJM units is similarly supported. However, if these older plants are retired earlier than expected, the record supports the conclusion that Dr. Jones' energy prices are overstated with a resulting understatement of PP&L's stranded costs.

169. Dr. Jones' forecasted energy and capacity prices provide a consistent and reasonable basis to determine PP&L's stranded costs of generation. The record in this proceeding demonstrates that the EGEAS model is the most realistic and reliable model for projecting energy prices. While numerous issues have been raised by various parties concerning the appropriate inputs to the model, the record demonstrates that inputs selected by Dr. Jones are consistent and properly reflect expectations in a competitive market.

V. REVENUE UNDER REGULATION

170. In developing its PUC-jurisdictional allocation ratios, PP&L began with the cost allocation study presented in PP&L Exhibit JMK 1. That study complies fully with the Commission's Final Order in PP&L's most recent base rate case at Docket No. R-00943271, and forms the basis for existing retail customer tariff rates. PP&L St. 3-R, p. 13. The applicable ratios shown in PP&L Exhibit JMK 1 were then adjusted for known and measurable changes to PP&L's existing wholesale bulk power contracts, its contract with UGI Utilities, Inc. - Electric Division (a partial requirements wholesale customer), and its full requirements contracts with wholesale municipal customers, including Citizens' Electric Company and Allegheny Electric Cooperative, Inc. The adjusted PUC-jurisdictional allocation ratios used to determine PP&L's overall level of stranded costs are shown in PP&L Exhibit JRS 1.

171. OCA witness LaCapra recommends that the Commission reject these changes and utilize instead, without modification, the PUC jurisdictional allocation factors approved by the Commission in PP&L's most recent base rate proceeding. OCA St. 1, p. 9. Mr. LaCapra argues: (1) it is inconsistent with prior Commission practice; (2) the changes are "speculative"; and (3) the projected costs could be allocated to wholesale, not retail, customers. *Id.*[3]

172. As explained by Mr. Krall, all Pennsylvania electric utilities, including PP&L, are required to demonstrate on an annual basis that they have adequate generating resources to meet the needs of their customers over a ten-year planning horizon. PP&L St. 10-R, p. 29. If PP&L failed to meet this requirement, it would have had to obtain the necessary resources either through a new generating facility or a power purchase agreement. *Id.*

173. In PP&L's case, the evidence plainly demonstrates that the Company will need additional capacity to meet future load growth. PP&L St. 10-R, pp. 30-31.

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3 Mr. La Capra's adjustment impacts each element of stranded costs. As shown on Table D, the net effect is to reduce stranded costs by $388.415 million. Environmentalist witness Schoengold argues that the proposed increasing retail allocation factor "has the effect of causing retail customers to subsidize PP&L's wholesale business." Environmentalists St. 1, p. 18. To address this alleged problem, Mr. Schoengold recommends that the Commission utilize a single, fixed allocation favor of 80% to determine the PUC-jurisdictional portion of each component of stranded costs. *Id.*

174. The capacity returning as a result of PP&L's expiring power supply contracts is needed to address its projected capacity deficiency and to maintain adequate reserves for reliability.

175. Even with this returning capacity, the evidence demonstrates that the Company's reserve levels will fall toward the low end of the Commission's acceptable range at the end of the 10-year planning period. PP&L St. 10-R, p. 32.

176. The parties' proposed adjustments to PP&L's jurisdictional allocators are inappropriate. The subject capacity is needed to adequately meet the needs of the Company's customers in the future.

177. Under traditional cost-of-service rate regulation, PP&L is entitled to an opportunity to earn a fair rate of return on its investment in facilities and assets dedicated to the service of the general public. Thus, in calculating the overall level of its stranded costs, PP&L appropriately included a return of and return on its unrecovered investments. The cost of equity is also relevant in determining the appropriate discount rate to be used in this proceeding.

178. The table below summarizes the Company's position regarding the rate of return that should be utilized to calculate stranded costs in this proceeding. The capital structure ratios and cost of long-term debt and preferred stock are the levels as of December 31, 1996, the end of the historic base period in this case.

	Balance Dec. 31, 1996	(1) Ratio	(2) Cost of Capital	(1) x (2) Weighted Cost of Capital	After Tax Rate
Long-term debt	$2,744,256	47.0%	7.89%	3.71%	2.17%
Preferred stock	454,911	7.8%	7.10%	0.55%	0.55%
Common equity	2,637,839	45.2%	11.50%*	5.20%	5.20%
	$5,837,006	100.0%		9.46%	7.92%

* Rate of return on common equity granted by the Commission in its Final Order at Docket No. R-00943271.

179. PP&L has reflected an 11.5% rate of return on common equity in its Restructuring Plan filing. PP&L St. 6, p. 2. The 11.5% rate of return is equal to the rate of return adopted by the Commission in its Final Order in PP&L's most recent base rate case at Docket No. R-00943271 (Order entered September 27, 1995). PP&L argues that an 11.5% rate of return on common equity is both reasonable and very conservative, as shown by the independent analysis performed by Mr. Paul R. Moul. PP&L's proposed 11.5% rate of return is 125 basis points *less* than the 12.75% rate of return recommended by Mr. Moul. PP&L St. 6, p. 2.

180. The cost of common equity does not lend itself to precise mathematical calculation. The computation necessarily requires the use of overly restrictive and, in certain respects, unrealistic assumptions. Thus, the use of more than one approach provides a range of results which adds reliability to Mr. Moul's analysis and better reflects the range of factors that motivate investors to commit capital to an enterprise. PP&L St. 6-R, p. 2.

181. As a check on the reasonableness of his primary results, Mr. Moul also analyzed the cost of equity for a Barometer Group. The Barometer Group consists of eight electric companies with risk characteristics similar to those of PP&L. PP&L St. 6, pp. 2-3.

182. Based on these results, Mr. Moul determined that the appropriate cost of common equity is at least 12.75%. PP&L St. 6, p. 3. On this basis, Mr. Moul concluded that the 11.5% rate of return on common equity reflected in PP&L's Restructuring Plan filing "is below that indicated by the market models." PP&L St. 6, p. 3. Moreover, this rate of return likely will underestimate the cost of equity over the next thirty years because it is based on a 1996 base period, during which interest rates were relatively low by historical

standards. PP&L St. 6, p. 4. Mr. Moul subsequently updated his analysis to reflect market data through May 1997. PP&L St. 6-R, p. 3. This analysis confirmed Mr. Moul's 12.75% cost of equity recommendation. PP&L St. 6-R, p. 3.

183. OTS witness Mr. Deardorff recommends an alternative cost of equity allowance of 10.25% in this proceeding.[4] OTS St. SR-3, p. 2. Mr. Deardorff's recommendation is solely based on his application of the DCF model to PP&L and to a barometer group of thirteen electric companies. OTS St. 3, pp. 8-10.

184. Mr. Deardorff's proposed rate of return on common equity would produce earnings per share of only $1.77. PP&L St. 6-R, p. 6. This earnings level is lower than PP&L's earnings per share in any year since 1988 (with the exception of 1994 when several unusual occurrences artificially depressed earnings), and is significantly below the earnings per share of $2.00 to $2.10 forecasted for PP&L by Value Line. PP&L St. 6-R, p. 6.

185. Similarly, Mr. Deardorff's recommendation would fail to produce the necessary pre-tax interest coverage. Specifically, Mr. Deardorff's proposal will only result in 3.44 times pre-tax interest coverage. The Company's pre-tax interest coverage must be above the 3.5 times threshold for the A rating for an electric utility with an average business position. The Company's proposed 9.46% overall rate of return will meet this requirement because it will provide 3.65 times pre-tax interest coverage and thus will provide PP&L with reasonable credit quality to attract capital investment. PP&L St. 6-R, p. 8.

186. Mr. Deardorff's proposed 10.25% cost of equity allowance is inappropriate as it understates PP&L's cost of capital.

187. Mr. Gruber recommends that the Commission adopt a 6.6% return on common equity in calculating the WACC. In Mr. Gruber's view, the return on common equity should be reduced to reflect his belief that "the risk faced by the Company in recovering its stranded cost is near zero . . . ." OTS St. 1, p. 10. The OTS' proposed adjustment would result in a 7.25% pre-tax WACC and a 5.71% after-tax WACC, and would reduce PP&L's stranded cost claim to $3,671,499,000. OTS St. 1, p. 11.

188. Mr. Gruber's recommendation confuses the cost of common equity relevant to a calculation of PP&L's stranded costs on the one hand, with the carrying charge applicable to the CTC and the recovery of such stranded costs on the other. The Act defines stranded costs as costs that would have been recovered in a traditional regulatory environment *prior to the existence of a CTC.* 66 Pa.C.S. § 2804. Under traditional rate regulation, an accurate determination of a PP&L's revenue requirement requires that, at a minimum, the WACC reflect the Company's cost of common equity.

189. The record evidence shows that PP&L in fact faces significant risk in recovering its full stranded costs. This risk is attributable to: (1) the rate cap that will limit the Company's total charges to customers during the CTC collection period; (2) the many assumptions that necessarily were used to calculate the stranded costs upon which the CTC is based; (3) the lack of any true-up under the Act of actual costs against the estimated costs used to calculate stranded costs; (4) PP&L's estimated cost of capital at December 31, 1996, which may not reflect actual capital costs during the period 1999 to 2005; and (5) the Company's use of a lower rate of return on common equity than that required by investors. PP&L St. 6-R, p. 24. Each of these factors increases the risk that PP&L will not fully recover its stranded costs.

190. The effect of Mr. Gruber's proposal is shown in PP&L Exhibit LAG 6. As noted in that exhibit, Mr. Gruber's risk-adjusted cost of equity results in an after-tax WACC of 5.71%, which is 72.1% of PP&L's proposed 7.92% after-tax WACC. Similarly, Mr. Gruber's risk-adjusted after-tax WACC effectively reduces PP&L's relevant book value by 26.3%, which is roughly the same percent reduction recommended

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4 Mr. Deardorff originally recommended a cost of equity of 10.50%. OTS St. 3, p. 6. Mr. Deardorff revised his initial recommendation on surrebuttal "to account for changes that have occurred in both analysts' growth forecasts and market data and to correct a computer programming error." OTS St. SR-3, p. 2.

by Mr. Gruber for the Company's proposed after-tax WACC. PP&L St. 19-R, p. 26. Mr. Gruber's proposal fails to accurately determine the full measure of PP&L's stranded costs.

191. OCA witness La Capra recommends that the Commission utilize a 10% rate of return on common equity in lieu of the PP&L's cost of equity of 11.5% in calculating the appropriate discount rate to be applied in this case. Mr. La Capra's recommendation is based on the 10% return on common equity approved by the Commission in PECO Energy Company's Qualified Rate Order proceeding at Docket No. R-00973877. OCA St. 1, p. 8. The effect of Mr. La Capra's proposal is to reduce the overall level of PP&L's stranded costs by approximately $135 million. PP&L St. 19-R, p. 30-31.

192. There is no support for Mr. La Capra's proposal to use a lower cost of common equity in calculating the overall level of PP&L's stranded costs. Indeed, Mr. La Capra conceded in cross-examination that there is no evidentiary support for his proposal since he had not conduced a cost of equity analysis to support his recommendation. Tr. 1778-1779.

193. The Company's proposed cost rates for long-term debt and preferred stock are 7.89% and 7.10%, respectively. PP&L St. 2, Exh. PRM 2, Schedule 1. These figures are based on PP&L's actual cost of debt and preferred stock at December 31, 1996, the end of the base year in this proceeding. These embedded cost rates are not in dispute.

194. PP&L included in its calculation of stranded costs the present value (as of January 1, 1999) of its generation-related net regulatory assets. The Company initially claimed $383,911,000 for such assets in its Restructuring Plan filing. PP&L Exh. JRS 1, Tab B, p. 1 of 117. PP&L subsequently revised its claim during the course of this proceeding to $354,326,000, a reduction of $29,585,000. PP&L Exh. JRS 1A, p. 1 of 121.

195. On December 13, 1996, the Company filed an Application with the Commission requesting permission to roll its Energy Cost Rate ("ECR") and State Tax Adjustment Surcharge ("STAS") into base rates in response to Section 2804(4) of the Act, 66 Pa.C.S. § 2804(4), which establishes price caps on the Company's rates. The Company's Application requested Commission permission to defer as a regulatory asset: (1) unrecovered energy costs as of December 31, 1996; and (2) a normalized level of estimated future on-going energy costs. On December 19, 1996, the Commission issued a Tentative Order at Docket Nos. P-00961131 and R-00963842 approving PP&L's Application ("Tentative Order"). PP&L St. 3, pp. 9-11.

196. The Tentative Order created two regulatory assets, both of which are reflected in the Company's Restructuring Plan filing. First, PP&L is claiming the actual undercollection of $17.2 million in energy costs as of December 31, 1996. Second, the Company seeks to include in its stranded cost calculation approximately $31.2 million of normalized, on-going future energy costs on an annual basis. PP&L St. 3, p. 11; PP&L St. 3-R, p. 19.

197. OCA witnesses La Capra and Catlin, and PPLICA witness Kollen oppose the Company's claim of $31.2 million on an annual basis for future on-going energy costs. OCA St. 1, pp. 6-8; OCA St. 3, pp. 5-7; PPLICA St. 3, pp. 17-21.

198. PP&L Exhibit JMK 5 provides a calculation of the five-year average of actual energy costs incurred by the Company during the period 1992 through 1996. This five-year average amount demonstrates that PP&L's estimated future on-going energy costs will exceed the level of energy costs rolled into base rates on January 1, 1997 as a result of the Tentative Order by approximately $31.2 million annually. PP&L St. 3-R, Exh. JMK 5.

199. Based on actual energy costs for the period January 1, 1997 through June 30, 1997, the Company already has under-recovered $22.5 million of the energy costs included in its base rates. PP&L St. 3-R, pp. 19-20. The Company expects to underrecover its energy costs by approximately $36 million in 1997 and $67 million in 1998. PP&L St. 3-R, p. 19, Exh. JMK 6.

200. The Company's claimed stranded costs reflect estimated additional severance and pension costs that PP&L expects to incur between 1997 and 2001 as a result of its projected decline in the number of employees as the Company prepares for a competitive market. PP&L St. 8, pp. 25-26; PP&L Exh. JRS 1, Tab F, p. 40 of 117. The Company calculated a five-year amortization of the costs incurred in each year, and included in its calculation of stranded costs $17.106 million, the net present value of the recovery of these deferred costs that are allocable to the generation function. PP&L St. 8, pp. 25-26.

201. The OCA argues that the claimed employee transition costs for 1997 and 1998 should be excluded. OCA St. 3, p. 10. This adjustment would reduce the balance of regulatory asset for employee transition costs by $10.793 million. The OCA also contends that incremental pension benefits should be excluded because such benefits will not result in added out-of-pocket costs due to the overfunded position of the pension plan. This adjustment would further reduce the regulatory asset by $8.003 million. As a result of these two adjustments, the OCA recommends that the Commission allow only $3.483 million of future on-going employee transition costs as a regulatory asset. OCA St. 3, p. 11.

202. PPLICA asserts that PP&L's claimed future on-going employee transition costs are speculative, and that the Company failed to reflect normal employee attrition in its calculations. PPLICA St. 3, pp. 22-23. Even if the Commission "conceptually" adopts this regulatory asset, PPLICA argues that such asset should be valued at $5.502 million, the net present value of future cash outlays. PPLICA St. 3, p. 23.

203. The evidence shows that the additional severance and incremental pension costs that the Company is claiming and expects to incur are the result of PP&L's transition to a competitive market. These costs are explicitly identified in the definition of "transition or stranded costs" in Section 2802 of the Act. The cost savings attributable to the anticipated employee reductions are reflected in A&G expenses related to the generation function which are included in operation and maintenance expenses. PP&L projected that A&G expenses will decline between 1997 and 2001 as the Company prepares for competition, rather than increase at an annual inflation rate of 2.5 percent. PP&L St. 8-R, p. 50.

204. PP&L also fully reflected normal employee attrition for the period 1997 through 2001 in its calculations. The Company used a conservative estimate of employee attrition even though the actual historical rate of attrition has averaged approximately 2.5 percent. Indeed, PP&L expects the rate of "normal" attrition to be even lower than the historic rate because a large number of employees already have left PP&L as a result of its restructuring initiatives. Despite this anticipated downward trend, the Company elected to utilize a more conservative forecast in calculating employee transition costs, and assumed that as many as 5 percent of the projected 381 departing employees would leave as a result of "normal" attrition. PP&L St. 8-R, pp. 51-52.

205. The OCA's recommendation to exclude incremental pension benefit costs also is not supported by the record evidence. The OCA's argument rests on the fact that the Company's pension plan is currently "overfunded."

206. The value of future pension benefits earned by all participants during the current year is approximately $32 million per year for 1997. However, the stock market's performance has produced a substantial amortized, unrecognized net gain that reduces the amount included in expenses and used to project future costs to only $5.7 million for 1997. Any additional offset to reflect "excess" plan assets as a regulatory liability, including OCA's recommended disallowance would "double count" the unrecognized net gains unless the full $32 million of the annual value of benefits earned is used as the basis for charges to customers. PP&L St. 8-R, pp. 31-32.

207. Mr. Kollen recommends that the Commission recognize a regulatory liability of $253.832 million at December 31, 1998 associated with the Company's alleged "excess" pension fund assets. PPLICA St. 3, pp. 14-16. In Mr. Kollen's view, the purported overfunding may be "utilized by the Company either to offset future pension expense or to withdraw in some manner, albeit with certain limitations and penalties."

208. Mr. Kollen's proposed adjustment in inappropriate. As Mr. Schadt explained. PP&L St. 8-R, p. 33):

> Mr. Kollen's pension fund adjustment amounts to trying to pay two bills with one check. Mr. Kollen would not change the pension expense reflected in the filing, the amount of which is reduced substantially by actuarial calculations that take into account, on an ongoing basis, the total value of current plan assets and projected earnings on those assets. He then, having taken advantage of the projected long-term value of those assets to reduce pension costs already reflected in the filing, recommends that the same assets be used over again to reduce regulatory assets.

209. The evidence establishes that "the full amount of the plan's assets and obligations are already and appropriately being used to lower the amounts currently charged to ratepayers and to offset future pension expense, which lowers the Company's estimate of stranded costs." PP&L St. 8-R, p. 32.

210. In its Restructuring Plan filing, PP&L reflected $189 million for taxes recoverable in its calculation of stranded costs. The Company's claim was calculated using the regulatory method which reflects the recovery of these costs over a 30-year period. As explained by Mr. Schadt, that method permits a simple straightforward calculation of taxes recoverable:

> A comparison of future book depreciation with future tax depreciation identifies exactly the future period in which the taxes will become payable. This also is the period in which taxes recoverable should be collected from ratepayers, under traditional ratemaking. Note that this is true because the proper linkage exists between rate base, deferred taxes and taxes recoverable. As rate base is depreciated over time, deferred taxes become payable to the government and taxes recoverable become due from ratepayers. PP&L St. 8-R, p. 14.

211. The OCA and PPLICA recommend that the Commission adopt the asset value method to calculate PP&L's stranded costs. As all parties acknowledge, however, the asset value method cannot be used to calculate taxes recoverable. To address this problem, Mr. La Capra uses the regulatory method to calculate these costs. However, it is only appropriate to utilize the regulatory method to calculate stranded costs related to taxes recoverable if such method is used consistently with the regulatory model, i.e., the difference between book depreciation and tax depreciation "drives" taxes recoverable. PP&L St. 8-R, p. 16. As Mr. Schadt explained, "[i]f book depreciation is eliminated from the calculation of stranded costs, as it is in the asset value model, there is absolutely no theoretical justification for amortizing taxes recoverable on the basis of book depreciation, and alternative amortization logic must be developed . . . ." PP&L St. 8-R, p. 16.

212. Existing accounting rules will require PP&L to recognize that stranded generation costs will be recovered through the CTC over a seven-year period. Consequently, related unfunded deferred taxes also will reverse over the same seven-year period, which in turn requires the reversal of taxes recoverable over the same seven-year interval. Thus, when properly calculated under the asset value method, stranded costs for taxes recoverable equal the present value of the Company's $548 million of taxes recoverable discounted over a seven-year period, or $419 million. PP&L St. 8-R, pp. 16-17. Mr. La Capra's hybrid approach fails to reach this result.

213. PP&L included Taxes Other Than Income in its calculation of stranded costs. The Company's claim includes two components: (1) capital stock taxes; and (2) Public Utility Realty Tax ("PURTA"). PP&L calculated the actual amount of capital stock and PURTA taxes in 1996 applicable to fossil and nuclear generation facilities. The Company then escalated the 1996 taxes at the rate of inflation (2.5 percent) over the life of each generating facility. PP&L St. 8-R, p. 35; PP&L Exh. JRS 1, pp. 4-5.

214. OTS, OCA and PPLICA each oppose the Company's claim. OTS and PPLICA argue that capital stock taxes should remain constant over the life of each generating facility, but that PURTA taxes should decline in relation to the decline over time in net plant balance resulting from depreciation. OTS St. 2, pp. 16-23; PPLICA St. 2, pp. 50-51. Adoption of OTS' adjustment would reduce PP&L's nuclear generation-related

stranded costs by \$280.7 million, and its fossil generation-related stranded costs by \$66.1 million. OTS St. 2, pp. 22-23. OCA recalculated PP&L's stranded costs assuming that Taxes Other Than Income would remain constant over the life of the Company's nuclear and fossil generating facilities reducing PP&L's stranded costs by \$182 million. OCA St. 1, p. 16.

215. Section 2810 of the Act states that the transition to retail competition shall be revenue neutral as to the Commonwealth. 66 Pa.C.S. §2810. To achieve revenue neutrality, PP&L's claim reflects two assumptions. First, PP&L assumed that, similar to the Company's costs, the cost of services provided by the Commonwealth would increase with inflation. Second, PP&L assumed that the various tax revenues collected by the Commonwealth would increase proportionally to fund the higher cost of goods and services.

216. PP&L's claim is fully consistent with the requirements of Section 2810 because it assures that the transition to competition will be revenue neutral with respect to the Commonwealth. The opposing parties' recommendation would freeze capital stock and PURTA tax revenues to the Commonwealth at 1996 levels. This recommendation is inconsistent with the revenue neutrality goal of the Act.

217. PP&L's calculation of stranded costs includes \$315.867 million attributable to the costs of decommissioning its various fossil generating units. PP&L escalated each fossil plant's decommissioning costs at a 2.5 percent annual rate of inflation to the end of its book life. The Company assumed that it would incur decommissioning costs over a three-year period -- 40 percent in the year each plant is retired, 40 percent the following year, and 20 percent the next year. PP&L Exh. JRS 1, p. 8.

218. The OCA and PPLICA recommend that the Commission exclude the Company's claimed costs in their entirety. Generally, the parties offer four arguments. First, the OCA asserts that fossil decommissioning costs "simply do not fit the definition of stranded costs." OCA St. 1, p. 18. Second, PPLICA contends that the Company's claimed costs are speculative and unsupported. PPLICA St. 3, pp. 30-35. Third, PPLICA argues that recovery of such future costs consistently has been denied. Fourth, OCA and PPLICA contend that allowance of PP&L's claim would provide it with a competitive advantage over non-Pennsylvania utility fossil generation suppliers who must incur decommissioning costs without the prospect of recovering such expenses from customers through a CTC. OCA St. 1, p. 18; PPLICA St. 3-S, p. 31.

219. Section 2803 of the Act defines "transition or stranded costs" as including "retirement costs attributable to the utility's existing generating plants other than the costs defined in Paragraph (1)," which refers to the recovery of nuclear generating plant decommissioning costs. 66 Pa.C.S. § 2803. Thus, fossil decommissioning which are incurred to retire existing fossil generating facilities are defined by the Act as allowable "transition or stranded costs."

220. PPLICA argues that the Company's claimed fossil decommissioning costs are speculative and unsupported. Specifically, Mr. Kollen asserts that PP&L's claim derives from a fossil decommissioning study performed by TLG Services which is based on three erroneous and speculative assumptions: (1) PP&L's fossil generating facilities will be decommissioned while owned and controlled by the Company; (2) the facilities will be retired on the dates indicated in the study; and (3) the facility sites will be restored to "greenfield" conditions. PPLICA St. 3, pp. 31-32.

221. PP&L in fact has submitted substantial evidence in this proceeding which fully supports its estimated future fossil decommissioning costs. Indeed, past industry experience suggests that PP&L's claim may be understated, as decommissioning estimates generally have proven to be much lower than the actual costs incurred. PP&L St. 3-R, p. 34. The TLG study is very similar to other studies relied upon by the Commission to establish allowable levels of nuclear decommissioning expense. Tr. 1486. The nuclear decommissioning study performed by TLG and relied upon by the Commission in PP&L's last base rate proceeding contained the same types of assumptions that Mr. Kollen now attacks in the TLG fossil decommissioning study in this proceeding. Tr. 1486-1488.

222. PP&L's estimate of stranded generation-related capital and operating expenses was calculated utilizing the revenue requirements methodology contemplated by the Act. PP&L St. 3-R, pp. 31-32. Using this methodology, the Company included in its calculation the costs of decommissioning existing fossil generating facilities that would be recoverable under traditional rate regulation at the end of the lives of those facilities. Thus, PP&L's claim reflects its projected fossil decommissioning costs at the point in time when they actually would be incurred. PP&L St. 3-R, p. 32.

223. The OCA's and PPLICA's competitive advantage argument is inconsistent with the Act and, in fact, would place PP&L at a competitive disadvantage. The owners/operators of non-Pennsylvania utility fossil generation facilities can provide for the cost of decommissioning over the lives of their facilities. Pennsylvania utilities, however, must defer the recovery of fossil decommissioning costs until the costs are actually incurred. Pennsylvania electric utilities are required to seek and obtain stranded cost recovery of those costs or be placed at a significant competitive disadvantage. PP&L St. 3-R, pp. 32-33.

224. While OTS does not oppose PP&L's proposed stranded cost recovery of fossil decommissioning costs, Mr. Gruber recommends that the Commission require the Company to place all amounts recovered in a separate, non-qualified trust fund that would be accessible only as fossil decommissioning costs are actually incurred. OTS St. 1, p. 15.

225. Mr. Gruber's recommendation is inappropriate and inconsistent with Section 2806(A) of the Act that provided that "the generation of electricity shall no longer be regulated as a public utility service or function . . ."

226. Under the Act, PP&L is required to bear all of the risk associated with the estimate of its fossil decommissioning costs. Specifically, the Act permits the stranded cost recovery of the net present value of PP&L's projected fossil decommissioning costs. Thus, PP&L must bear the risk that its estimate understates such costs.

227. In recognition of this substantial risk, PP&L should not be required to place the amounts collected in a separate trust fund. PP&L St. 3-R, pp. 34-35.

228. In calculating the annual revenue requirement for nuclear generation, the Company included the amount it is recovering in annual nuclear decommissioning expense through existing retail and wholesale rates, adjusted to the appropriate PUC-jurisdictional amount. PP&L St. 8, p. 11. Currently, PP&L is recovering approximately $9.5 million per year in jurisdictional rates for nuclear decommissioning costs. PP&L St. 3, p. 15. PP&L's stranded cost claim reflects the net present value of after-tax future annual nuclear decommissioning expense accruals over the remaining life of the Company's nuclear facilities.

229. PP&L also proposes, as its preferred alternative, to recover its nuclear decommissioning costs over the remaining life of its nuclear generating facilities. PP&L St. 3, p. 14. Such costs would be recovered as part of distribution charges on a per kWh basis. PP&L St. 3-R, p. 28.

230. The Company's proposal is reasonable because it will ensure that it fully recovers its nuclear decommissioning costs over the remaining life of its facilities, and that it retains its exemption from burdensome NRC financial assurance requirements.

231. Two concerns underlie PP&L's proposal for recovery of nuclear decommissioning costs. First, there is some question as to whether the transition to full competition will ensure the adequate recovery of nuclear decommissioning costs. Section 2808 of the Act, 66 Pa.C.S. § 2808, provides electric utilities "an opportunity" to recover stranded costs through the CTC, including nuclear decommissioning costs that may not be recoverable in a competitive generation market. Thus, PP&L will have to fund a substantial amount of its nuclear decommissioning costs using revenue from market rates. There is no assurance, however, that such market rates will be sufficient to satisfy PP&L's nuclear decommissioning funding obligations. PP&L St. 3, p. 12.

232. Second, there is a risk that the transition to full competition could subject PP&L to substantial financial qualification requirements under Nuclear Regulatory Commission ("NRC") regulations. Specifically, NRC regulations exempt "electric utilities" to provide additional financial assurance for nuclear decommissioning (e.g., insurance or surety bond) beyond establishment of an external sinking fund. "Electric utilities" are defined as "any entity that generates or distributes electricity and which recovers the cost of electricity, either directly or indirectly, through rates established by the entity itself or by a separate regulatory authority." 10 C.F.R. § 50.2

233. Under traditional cost-of-service rate regulation, PP&L satisfies the NRC's definition of "electric utility" because its rates are set by the Commission. PP&L currently is authorized to recover its estimated future nuclear decommissioning costs in rates over the remaining life of its nuclear generating facilities, and all recovered amounts are placed in an external trust fund. However, the Act requires that all generation-related costs, including those related to PP&L's nuclear generating facilities, be removed from traditional rate regulation. PP&L's proposal to recover its claimed costs through a distribution charge is designed to address both of these concerns. PP&L St. 3, pp. 13-14. PP&L's proposal will ensure adequate nuclear decommissioning funding and will provide for the recovery of such costs through rates established by the Commission. PP&L St. 3, pp. 14-15.

234. PPLICA and the Environmentalists oppose the Company's proposal. PPLICA contends that PP&L's proposal to recover nuclear decommissioning costs on a per kWh basis is inconsistent with its treatment of such costs in its last base rate case. PPLICA St. 1, pp. 55-56.

235. Mr. Baron is in error. The Company unbundled costs in this case using the same demand allocators utilized in its last base rate proceeding. Thus, PP&L's proposed unbundled tariff rates reflect nuclear decommissioning costs allocated among customer classes on a demand basis. The Company proposes to recover these demand-allocated costs on a per kWh basis, which is the same method currently used to recover such costs through fully regulated rates. PP&L St. 3-R, pp. 28.

236. The Environmentalists oppose PP&L's proposal to extend the CTC, and recommend that the Commission consider "the benefits of an incentive framework for nuclear decommissioning costs, in which risks are shared between the Company and its customers." Environmentalists St. 2, p. 28.

237. PP&L's proposal is consistent with the Act, which clearly states that the PUC "shall" provide for recovery of nuclear decommissioning costs. 66 Pa.C.S. § 2808(c)(1). Moreover, adoption of this proposal would clearly jeopardize PP&L's NRC status as an "electric utility" and could result in a pre-funding requirement that would impose an additional burden on customers. See also PP&L St. 3-R, pp. 29-30.

238. PPLICA initially opposed the Company's proposal to recover nuclear decommissioning expenses as a distribution-related component of its delivery charges, claiming that PP&L would recover such expenses twice. PPLICA St. 3, p. 39. In rebuttal, PP&L explained that it would exclude nuclear decommissioning costs from those recovered through the CTC if the Commission adopts the Company's proposal. PP&L St. 3-R, p. 29. Based on this clarification, PPLICA agreed that PP&L's proposal would not result in the double recovery of nuclear decommissioning costs. PPLICA St. 3-S, p. 33.

239. The Energy Policy Act of 1992 ("Energy Act") establishes an assessment on utilities, including PP&L, with nuclear power operations to provide funds for the decontamination and decommissioning of the Department of Energy's ("DOE") uranium enrichment facilities. Under the Energy Act, this charge is assessed over a 15-year period, and is deemed a necessary and reasonable current cost of fuel that is fully recoverable in rates in the same manner as other fuel costs. PP&L St. 8, p. 24.

240. PP&L determined the amount of DOE assessment costs that would be recovered annually through existing rates, and included the present value of the PUC-jurisdictional portion of this amount in its calculation of stranded cost. PP&L St. 8, p. 24.

241. The OCA and PPLICA recommend that the Commission disallow the Company's claim in its entirety, noting that PP&L already reflected this assessment in its Restructuring Plan filing as a component of fuel expense. OCA St. 3, p. 7; PPLICA St. 3, pp. 24-25.

242. In response, the Company eliminated all DOE assessment amounts from the fuel expense component of its generation-related costs, which reduced PP&L's stranded costs by approximately $17 million. PP&L St. 8-R, pp. 56-57. This correction fully addresses the OCA's and PPLICA's concerns.

243. PP&L's stranded cost calculation includes a claimed regulatory asset for incremental maintenance costs incurred during refueling and inspection outages PP&L's Susquehanna Steam Electric Station ("SSES"). These costs are deferred and amortized from the end of the outage until the next scheduled refueling and inspection outage is completed. The Company determined the annual recovery that would occur through existing rates and included in its stranded cost calculation $7.996 million on a present value basis at December 31, 1998 for the PUC-jurisdictional portion of these costs. PP&L St. 8, p. 25.

244. OTS, OCA and PPLICA each oppose the Company's claim for deferred SSES refueling expenses, asserting that refueling expenses are typical, ongoing costs that properly should be normalized, not deferred and amortized for future recovery. OTS St. 2, p. 15.

245. The Company's claim is fully consistent with the manner in which PP&L historically has accounted for and recovered SSES refueling costs. PP&L did not claim costs associated with the first refueling outage of SSES Unit 1 in its 1983 SSES Unit 1 rate filing with the Commission (Docket No. R-822169). Instead, the Company requested and received permission to defer and amortize its incremental refueling costs over the period of time from the date of restart following the outage until the date of restart after the next outage. PP&L St. 8-R, p. 46.

246. PPLICA and OCA contend that PP&L's claimed costs are premised on a change in accounting caused by the Company's change to a 24-month refueling cycle for SSES Unit 1 in 1997 and for SSES Unit 2 in 1998. PPLICA St. 3, p. 36; OCA St. 3, p. 9. As a result of this change, PPLICA notes that SSES Units 1 and 2 will undergo refueling outages in alternate years, which will cause the Company to expense actual outage costs each year. PPLICA and OCA argue that, despite these changes, PP&L has failed to modify its accounting practices to eliminate deferrals and amortizations in 1997 and 1998, and instead "has assumed that it can defer the accounting recognition of those changes into the subsequent to 1999' period, although it had no accounting order from the Commission that authorized such a deferral." PPLICA St. 3, p. 37. PPLICA and OCA, therefore, recommend that the Commission disallow the Company's request.

247. PPLICA's and OCA's recommendation is in error. PP&L was authorized to accumulate and defer the first refueling outage costs for SSES Unit 1 over the subsequent fuel cycle. Thus, PP&L always has been one cycle behind in recovering refueling outage costs. The parties' recommendation would result in an improper matching of outage costs and revenues. PP&L St. 8-R, pp. 48-49.

248. In its Final Order at Docket No. R-00943271, the Commission authorized PP&L to recover the full PUC-jurisdictional portion of expenses attributable to the adoption of Statement of Financial Accounting Standards 106 ("SFAS 106"). SFAS 106 requires PP&L to record the liability associated with post-retirement benefits on an accrual basis (i.e., at present value), rather than on a pay-as-you-go or cash basis. The Company's current rates recover the full SFAS 106 costs applicable to PUC-jurisdictional customers, including approximately $11 million in excess of PP&L's current cash payment obligation for post-retirement benefit claims to recover the transition obligation or accrued liability that existed as of January 1, 1993, the date PP&L adopted SFAS 106. The transition obligation is being amortized over 20 years. PP&L St. 8, p. 22; PP&L St. 8-R, pp. 41-42.

249. The Company determined the annual recovery of SFAS 106 costs that would occur under existing rates and included the present value of the PUC-jurisdictional portion of the generation-related amount in its calculation of stranded costs. PP&L St. 8, p. 22.

250. PPLICA generally accepts the Company's claim, but recommends that the Commission recognize a regulatory liability for the interest earned by trust funds established by PP&L to fund post-retirement benefits other than pensions. PPLICA St. 3, pp. 26-29. In PPLICA's view, this regulatory liability should be used to offset PP&L's claimed regulatory asset.

251. PPLICA's proposed adjustment is inappropriate because the interest identified by Mr. Kollen already is utilized to offset or reduce the projected cost of post-retirement benefits other than pensions. PP&L St. 8-R, p. 40. PPLICA's proposal, if adopted, would increase PP&L's estimated generation-related stranded costs. PP&L St. 8-R, pp. 42-43.

252. With the change in Federal tax laws that allowed PP&L to take advantage of investment tax credits ("ITCs"), the Company elected to defer recognition of these credits as income by recording a liability for accumulated deferred ITCs. The amortization of accumulated ITC's, along with the related income tax effect, reduces the cost-of-service (and thus customer rates) over the lives of the assets that produced the ITCs. As a result of the adoption of Statement of Financial Accounting Standard No. 109 ("SFAS 109"), PP&L recorded a deferred tax asset to reflect the income tax effect of the accumulated deferred ITCs, and a regulatory liability (i.e., an amount owed to customers) to reflect the ratemaking treatment of the tax effect. This regulatory liability is equal to the reduction in income tax expense that will need to be recovered from customers as the balance of accumulated deferred ITCs is amortized to reduce the cost-of-service over the remaining lives of the underlying assets. PP&L St. 8, pp. 28-29.

253. In its Restructuring Plan filing, PP&L utilized the present value of the ITC regulatory liability to reduce or offset the present value of regulatory assets in calculating the level of its stranded costs. The methodology used by the Company to reflect the effect of the ITC regulatory liability is not opposed by any party in this proceeding.

254. In calculating its stranded cost claim, PP&L utilized the same deactivation dates for its generating facilities that were approved by the Commission in the Company's most recent base rate case at Docket No. R-00943271. Specifically, the Keystone and Conemaugh generating stations are scheduled to be deactivated in 2007 and 2010, respectively. These deactivation dates also are fully consistent with the depreciation schedules reflected in PP&L's retail customer rates as of January 1, 1997. PP&L St. 10-R, pp. 33-36.

255. The OCA and PPLICA recommend that the Commission extend the deactivation dates for both the Keystone and Conemaugh generating stations to match the dates utilized by PECO Energy Company ("PECO") for its share of these plants in its Restructuring Plan proceeding at Docket No. R-00973953. OCA St. 1, p. 16; PPLICA St. 3, pp. 31-32.

256. PP&L's proposed deactivation dates are consistent with the expected operating life for this type of generating unit. Specifically, the Keystone units began service in 1967 and 1968. Based on the deactivation date approved by the Commission in PP&L's last base rate case, i.e., 2007, these units have projected service lives of 40 and 39 years, respectively. Similarly, the Conemaugh generating units began operation in 1971 and 1972. Based on the deactivation date approved by the Commission in PP&L's last base rate case, i.e., 2010, these units have an expected operating life of 39 and 38 years. PP&L St. 10-R, pp. 35-36. As Mr. Krall explained, the Company's proposed deactivation dates properly reflect the design and operating limitations for these units. PP&L St. 10-R, p. 36.

257. The parties' reliance on PECO's proposed deactivation dates is misplaced. In fact, the various owners of Keystone and Conemaugh frequently have utilized different deactivation dates in establishing their respective rates. The Commission has reviewed and approved each of these dates.

258. Mr. Kollen is incorrect in asserting that PECO's deactivation dates should be utilized because PECO operates the Keystone and Conemaugh units. The record evidence demonstrates that these generating units are operated by GPU subject to oversight by the Keystone-Conemaugh Projects Office. PECO, like PP&L, is a joint owner, and no owner may unilaterally cause investments at these stations that would extend their lives. Such investment decisions require approval by 75% of all ownership shares. Because the

Commission lacks jurisdiction over five of the owning companies whose ownership shares exceed 25%, the Commission is unable to require investments to extend the lives of these stations. PP&L St. 10-R, p. 37.

259. PP&L's proposed deactivation dates are appropriate. The proposed dates are identical to the dates approved by the Commission in the Company's last base rate case, and are fully consistent with the expected operating lives of the facilities.

260. The Company included in its calculation of stranded costs the present value of the generation-related portion the total annual recovery of rate case expenses that would occur through existing rates. The Commission authorized PP&L to recover rate case expenses associated with its base rate proceeding at Docket No. R-0094371 over a four-year period. PP&L St. 8, p. 26.

261. Raising the same argument used in opposition to PP&L's claim for deferred SSES refueling expenses, the OTS and OCA recommend that the Commission disallow the Company's claim. Specifically, Messrs. Reed and Catlin argue that the Commission previously approved normalization of PP&L's rate case expenses, not deferral and amortization of such costs. OTS St. 2, pp. 13-16; OCA St. 3, p. 12. Disallowance of the unamortized expenses would reduce the nominal balance of the Company's regulatory assets by $184,000. OCA St. 3, p. 12.

262. PP&L properly included the balance of its unamortized rate case expenses as a regulatory asset in its Restructuring Plan filing. SFAS 71 allows a regulated entity to match incurred costs with their associated revenues for accounting purposes using regulatory assets. Under SFAS 71, the recorded regulatory assets are charged, concurrently with the recovery of such amounts in rates, to the same account that would have been charged if included in income when incurred. Based on the Commission's Final Order in PP&L's last base rate proceeding, the Company appropriately created a regulatory asset in September 1995 for the 1994 Rate Case Expenses to be amortized over a four-year period. Consistent with the Act, PP&L reflected the present value of the post-1998 recovery of the generation-related costs in its calculation of stranded costs. PP&L St. 8-R, pp. 39-40.

263. On rebuttal, the Company corrected an error in its original stranded cost calculation related to the Safe Harbor facility. Specifically, PP&L's initial calculation did not include the energy revenues and the operating and maintenance expenses associated with this facility. The revenues related to Safe Harbor's capacity inadvertently were included with the Holtwood Dam hydroelectric project's revenues for capacity. The effect of properly including the remaining revenues for energy from Safe Harbor and all of its operating and maintenance costs increases PP&L's stranded costs by $38 million. PP&L St. 8-R, pp. 55-56. These corrections are shown in PP&L Exhibit JRS 8.

264. PP&L's stranded claim included the generation-related portion of its Administrative and General ("A&G") expenses between generation and T&D using the same allocation factors approved by the PUC in PP&L's 1995 rate case. OCA witness La Capra recommends that the Commission exclude certain A&G expenses from the Company's going-forward generation-related costs. OCA St. 1, p. 16.

265. By excluding these costs from generation-related expenses and failing to reallocate them to the transmission and distribution function, Mr. La Capra effectively eliminates the claimed A&G expenses and precludes their recovery. Mr. La Capra's proposal is in error. The claimed A&G costs are necessary for PP&L to continue to provide safe and reliable service to its customers. These costs will not disappear following the transition to competition. If these costs are not recovered as generation-related stranded costs, they must be reallocated and recovered through regulated transmission and distribution rates.

266. OCA proposed a productivity factor of 0.2% to reduce projected future operation and maintenance expenses and alleges that PP&L failed to reflect possible future productivity gains. OCA St. 1, pp. 24-25.

267. Contrary to OCA's assertions, PP&L did use a productivity factor in its calculations of stranded costs. Instead of increasing administrative and general costs, a component of operation and maintenance expenses, by 2.5% annually, the inflation rate used in other portions of PP&L's calculation, PP&L reduced

administration and general costs by an average of 2% annually for each year after 1997 through 2001. PP&L's method of reflecting increased productivity reduces PP&L's stranded costs even more than OCA's method. PP&L St. 8-R, pp. 54-55; Ex. JRS 7. The additional adjustment proposed by OCA is unjustified because it would "double count" PP&L's projected reductions in operation and maintenance and administrative and general expenses of $513 million. PP&L St. 2, p. 16. A portion of these expense reductions undoubtedly will come from increased efficiency of employees. There is no basis for the OCA's adjustment.

268. The OCA asserts that PP&L has failed to recognize the value of the real estate on which its generation units are located as a factor mitigating its overall level of stranded costs. OCA St. 1, pp. 28-29. In OCA's view, the minimum value of such real estate is $66 million. OCA Exh. RLC-6. The OCA's analysis is flawed and its adjustment is significantly overstated, and it should be rejected.

269. The OCA recommends that the Commission adopt the asset value methodology to determine the Company's stranded costs. OCA St. 1, pp. 14-15. In its calculations, the OCA treats capital additions as expenses in the year in which they are incurred. Similarly, the OCA reflects the full associated tax deductions in the year in which the underlying capital expenditure is incurred.

270. The OCA's treatment of capital additions is in error. The proper treatment of capital expenditures is to record depreciation expense ratably over the life of the investment and to provide for a return on the undepreciated balance, *i.e.*, rate base. OCA's asset value method cannot handle this complexity so Mr. La Capra makes the simplifying assumption that the entire expense was incurred in the year it was made. From an expense standpoint this is acceptable, as long as the discount rate is the same as the return which would have been allowed if the investment were depreciated under normal ratemaking practice.

271. The problem with OCA's analysis lies in its treatment of taxes. OCA assumes that the tax deduction for the entire capital expenditure can be taken in the year it was made. This, of course, is not true. The tax laws require that a deduction equal to the nominal value of the expenditure be spread over the life of the investment utilizing IRS tax depreciation guidelines. As a result of this error, OCA significantly understates the actual cost of capital additions and overstates net market revenue by overstating the tax reducing effect of the expenditure. This error caused the OCA to understate PP&L's stranded costs by $165.318 million.

VI. DETERMINATION OF PRESENT VALUE

272. PP&L used the regulatory method to calculate its stranded costs. Under this method, the Company compared the revenue stream it could have received under traditional cost-of-service regulation with the stream of revenue it could receive in a competitive market. PP&L discounted the difference between these two amounts to January 1, 1999 using a discount rate of 7.92%, which is PP&L's after-tax weighted average cost of capital ("WACC"). PP&L St. 8-R, p. 5; PP&L Exh. JRS 1, p. 1.

273. OSBA witness Knecht argues that PP&L's proposal to use a 7.92% after-tax WACC "would provide a higher [net present value] return to equity holders under deregulation plus CTC than under continued regulation." OSBA St. 1, p. 21. To address this alleged problem, Mr. Knecht asserts that the Commission should adopt PP&L's proposed 11.5% after-tax cost of equity as the appropriate discount rate. OSBA St. 1, p. 16. Under Mr. Knecht's proposal, PP&L would underrecover less than $100 million of its total stranded costs. OSBA St. 1, p. 24. Mr. Knecht purports to support his adjustment both algebraically and with an example. OSBA St. 1, pp. 18-21; OSBA Exh. RDK-2, Schedules 1-3.

274. Mr. Knecht's proposal to use the after-tax cost of equity ignores the fact that PP&L has both equity *and* debt investors. Indeed, Mr. Knecht conceded this point during cross-examination. Tr. 804. As explained by Mr. Guth. PP&L St. 19-R, p. 23):

> a utility's earnings on capital invested consist of both earnings on equity and earnings on debt. Using the after-tax WACC takes into account the balance of earnings between equity and debt.

Under Mr. Knecht's proposal, however, a component of PP&L's total returns, i.e., interest paid to debt-holders, will be discounted at *equity* rates. PP&L St. 19-R, p. 24. This mismatch is inappropriate.

275. The OCA asserts that PP&L improperly applied an *after-tax* discount rate the calculate the present value of *pre-tax* revenue requirements and market prices. OCA St. 1, p. 13. As a result, the OCA claims that the Company overstates its stranded costs by $880 million. *Id.*

276. OCA's argument is in error. Stranded costs are analogous to economic damages because they represent a decrease in value caused by some act or event, in this case, the transition from regulated to market-based rates. PP&L St. 19-R, p. 20. As such, taxable stranded costs properly should be measured utilizing pre-tax cash flows and after-tax discount rates. PP&L St. 19-R, p. 21.

277. Messrs. La Capra and Falkenberg reflect income taxes in calculating the value of PP&L's generating assets, but fail to adjust stranded costs upward to account for the taxability of CTC revenues. PP&L St. 19-R, p. 21. As Mr. Guth explained, Messrs. La Capra and Falkenberg. PP&L St. 19-R, pp. 21-22:

> computed what they assert is the market value of PP&L's generating assets after taking into account income taxes. That procedure is all right, so long as measured stranded costs are then adjusted upward to take into account the taxability of CTC revenues that are based on stranded costs. Thus there really are two alternatives where the present value amount of future cash flows is taxable income:
>
> 1. use pre-tax cash flows, and after-tax discount rates to compute the present value of taxable income; or
>
> 2. use after-tax cash flows, and after-tax discount rates to compute the present value of after-tax income, then gross up the result for tax coverage.

The OCA's proposal is incorrect because it fails to adopt either of these approaches.

VII. RECOVERY OF STRANDED COSTS

278. Under Section 2808(a) of the Act, 66 Pa.C.S. § 2808(a), electric distribution companies will recover their stranded costs through "Competitive Transition Charges ("CTCs"). These charges will be applied to every customer of electric distribution companies.

279. Three statutory provisions influence the rate design of PP&L's CTCs. First, the CTCs are constrained by the rate caps. Under Section 2804(4)(ii) of the Act, there may be no increase in the generation component of rates, which includes the CTCs, for nine years from the Act's effective date, or through December 31, 2005. That is, throughout this period, the sum of each CTC and PP&L's charge for Basic Utility Supply ("BUS") Service may not exceed the generation component of rates charged to customers as of January 1, 1997. Second, Section 2808 of the Act mandates that the CTCs be designed "in a manner that does not shift interclass or intraclass costs and maintains consistency with the allocation methodology for utility production plant accepted by the Commission in the electric utility's most recent base rate proceeding." Third, PP&L's CTCs are designed in a manner to promote the overall purpose of the Act, which is to establish an active and viable retail market for electric generation.

280. In addition to these statutory considerations, PP&L has applied sound ratemaking principles in designing its CTCs. PP&L has sought to provide a more efficient marginal price signal to customers. PP&L St. 9, p. 20. Further, PP&L has simplified its delivery service rate design.

281. PP&L used a "bottom-up" approach to design its CTCs. PP&L St. 9, pp. 23-26. The starting point for this approach is presently-effective rates. The first step is to determine for each rate in each rate schedule, the

portion of the rate that is related to delivery of electric energy. This was determined by application of allocation percentages based upon a test year ended December 30, 1995. These allocation percentages were accepted in the Commission's Order entered in PP&L's most recent base-rate case (Docket No. R-00943271, order entered on September 27, 1995, at 197).

282. PP&L's next step in determining the CTCs is to subtract from the generation portion of each rate the projected retail market price of electric energy. The remainder after this substraction is the portion of the rate that is available for use as the CTC under the rate cap.

283. PP&L has determined that, under the rate cap, the maximum CTC revenue that can be attained over the transition period through 2005 is only $4.0 billion. St. 10-R, p. 3. Thus, due to the rate caps, PP&L's projected CTC revenues will fall $500 million short of recovering all of PP&L's estimated $4.5 billion of stranded costs. Therefore, PP&L set its proposed CTCs at the maximum amounts available under the rate cap after allowing for the projected retail market price of electric energy and the portion of each rate that is for delivery services.

284. Although the rate cap does not change throughout the transition period, the projected retail market price of electric energy increases each year of the transition period. Therefore, for each rate, there is a different CTC for each year of the transition period through 2005. See, *e.g.*, Exhibit OGK 2, Tariff Electric-Pa. P.U.C. No. 201, pp. 20-21.

285. PP&L's rate design for its CTC meets each of the statutory and ratemaking principles identified above. First, it successfully meets the Act's rate cap requirements. There will be no increase in PP&L's rates for generation service at least through 2005. The applicable rate cap under the Act is the presently-effective generation portion of the total rate. By calculating the CTC as the residual remaining after subtracting the delivery portion of the rate and the projected retail market cost of electric generation during the transition period (which is the maximum charge for PP&L's BUS Service) means that PP&L's proposed CTCs arithmetically cannot exceed the rate cap.

286. The evidence shows that PP&L's proposals will not cause shifting of costs between rate classes or within rate classes. The generation portion and the delivery portion of PP&L's present rates were determined by application of allocation percentages from the cost of service study used to design PP&L's present rates. St. No. 3, pp. 6-7; Exhibit JMK 1.

287. PP&L's CTCs have been designed to achieve simplicity in the delivery service rate design. The CTCs have declining blocks that follow PP&L's presently-effective rate design. The delivery charge includes the presently-effective customer charge and flat usage charges per kWh. Therefore, when the CTC is eliminated at the end of the transition period, the remaining charges of PP&L under rate schedules for most customers will be a customer charge combined with a flat energy charge for usage. Customers will understand this pricing structure and be able to work with it to obtain electric energy at the most favorable terms and conditions (St. 9, p. 21) .

288. Several intervenors suggest that, contrary to PP&L's proposal, the level of the CTC should be re-established periodically throughout the transition period based upon actual market prices. NEV St. No. 1, pp. 3-4, 7, 9; MAPSA St. 1, p. 2; Environmentalists St. 1, pp. 2, 8.

289. Recalculating CTCs periodically based upon ever changing market conditions would make effective competition extremely difficult. Without a known CTC, customers would not be able to compare the applicable rate cap for PP&L's BUS Service with proposals from alternative suppliers to determine whether using services of an alternative supplier would be more advantageous. PP&L St. 9-R, p. 11.

290. A CTC that is recalculated periodically could substantially defeat the benefits of competition for customers. If competition is effective and retail electric generation prices are lower than projected, PP&L's proposed CTCs would not provide for full recovery of its stranded costs. Thus, the result of a lower market price would be a higher CTC, not savings for customers. St. 9-R, pp. 18-19.

291. OCA, in its St. 4, pp. 9-14, and OSBA, in its St. 1, p. 12, recommend, based on an assumption that PP&L will be allowed to recover a much lower level of stranded costs than it has proposed, that recovery of stranded costs be spread over the transition period.

292. The OCA's and OSBA's proposal would delay recovery of the allowed level of stranded costs and would impose on PP&L an increased risk that it will be unable to recover all of its allowed stranded costs if market conditions change in the future. Moreover, the CTC should be set at the maximum level consistent with the rate cap until the allowed level of stranded costs is recovered because this approach will eliminate the distortions on the electric energy market prices caused by the CTCs at the earliest possible date. PP&L St. 9-R, pp. 22-25.

293. Various parties in this proceeding have proposed alternative methods for PP&L to recover its stranded costs. The proposals by other parties consist of "levelizing" or otherwise unnecessarily spreading recovery of stranded costs over time. These proposals are inappropriate. First, they are calculated on the unfounded assumption that a substantial portion of PP&L's stranded costs will be disallowed by the Commission. Second, levelizing recovery of stranded costs has the effect of shifting that recovery from the early years of the transition period to the later years. The result is a significantly adverse impact on PP&L's financial indicators in those early years, compounding the financial impact of any disallowance of stranded cost recovery.

294. AARP contends that costs should be reallocated so that a larger share of CTC revenues is derived from non-residential customers. AARP St. 1, pp. 28-29. In a similar vein, the Environmentalists contend that the Commission should take a fresh view of allocating stranded costs among the rate classes. Environmentalist St. 1, p. 26.

295. The AARP and Environmentalist proposals directly contravene the mandate of Section 2808(a) of the Act, which requires that the CTC be established in a manner that does not shift cost recovery either between classes of customers or within a customer class. The Act also specifies the manner in which this result is to be accomplished by requiring that stranded costs be allocated in the manner accepted by the Commission in each electric utility's most recent base-rate case. AARP and the Environmentalists ignore these statutory provisions.

296. The Act provides specific guidance concerning the reconciliation of CTC revenues and stranded costs. Section 2808(a) of the Act provides that annual CTC revenues shall be reconciled with the amortization of stranded costs authorized by the Commission for the same period.

297. PP&L proposes to implement this statutory mandate by following procedures, subject to one exception, similar to the annual Energy Cost Rate ("ECR") reconciliation procedures that had been in place in Pennsylvania for many years prior to the Act (St. 3, p. 17). PP&L proposes to track, on a system basis, its annual CTC revenues and compare those revenues with the annual amortization authorized by the Commission. PP&L would submit quarterly filings to the Commission reporting the results of the tracking process. However, in a departure from ECR practice, PP&L would not change its CTC annually to reflect overcollections or undercollections.

298. Because PP&L's rates will be at the rate caps throughout the transition period, PP&L would be precluded by the rate caps from recouping from customers any prior period undercollection. Accordingly, PP&L is proposing that the collection period be extended or contracted to permit reconciliation of overcollections or undercollections. That is, if CTC revenues exceed the authorized amortization, the CTC would be terminated at the appropriate time prior to December 31, 2005. Conversely, if CTC revenues were less than the amount authorized by the Commission, the CTC period would be extended beyond December 31, 2005.

299. Section 2808(b) of the Act provides that the CTC may be included in bills to customers for a period not to exceed nine years from the effective date of the Act, or December 31, 2005. The Act further provides, however, that the Commission "for good cause shown" may order an alternative payment period. This

alternative period may be longer or shorter than the nine-year period. PP&L has shown good cause why the period for application of the CTC should be extended if CTC revenues during the period ending December 31, 2005, fall short of the level of stranded costs that PP&L is authorized by the Commission in this proceeding to recover from customers. St. 3, pp. 18-19.

300. PP&L's proposal to extend the period for reconciliation of stranded costs also protects the interests of customers. First, if the Commission approves PP&L's proposal to extend the period for recovery of stranded costs beyond December 31, 2005, PP&L will voluntarily extend the generation-related rate cap to coincide with the extension of the period for application of the CTC. St. 3-R, p. 26. Second, the CTC will be known and predictable throughout the transition period facilitating comparisons by customers of PP&L's BUS Service with offerings by alternative electric energy suppliers. Third, PP&L has kept the CTC mechanism as simple as possible, and has proposed that the reconciliation process not reflect any calculations of interest on overcollections or undercollections of the annual CTC amortization.. PP&L St. 3-R, p. 25.

301. OCA has recommended that the CTC be reconciled by rate class. OCA St. 4, pp. 17-18.

302. There is no support for OCA's proposal in the Act. Section 2808(f) is silent on the subject. Of greater importance, however, are the facts that OCA's proposal would not solve the perceived problem that it is intended to address and that OCA's proposal would create additional problems. The problem that OCA apparently seeks to address is that stranded cost recovery will be usage dependent, and different rate classes will pay more or less than allocated amounts depending on future levels of usage. However, under OCA's proposed reconciliation by rate class, this "problem" will remain unresolved for customers within a rate class. Inevitably, customers using more energy in the transition period will pay more than they would under allocations based on historical usage. Similar problems arise from additions and losses of customers. These "problems" are unavoidable unless the CTC is to be an entirely fixed charge and based on historical levels of usage. No party has made such a proposal.

303. OCA's proposal also would have the potential to cause hardship. In rate schedules with few, large customers, hardships could be caused to remaining customers if one member of the rate class went out of business early in the transition period. Problems would be caused also by having the CTC terminate at different times for different rate schedules. Under these circumstances, some customers may be able to switch their service to a rate schedule without a CTC, thereby harming other customers or the Company.

304. A proper net present value determination must recognize also that PP&L's stranded costs will be recovered over seven years ending December 31, 2005. For the reasons that stranded costs are discounted to net present value, PP&L's recovery of stranded costs should be inflated to net present value.

305. Based on the Commission's Order in *PECO*, p. 108, the applicable rate to inflate PP&L's stranded costs to reflect the fact that recovery will take place over a seven-year period is PP&L's long term debt cost rate. *See also* PP&L St. 19-R, pp. 28-29. This rate, which is provided at PP&L Exhibit JRS 1, Tab A, Attachment 1, is 7.89%.

306. Regardless of the cost rate, however, a substantial portion of PP&L's assets, including stranded assets are financed with securities on which PP&L pays dividends that are subject to income taxes. For this reason, the portions of the amount to be inflated must be "grossed up" for income taxes. Exhibit JRS 1, Tab A, Attachment 1, provides PP&L's capital structure and cost rates. Exhibit JRS 1, Tab A, p. 4, provides its composite income tax rate of 41.4935%. Using these data, that have not been controversial in this proceeding, produces the appropriate rate to be applied to amounts to be recovered through the CTC over 7 years. Thus, the appropriate overall, pretax rate that should be used to inflate PP&L's CTC revenues, that will be received over a seven-year period, is 10.86%.

307. PP&L provides interruptible service under three rates schedules (IS-1, IS-P and IS-T). PP&L proposes to continue service under these rate schedules following transition to a competitive retail market for electric generation. Service, however, would be limited to premises presently receiving interruptible service and to

customers who choose to purchase PP&L's BUS Service (See, *e.g.,* Exhibit OGK 2, Tariff Electric — Pa. P.U.C. No. 201, p. 30C).

308. The CTC for the interruptible rate schedules is calculated in the same manner as for all other rate schedules, *i.e.*, the remainder after the projected retail price of electric generation and the delivery component of the rate are subtracted from the fully-bundled rate. As a result, the CTCs applicable to the interruptible rate schedules are extremely small. For example, in 1999, the tailblock CTC under Rate Schedule IS-T is 0.257¢ per kWh, and this amount is reduced every year through 2005 when the tailblock CTC is a negative 0.006¢ per kWh.

309. These low CTC's result because the interruptible rates are deeply discounted. These discounts are generation-related.

310. Another benefit to PP&L's system of providing interruptible service is that PP&L can interrupt sales to interruptible customers when the cost to PP&L of generation service is exceptionally high. PP&L St. 11-R, pp. 3-4.

311. The benefits of providing interruptible service are available to any alternative supplier of electric energy. Interruptible service enables an alternative supplier to sell energy, during its non-peak periods, without the need to construct or purchase generating capacity that would be necessary to meet the additional load. Moreover, alternative suppliers that purchase electric energy to resell to their retail customers can interrupt sales to interruptible customers to avoid costs whenever the price for electric energy is high. However, if an interruptible customer of PP&L purchases electric energy from competing suppliers, the interruptible nature of the service will benefit the competing supplier and possibly its customers, not PP&L and not PP&L's other delivery service customers.

312. Certain customers propose to continue to utilize interruptible rate schedules of PP&L while shopping for competing generation suppliers. This proposal is illogical. Under these circumstances, the interruptible customers would continue to receive from PP&L the benefit of a deeply discounted rate for interruptible delivery service while providing no reciprocal benefits to PP&L or its customers.

313. To date, PP&L has never interrupted service under the interruptible rate schedules due to load peaks on transmission or distribution facilities. To the contrary, all interruptions requested by PP&L have been the result of generation emergencies on the PJM interconnection, for emergency tests of interruptible service customers or for economic reasons. St. 11-R, p. 8. There is no basis for discounting any such service, and therefore, no reason for offering such a service.

314. The interruptible customers also object to the provisions of PP&L's proposed tariff, Exhibit OGK 2, p. 30E, which give PP&L more discretion in interrupting service for economic load control.

315. PP&L's proposed economic load control provision is appropriate to protect PP&L's other customers. Interruptible customers and all other customers using PP&L's residual BUS Service will receive bills for service that are based upon an annualized, average cost of such service, subject to the rate cap. Therefore, if interruptible customers use electric energy when prices are high, the cost that such customers cause PP&L to incur are shared with other customers if the price does not exceed the rate cap. PP&L's present tariff rule, which limits interruptions to 200 hours per year or 2.3 percent of the time (200 ÷ (24 x 365)) is not sufficient to protect the interest of other customers of PP&L receiving BUS Service.

316. Interruptible customers' concerns are misplaced because, during interruptions for economic load control, interruptible customers are not required to terminate use of electric energy. To the contrary, they are only required to make an economic choice. If an interruptible customer uses electricity during interruptions for economic load control, its only predicament is that it must play the charges under the interruptible rate schedule plus PP&L's estimated cost of replacement capacity and energy (Exhibit OGK 2, p. 30F).

VIII. RATE DESIGN

317. PP&L has proposed an innovative rate design for its CTC. PP&L's proposed CTC will be calculated for customers individually, that is, "customized," based upon their 1996 usage of electric energy. PP&L's customized rate design ("CRD") shifts one half of each customer's total CTCs from usage-based charges to fixed monthly CTC customer charges. PP&L St. 9, p. 5.

318. The effect of the CRD, in comparison with a more traditional usage-based (cents-per-kWh) charge are several. First, if each customer were to use during any year of the transition period ending December 31, 2005, the same amount of electric energy as it used during 1996, the customer would pay the same total amount of CTCs under both the CRD and the traditional, usage-based rate design. If, however, a customer were to use more electric energy per year during the transition period than in 1996, the customer would pay less under the CRD than under the traditional rate design. Conversely, if a customer were to use less electric energy annually during the transition period than in 1996, the customer would pay more under the CRD than under the traditional rate design.

319. PP&L's proposed CRD promotes a principal objective of the Act, which is to stimulate growth in the Pennsylvania economy. The CRD would produce rate reductions for incremental usage over 1996 levels which will likely be the case for most customers. For example, GS-1 customers will see a 16% reduction in their marginal rate; GS-3 will see a 5% reduction; LP-4 customers will experience a 6% reduction; LP-5 customers will experience a 8.5% reduction; GH-1 customers will experience an 11% reduction; and GH-2 customers will experience a 13.5% reduction on incremental usage. PP&L St. 9, p. 33.

320. The CRD will be calculated individually for each customer. First, each customer's usage during 1996 will be priced at rates established in this proceeding using a CTC calculated under traditional, usage based rates. This amount will then be divided by 12 to determine a monthly amount. One half of the monthly amount will be added to the customer charge. The remainder will be priced based on 1996 energy usage so that the annual cost of electric service will be unchanged from the annual cost for 1996. PP&L St. 10, pp. 11-12; PP&L St. 9, p. 33; PP&L Exhibit DAK 1.

321. The CRD, in addition to providing beneficial rate reductions for incremental usage, has other advantages. The CRD represents a movement toward marginal cost pricing, enabling customers to make better informed energy usage decisions. The CRD also reduces the distortive effects of stranded cost collection on energy use while maintaining some continuity with present rates by moving only half of transition charges into fixed customer charges. PP&L St. 9, p. 6.

322. OCA has opposed the CRD as causing a shift of costs from customers with increasing usage to customers with decreasing usage and as being a less efficient rate design. OCA's basis for this contention is that the marginal cost of transmission and distribution costs can exceed embedded costs. OCA St. 4, pp. 15-16.

323. Although PP&L's proposed CRD would recover less stranded cost from customers that increase energy usage, there is no prohibition against such a rate design in the Act.

324. OCA's contention, that the CRD shifts costs, is circular. It is correct only if one assumes that OCA's preferred traditional rate design is the only CTC rate design permitted under the Act; OCA's comparison of the CRD with the traditional rate design demonstrates the point that the traditional rate design and the CRD are different; it does not demonstrate that the traditional rate design is correct.

325. OCA's concern is substantially ameliorated by PP&L's third option under which all customers may choose the CTC rate design applicable to them. OCA's proposal would not promote the economy of PP&L's service territory.

326. OCA's second concern related to relative levels of incremental transmission costs and embedded costs is irrelevant. PP&L explained that it has no plans for substantial investments to expand its transmission system (Tr. 825-26).

327. PP&L presently offers a series of incentive rates that are designed, by various means, to promote economic growth in PP&L's service territory or to improve PP&L's load factor or both. These rates include riders and rate schedules and billing options. Riders include the economic development incentive ("EDI") rider, the industrial development incentive ("IDI") rider and the Competitive Rate Rider ("CRR"). Billing options available under certain rate schedules include demand free days and time of day ("TOD") billing options. Rate schedules include the Price Response Service, Rate Schedules PR-1 for firm service and PR-2 for interruptible service and Residential Thermal Storage ("RTS") service.

328. Many of the incentive rates in PP&L's presently-effective tariff are scheduled to terminate in the relatively near future. PP&L St. 11, pp. 8-13. Despite the fact that these incentive rates, as a result of prior proceedings before the Commission, are scheduled presently to terminate in the near future, PP&L has proposed to continue these rate schedules, under which certain customers receive substantial benefits. PP&L St. 11, p. 14. PP&L's proposal to continue these incentive rates is based upon its interpretation of the rate cap in Section 2804(4) of the Act. The practical effect of phasing out these incentive rates would be that affected customers would pay more for service than they would pay if the incentive rates were continued.

329. PP&L proposes to limit incentive rates to customers presently served under them and to limit the availability of incentive rates to customers who use PP&L's BUS Service for energy supplies because all of these incentive rates were designed to increase utilization of PP&L's generation resources or improve the efficiency in use of PP&L's generation resources or both. St. 11-R, pp. 3-4, 8-9. The benefits of the incentive rates are not related to PP&L's delivery service. Instead, they are designed to benefit the provider of generation services. Any incentives or discounted rates should be offered by the energy suppliers, not the delivery service supplier. Discounting delivery service rates to improve utilization of generation facilities is a relic of vertically integrated utility service and bundled rates that makes no sense once a competitive retail electric energy market is established. PP&L proposes that the incentive rates be retained only for PP&L BUS Service customers. In this way, to the extent that customers improve the load profile and utilization of BUS Service, thereby creating benefits that can be shared with other BUS customers of PP&L, PP&L will continue to make incentive rates available. Otherwise, incentive rates are not proper and should not be included in delivery service rates.

330. The Act provides that any customer returning to BUS Service is to be treated as a new customer. Because new customers are not eligible for incentive rates, returning customers similarly are not eligible for these incentive rates under Section 2807(4) of the Act.

331. PP&L proposes the following changes to existing tariff rules:

> Rule 4 is changed to indicate that the Company may upon request supply services over and above those which the Company would normally provide, if the customer agrees to pay the Company a fair and non-discriminatory price for those related services.
>
> Rule 9E was changed to indicate that the Budget Billing interest rate is changed from the number 1% per month to 1-12 of the average of 1-year Treasury Bills for the months of September, October, and November of the previous year.

332. Tariff Rule 9E was changed to conform to the amendments to the Commission's regulation at 52 Pa. Code § 56.57.

> Rule 6A has been amended to exclude fuel supply disruption from qualifying for backup power supply.

> E(5)has been added to the tariff to indicate that a customer-specific, fixed, per month CTC developed by the Company, which will equal 100 percent of the customer's estimated CTC revenue, will be applied if the customer elects to install on-site generation on or after January 1, 1999.

333. Provision E(5) was based on Section 2808(a) of the Act, which permits recovery through a non-bypassable CTC of stranded costs from customers with new on-site generation facilities. Under Section 2808(a), the CTC for such customer should be fixed and recover the customer's fully allocated share of stranded costs.

334. None of the tariff changes have been controversial.

335. Section 2804(9) of the Act requires that:

> The commission shall ensure that universal service and energy conservation policies, activities and services are appropriately funded and available in each electric distribution territory. Policies, activities and services under this paragraph shall be funded in each electric distribution territory by nonbypassable, competitively neutral cost-recovery mechanisms that fully recover the costs of universal service and energy conservation services.

336. PP&L has allocated its universal service costs on a customer basis. PP&L St. 3R, p. 36. This is the manner in which such costs have been allocated in cost of service studies accepted previously by the Commission in PP&L's most recent base-rate proceeding at Docket No. R-00943271.

337. OCA, in its St. 6-S, pp. 15-23 and OTS, in its St. 2, pp. 2-8, have raised issues concerning the manner in which rates are to be designed to recover PP&L's costs of providing universal service activities and services. OTS and OCA have recommended the universal service charges be allocated on an energy, or per kWh, basis.

338. The Act expresses strong support for continuity of rates based on each electric distribution company's most recent base-rate proceeding. *See* 66 Pa.C.S. § 2808(a).

339. PP&L's stranded costs exceed maximum CTC revenues under the rate cap during the transition period. Therefore, it is not possible to reallocate universal service costs without violating the rate cap applicable to customers that would receive a greater portion of universal service costs than would be allocated to them under PP&L's proposal.

340. OCA also provides an alternative allocator using non-production revenue as the basis for allocating universal service charges. OCA St. 6-R, pp. 20-22.

341. The OCA's alternative proposal suffers from the same deficiencies as its original proposal to allocate universal service costs based upon energy or KWh usage.

342. Under FERC Order No. 888, PP&L has proposed, subject to approval of the Commission and FERC, that its facilities operating at voltage is of 69 kV and above are transmission facilities and that facilities operating at less than 69 kV are local distribution facilities. No party produced evidence contesting PP&L's analysis.

343. PP&L's proposed unbundling of delivery charges is summarized at pp. 5-7 of PP&L St. 9-R. PP&L is proposing to unbundle its delivery charges into two principal categories, transmission and distribution. It is appropriate for the delivery charge to be divided in this manner so that retail customers can perceive correct price signals resulting from taking power at different transmission voltages under alternative supply arrangements. Further, the unbundling of delivery charges into distribution and transmission charges is required under Section 2804(3) of the Act.

344. Transmission service, however, must be further unbundled. Retail access customers of PP&L will be required to utilize transmission services from PJM under the PJM Open Access Transmission Tariff. Customers will pay unbundled charges for transmission service and related ancillary services as specified in the PJM Open Access Transmission Tariff. The services will be identified and charges therefor established by FERC. St. 12-R, pp. 8-9.

345. OCA and OTS have contended that charges for universal service should be unbundled from distribution service charges as a separate line item on bills to customers. OCA St. 6, p. 45; OTS St. 3, p. 7.

346. The OTS and OCA proposal would cause customer confusion. Charges for universal service are "non-bypassable." Section 2804(9). Unbundling services on a customer's bill is appropriate only if the customer has some choice with regard to the unbundled expense. Customers cannot decline to pay charges for universal service; customers cannot obtain universal services from any other provider, at least through the end of the transition period. Consequently, there is no point to having charges for universal service unbundled into a separate billing line item. This is particularly true given the small amount of the per customer size of the universal service charge. It is far more appropriate to bring the universal service charges to customers' attention by means of a billing message rather than as an unbundled line item on each customer's bill. PP&L St. 10-R, p. 6.

IX. PHASE-IN ISSUES

347. The Act mandates the following phase-in schedule for retail access:

> [T]he following schedule for phased implementation of retail access shall be adhered to unless a determination is made by the commission under subsection (c) [which allows for an additional six month transition period under certain circumstances]:

(1) As of January 1, 1999, a maximum of 33% of the peak load of each customer class shall have the opportunity for direct access.

(2)As of January 1, 2000, a maximum of 66% of the peak load of each customer class shall have the opportunity for direct access.

(3) As of January 1, 2001, all customers of electric distribution companies in this Commonwealth shall have the opportunity for direct access.

66 Pa.C.S. § 2806(b). The Act gives the Commission specific instructions: "The time line for the transition to and phase-in of direct access to competitive electric generation shall be in accordance with section 2806." 66 Pa.C.S. § 2804(11).

348. PP&L's proposed phase-in schedule tracks that mandated by the Act. PP&L St. 14-R, p. 4.

349. Enron, OSBA and PPLICA witnesses believe that this methodology should not apply to the selection commercial and industrial customers, based on the possibility that non-participating customers may suffer a competitive disadvantage over participating customers. Enron St. 5.0, pp. 19-20; OSBA St. 1, pp. 51-52;. PPLICA St. 1, pp. 58-59.

350. PPLICA witness Stephen Baron asserts that the most appropriate methodology for selecting industrial customers is on a first-come, first-served basis, with the customer designating a desired level of load for participation. PPLICA St. 1, pp. 58-59. If there is an over-subscription of load, Mr. Baron proposes a pro-rata reduction to each subscriber's nominated load. To alleviate any remaining competitive disadvantages, Mr. Baron proposes that PP&L begin selection for the second phase and implement such a selection process by permitting retail access for up to 66% of peak load beginning January 2, 1999. PPLICA St. 1, p. 59.

351. Enron witness Mr. Bowen advocates a similar approach. Under Enron's proposal, Enron would be willing to accept the "first through the meter" approach, where Enron would supply the first portion of the customer's electricity received in a given hour and the EDC would supply the remainder. Enron would also be willing to "follow the customer's load" and provide a fixed percentage of its customers' load throughout the day. Enron St. 5.0, p. 20.

352. OSBA witness Robert Knecht suggests a variation on PPLICA's and Enron's approach to apply to commercial customers. He suggests that minimum levels of customer participation be set for the GS rate classes for each of two phase-in years. Under Mr. Knecht's proposal, if a rate class is over-subscribed and the random drawing produces too few customers, those few customers selected should be limited in the amount of their load that is subject to competition. OSBA St. 1, p. 53.

353. The phase-in schedule established under the Act is mandatory. The Act requires the Commission to establish regulations specifying that, within each customer class, the customers that are eligible for direct access during the phase-in period shall be determined by the Commission on a first-come, first-serve basis "unless otherwise determined by the commission . . . to prevent competitive disadvantages among similarly situated customers within a customer class." 66 Pa.C.S. § 2806(4). Neither Enron, OSBA nor PPLICA has made a showing of specific competitive disadvantage sufficient to justify a departure from the statutory presumption that the phase-in period will occur in the three stages established in Section 2806 on a first-come, first-served basis. PP&L St. 14, p. 5.

354. Customers who are participating in the PP&L's pilot program can enroll in and will be selected for retail access as described above, with one exception. Customers who are participating in PP&L's pilot program, but which are not selected for the first or second phase of retail access can elect to be "grandfathered" into retail access. However, customers in the Primary and Transmission/Subtransmission groups who have load limits in the pilot program will be limited to that level of load when "grandfathered" into retail access. PP&L St. 14, pp. 4-5. No party has opposed these procedures. They are reasonable and should be approved.

X. CODE OF CONDUCT

355. The Commission is in the process of developing regulations concerning Customer Supplier Interaction at Docket No. M-00960890.F0011 and has opened a rulemaking to receive comments on the recommendations contained in the Final Report of the Competitive Safeguards Working Group ("CSWG").

356. PP&L proposes that the Code of Conduct set forth in the testimony of Robert M. Geneczko, PP&L St. 13-R, Exh. RMG-4, should govern the relationship between its EDC and EGS until regulations of general applicability are adopted.

357. The FERC required utilities in Order No. 889 to adopt standards of conduct designed to functionally separate transmission and generation functions and to prevent transmission providers from giving themselves an undue preference over their customers though the exchange of "insider" information between the company's system operators and employees of the public utility, or any affiliate, engaged in wholesale marketing functions. *See* 18 C.F.R. § 37.4. PP&L plans to extend its Order No. 889 Code of Conduct to its retail transmission operations. PP&L St. 13, p. 5.

358. PP&L's proposed Code of Conduct will govern the relationship between PP&L's Generation Supply Group and its the Electric Delivery Group.

359. PP&L's proposed Code of Conduct is set forth in PP&L Exhs. RMG 2 and RMG 4; it is discussed in PP&L St. 13-R. PP&L's proposed Code of Conduct tracks the principles adopted by the Competitive Safeguards Working Group. Specifically, the Retail Access Code of Conduct provides for:

* Open, Non-Discriminatory Access to and Pricing of Regulated Monopoly Services. PP&L Exh. RMG 2, pp. 4-5; PP&L Exh. RMG 4, pp. 1-2.

* Prohibitions on Conditioning (Tying) of Access to Monopoly Services on Purchase from Generation Supply. PP&L Exh. RMG 2, pp. 4-5; PP&L Exh. RMG 4, p. 2.

* Non-Discriminatory Dissemination of Disclosed Market and Competitively Sensitive Information. PP&L Exh. RMG 2, pp. 3-5.

* Confidentiality of Customer and Supplier Information. PP&L Exh. RMG 2, p. 4; PP&L Exh. RMG 4, p. 1.

* Segregation of Personnel and Information by Group. PP&L Exh. RMG 2, p. 1; PP&L Exh. RMG 4, p. 1.

* Restriction of Information Transfer Via Personnel Assignment. PP&L Exh. RMG 2, pp. 2-3; PP&L Exh. RMG 4, p. 1.

* Separate Cost Allocation, Books, and Records. PP&L Exh. RMG 2, p.5; PP&L Exh. RMG 3, p. 2.

* Enforcement of Employee Education in the Codes of Conduct. PP&L Exh. RMG 2, pp. 5-6; PP&L Exh. RMG 3, p. 2.

* Compliance Reporting, Auditing and Dispute Resolution. PP&L Exh. RMG 2, p. 6; PP&L Exh. RMG 3, p. 2.

360. Enron witness Mr. Dirmeier asserts that PP&L's proposed Code of Conduct would lead to customer confusion because it does not go far enough to prevent PP&L's non-regulated operations from using the name of the EDC in a manner in which customers could reasonably imply that the electric generation supply is being provided by PP&L as the EDC rather than PP&L as the electric generation supplier. Enron St. 6.0 , p. 31-33; *see also* Enron St. 6.1, pp. 1-2.

361. There will be no customer confusion under PP&L's proposal by the use of the name "PP&L Energy Plus" because as described by Mr. Geneczko, PP&L will clearly and explicitly distinguish delivery service and generation supply service as separate operations. Tr. 553.

362. The evidence shows that *prohibiting* PP&L's Generation Supply Group from using the PP&L name will lead to customer confusion and may deceive customers. Tr. 459 (8/18/97). Mandating the use of a different name would deprive consumers of the added assurance of quality and price derived from putting the parent's reputation at stake.

363. Enron witness Mr. Dirmeier asserts that if there is value in PP&L's name, then the name should not be conferred without compensation. Enron St. 6.0, pp. 28-29, Enron St. 6.1, pp. 10-11.

364. The payment of a royalty is inappropriate for several reasons. First the utility's name is not a ratepayer asset. The imposition of a royalty would constitute a requirement that a regulated company dedicate its intangible assets, for which ratepayers have never paid and do not own, to the ratepaying public. Second, a percentage royalty, which is one type of royalty that has been proposed in other jurisdictions, does not bear any relationship to costs or benefits from the association of the affiliate with the utility and would be difficult if not impossible to value.

365. PP&L's proposed Code of Conduct provides that the Electric Delivery Group will not favor the Generation Supply group in any marketing of energy supply products. In addition, PP&L witness Mr. Geneczko agreed during the hearing that PP&L's Generation Supply Group will have access to bill inserts on the same terms and conditions as other electric generation suppliers. Tr. 586.

366. As clarified by Mr. Geneczko at the hearing, PP&L's Electric Delivery group may engage in joint marketing of energy supply products with PP&L's Generation Supply group, but will only do so as long as comparable opportunities are available to other suppliers and the purpose of the joint effort is economic development. The Electric Delivery group still has an interest and community responsibility to facilitate economic development, but is indifferent, however, as to which alternate suppliers provide the energy part of the package. It will inform alternative suppliers of any such arrangements on a "rather immediate" basis, which may include posting such arrangements on OASIS. Tr. 583

367. Several intervenors suggested that PP&L should be required to offer any surplus power to Alternate Suppliers.

368. Such a requirement would be an intrusion into the competitive process that the Act has determined "will no longer be regulated..." 66 Pa. C.S. § 2802(14). Moreover, such a requirement would be beyond the Commission's jurisdiction. The sale of surplus power to Alternate Suppliers is a wholesale transaction that falls squarely within the FERC's exclusive jurisdiction under the Federal Power Act ("FPA"). Section 201 of the FPA gives the FERC plenary, exclusive and non-delegable jurisdiction over such sales. 16 U.S.C. § 824(b)(1).

369. Enron witness Mr. Dirmeier suggests the need for an internet bulletin board to document *all* information shared between the Electric Delivery Group and the Generation Supply Group.

370. This recommendation is far too broad and is not supported by any provision in the Act.

371. Enron has proposed that in the time before direct access begins to be phased in, PP&L should not be permitted to enter into "market priced" contracts unless PP&L first offers to competitive suppliers the opportunity to bid to provide service to the customer and that customers who entered into such contracts subsequent to the date on which the Act was passed to cancel such contract. Mr. Dirmeier admits that he has no information that would lead him to believe that PP&L is engaging in the behavior he would prohibit.

372. Enron's request that the Commission "open up" pre-existing market-based contract is a transparent attempt to gain Commission intervention in competitive market to favor PP&L's competitors. PP&L St. 1-R, pp. 51-52.

373. Until Commission standards for uniform, state-wide standards of conduct are adopted, PP&L's proposed Code of Conduct should govern the relationship between its Electric Delivery Group and Generation Supply Group.

374. Several intervenors have argued in this proceeding that customer metering and billing services should be unbundled from other EDC customer services in order to create an additional opportunity to provide value-added services to consumers. *See* Enron St. 4.0, p. 3.

375. The Commission concluded in the PECO Order that Section 2807 of the Act, which sets forth the duties of electric distribution companies, does not assume that any additional unbundling is required and that "EDC's continue to have the duty to provide all distribution services, including metering and billing, in compliance with existing Commission requirements." PECO Order at 138-39. The record established in this proceeding mandates the same conclusion.

376. Several intervenors have argued in this proceeding that customer metering and billing services should be unbundled from other EDC customer services in order to create an additional opportunity to provide value-added services to consumers. *See* Enron St. 4.0, p. 3. The Commission has addressed these issues through various working groups, rulemakings and Orders. Although section 2804(3) of the Act provides that "the Commission may require the unbundling of other services" in addition to basic unbundling of transmission, distribution, and generation services, the Commission concluded in the PECO Order that Section 2807 of the Act, which sets forth the duties of electric distribution companies, does not assume that any additional unbundling is required and that "EDC's continue to have the duty to provide all distribution services,

including metering and billing, in compliance with existing Commission requirements." PECO Order at 138-39.

377. As indicated the Commission's rulemaking at Docket No. L-00970120, the Commission has decided that it is unnecessary to unbundle metering as a competitive service at this time. In that rulemaking, the Commission outlined the standards and procedures to ensure that customers have real options for competitive metering while retaining all physical work related to metering as a regulated EDC function.

378. The Commission decided in the PECO Order that all customers may, in conjunction with their EGS, request use of a "qualified meter" that has been approved by the Commission based on the recommendations of a working committee composed of interested parties. The Commission will ensure that the list of qualified meters includes all meters necessary to support market services such as two-way communication, remote readings, time-of-use capability, and net metering.

379. PP&L witness Anthony M. Osmanski indicated PP&L's support for open system architecture for all metering services hardware and software. PP&L St. 21-R, p. 3. PP&L advocates the use of the standards currently being developed by the IEEE SCC-31 Standards Coordinating Committee. PP&L St. 21-R, p. 12.

380. Enron witness Raymond W. Bowen, Jr. suggests that payments received from customers by PP&L should be applied to services provided by PP&L and services provided by the supplier on a pro rata basis. Enron St. 5.0, pp. 16-1.

381. As Mr. Bowen acknowledged at the hearing, however, if payments are provided to the supplier on a pro rata basis, the amount of the EDC's non-recovery will increase. Tr. 1339-40 (8/22/97). Despite this fact, Mr. Bowen asserts that an increase in the amount of the EDC's non-recovery would not increase the EDC's cost of providing service. *Id.*

382. The Commission has already considered and rejected the pro rata payment approach advocated by Enron. *See* Final Order Re: Guidelines for Maintaining Customer Services at the Same Level of Quality Pursuant to 66 Pa.C.S. § 2807(D), and Assuring Conformance with 52 Pa. Code Chapter 56 Pursuant to 66 Pa.C.S. § 2809(E) and (F) (entered July 11, 1997). Instead, the Commission decided that the "priority" method of applying partial payments is preferable to the "prorata" method, particularly in terms of administering the process and complying with applicable Chapter 56 provisions at 52 Pa. Code §§ 56.23 and 56.24. Order at 32-33.

383. Enron witness Richard D. Tabors urges the Commission to require PP&L to make its PJM-allocated intertie benefits available to either its former retail customers who choose an alternative generation supplier or to that customer's supplier. Enron St. 8.0, p. 3.

384. It is well-established that the rates, terms and conditions of wholesales sales of power by public utilities fall squarely within the FERC's exclusive jurisdiction under the Federal Power Act ("FPA"). Section 201 of the FPA gives the FERC plenary, exclusive and non-delegable jurisdiction over such sales. 16 U.S.C. § 824(b)(1). The relief sought by Enron is beyond the scope of the PUC's jurisdiction, power and authority.

385. The Commission issued a Proposed Rulemaking Order Establishing the Standards for Changing A Customer's Electric Supplier at Docket No. L-00970121 in April 1997, which provides that a change of a customer's supplier may be initiated once the EDC has received direct oral confirmation from the customer or written evidence of the customer's consent. Under the proposed rules, "written evidence of the customer's consent" is limited to a document signed by the customer, the sole purpose of which is to initiate a change of electric suppliers.

386. Enron witness Mr. Bowen believes that the "written evidence" requirement should not require "direct" written communications from the customer through a letter of authorization or an agency agreement, nor should it require that the customer execute the document submitted to the EDC. Rather, Enron believes that

"written evidence of the customer's request" should include any document which evidences to the EDC that customer consent was received by the supplier.

387. PP&L's proposal accomplishes the same goal as the Commission's proposed regulations—to ensure that a customer consents to the switching of its generation supplier. Under PP&L's proposal, an alternative supplier may provide written notification to PP&L of a customer's decision to purchase electricity from that alternative supplier. The Company will then send the supplier's written notification to the customer and request that the customer inform the Company if any of the information is incorrect or inaccurate. If the customer does not respond, the Company will assume the supplier's notification information is correct. PP&L St. 14, p.6.

XI. Customer Education

388. As explained by PP&L's witness, Dawn G. Lennon, the key principles of PP&L's CCEP are:

* PP&L will provide clear, balanced and practical explanations of what customer choice is, how it works, what the risks and trade offs are, and how to select an electricity supplier.

* PP&L will be recognized as a consistent, reliable and trustworthy source of information on customer choice.

* PP&L will separate customer choice education efforts from sales and marketing initiatives.

* PP&L will produce customer choice educational materials which are easy to read and understand and which meet high standards of objectivity.

* PP&L will pursue partnerships with the Commission and with educational, service, and consumer organizations in the development, implementation, dissemination, and evaluation of educational materials and programs on customer choice.

* PP&L will continue its customer choice education efforts to address new needs and changes, ensure understanding, and provide ongoing support for customers.

PP&L St. 17, pp. 4-5. PP&L's CCEP includes reliance on community based organizations ("CBOs") and other shareholder groups to assist PP&L in its education efforts.

389. PP&L's Customer Choice Handbook is the centerpiece of its CCEP. It will include an overview of restructuring of the electric utility industry, an explanation of customer choice and how it works, consumer protection tips, worksheets for determining the customer's choice of suppliers and answers to important questions about the retail access market place.

390. In addition to the Handbook, PP&L will offer interactive telephone technology and presentations by customer choice educators. PP&L will sponsor a Customer Choice Education Advisory Committee composed of leaders from consumer, education and community organizations to oversee the development of customer choice educational workshops for target groups. The group will develop the details of the consumer education plan, commission the development of materials, design the methods of dissemination, analyze evaluation research on the program and ensure that PP&L's consumer education program provides balanced and unbiased knowledge to customers.

391. PP&L's CCEP is designed to be implemented on a local level by PP&L and various community based organizations. Nevertheless, PP&L will support and actively participate in a statewide effort if the Commission ultimately determines that such an effort is appropriate. As Ms. Lennon emphasized, however, a statewide effort alone cannot effectively educate customers. PP&L St. 9-R, p. 48.

392. PP&L disagrees with Enron witness Mr. Bowen's recommendation that the Commission or an independent third party under the Commission's supervision prepare and distribute educational information on a centralized basis. Enron St. 5, p. 28-29. While a Commission-led customer education program can be part of a successful education campaign, it cannot substitute for local customer education programs, which are best developed and implemented on a service territory by service territory basis.

393. PP&L has an obligation under the Act to provide balanced unbiased information from which customers can make an informed decision to exercise choice. Specifically, Section 2807(d)(2) of the Act requires each EDC to provide adequate and accurate customer information to enable customers to make informed choices. Section 2807(d)(3) of the Act further directs the Commission and each electric distribution company at to

implement a consumer education program informing customers of the changes in the electric utility industry prior to the implementation of any restructuring plan.

394. The Commission recently initiated a proceeding regarding the Creation and Implementation of a Statewide Consumer Education Program for Electric Restructuring in the Commonwealth of Pennsylvania, Docket No. M-00981036 (entered Jan. 16, 1998). As the Commission recognized, "[p]articipation in a statewide media campaign or the use of CBOs on a local level does not eliminate the requirement that the EDCs actively participate in the comprehensive consumer education program at the local level." Order at 7.

395. The most useful tools to educate are reference materials (print, audio and website) that customers can access and revisit. While the use of mass media can be an effective tool to create customer awareness, it must be followed by information such as brochures, pamphlets, direct mail and other forms of communication to reinforce the "soundbite" messages of a media campaign. The best way to educate is to mobilize and equip people in the community using community-based organizations. Tr. 2009 (8/29/97).

396. PP&L provided the OCA with a five year preliminary budget for its CCEP. PP&L St. 17-R, Exh. DGL-2. This budget will allow PP&L to meet the stated objectives of its CCEP.

397. PP&L 's CCEP is based on extensive customer research. PP&L St. 17-R, p. 5-6. Based upon input from a variety of stakeholders, including the results of an independent customer research project, PP&L is revising its Customer Choice Handbook to provide education to consumers as the phase-in of full retail competition begins. Tr. 1974.

398. Evaluation of PP&L's overall education efforts will be ongoing throughout the transition to retail competition. PP&L St. 17, p. 7. PP&L's research will continue to focus on what customers know and understand about choice, the best vehicles for obtaining this information, the most credible sources of information, the usage profile and related demographics. Customers already surveyed will continue to be surveyed and compared to new customers. PP&L will share this information with the Commission.

399. Separation of PP&L's CCEP and its communications and marketing efforts is one of the key principles of PP&L's proposal. PP&L will not use its CCEP to market competitive business products. PP&L St. 15-R, p. 22. Its education efforts will not favor one supplier of energy or capacity over another. PP&L St. 17-R, p. 22-23. Customer choice education initiatives will be managed by the Company's Services department and customer information will be managed by Corporate Communications department. PP&L's marketing activities will seek to promote products and services through either its Delivery Services & Economic Development department or through its Generation Supply Group.

400. Enron witness Mr. Bowen suggests that PP&L's name should not appear on customer education communications. Enron St. 5, p. 31.

401. This proposal should be rejected. As stated by Ms. Lennon: "To develop and disseminate consumer education materials and not to put the Company name on them would be deceptive. Consumers are entitled to know where any materials come from so they can ascertain for themselves whether or not to accept the messages in them." PP&L St. 17-R, p. 23.

XII. Universal Service

402. PP&L has been among the industry leaders in implementing programs to address customer and community needs, especially those of low-income customers. In 1996, the Company's annual funding level for universal service programs and energy conservation programs was over $7 million. The Company has reviewed its existing programs and concluded that it must continue its leadership role in this area. As outlined in the testimony, of Timothy R. Dahl, PP&L plans to increase its annual funding for universal service programs and energy conservation programs from a current level of $7 million to approximately $14.3 million by the year 2002. PP&L St. 16, p. 4.

403. Section 2802(10) of the Act provides that "the commonwealth must at a minimum, continue the protections, policies and services that now assist customers who are low-income to afford electric service." Section 2802(17) specifies that the public purpose of the programs is to be "promoted by continuing universal service and energy conservation policies, protection and services and full recovery of such costs is to be permitted through a non-bypassable rate mechanism."

404. PP&L operates five programs that provide energy assistance to low-income customers. PP&L St. 16, pp. 8-13. These programs and their current level of funding are as follows:

Customer Assistance and Referral Evaluation Sercive ("CARES")	$ 260,000
Operation HELP	$ 795,000
Winter Relief Assistance Program (WRAP)	$3,023,300
Keep Warm Plan	$1,000,000
On Track Payment Program Pilot	$2,000,000
Total	$7,078,300

405. The Company is proposing to move OnTrack from its pilot phase to a full-time program. The level of enrollment would be increased from 1,040 customers to about 10,000 customers by the year 2001. This "ramping up" of OnTrack anticipates an increase of 3,000 new participants annually. The expanded OnTrack program will target customers who have annual household income at or below 150 percent of poverty; are payment troubled; and have an overdue electric bill.

406. There are approximately 58,000 customers who may be eligible for OnTrack based on the above characteristics. PP&L St. 16, p. 19. As a result, PP&L plans to concentrate the program on low-income customers who have a demonstrated inability to pay and may be subject to service termination.

407. PP&L plans to increase its expenditures by over $7 million dollars above current funding levels. The annual level of funding for OnTrack will be expanded from $2 million to $9 million over a three-year period beginning January 1, 1999. Because PP&L will continue to solicit donations from its customers and employees, donations to Operation HELP are expected to increase annually. PP&L proposes to maintain the current level of annual funding for CARES, WRAP, and the Keep Warm Plan. PP&L St. 16, pp. 17-18.

408. In general, intervenor witnesses propose increases in funding levels for universal service and energy conservation programs, in some cases to over three times current levels, and expansion of the programs' eligibility criteria. *See, e.g.,* testimony of OCA witness Ms. Nancy Brockway; CEO witnesses Mr. Michael Karp, Mr. Craig Kuennen, and Mr. Geoffrey Crandall; and AARP witness Mr. Mark Cooper. These proposals are not supported by the Act or the evidentiary record in this case.

409. The primary intent of the universal service provisions of the Act is to ensure that current protections for low-income consumers are maintained in a competitive generation market. 66 Pa.C.S. § 2802(10).

The funding levels proposed by CEO, OCA and AARP simply were not envisioned by the Act. The intent of the Act is to restructure the electric utility industry to reflect competitive forces in the marketplace, not to implement a broad expansion of customer assistance programs.

410. As a basis for establishing the level of need for universal service and energy conservation programs, CEO's Mr. Kuennen presents information derived from the U. S. Census about poverty rates and the number of low-income households in PP&L's service area.

411. The 1990 U. S. Census data for the Company's service area show that approximately 177,000 PP&L customers are at or below 150 percent of the federal poverty guidelines. This guideline is the proposed eligibility standards for programs such as OnTrack and WRAP. However, most of these customers (approximately 70 percent) pay their electric bills and are not in arrears with PP&L. PP&L St. 16-R, p. 7.

It would be counterintuitive for the Company to encourage customers who have been paying the full amount of their electric bills to join OnTrack and begin paying only a portion of their bills.

412. 48% of the capital expenditures necessary to operate PP&L's facilities for the period 1997 through 2001 will be incurred to ensure environmental compliance. Projected capital costs after 2001 include individual environmental compliance projects that likely will be required at each facility. PP&L St. 10-R, pp. 37-38. As Mr. Krall explained. PP&L St. 10-R, p. 38):

> A significant portion of these costs are to comply with provisions of the CAAA [Clean Air Act Amendments]. These costs include Selective Catalytic Reduction and Selective Non-Catalytic Reduction systems for NOx reductions beyond those already achieved with the installation of Reasonably Available Control Technology in order to comply with the likely requirements of Title I of the CCAAA [sic]. Other costs include scrubbers to remove air toxics and fine particulates to comply with Title III of CAAA. For the years 2003, 2004, and 2005, 54% of the $429 million of capital identified, or $230 million, will be for compliance with the CAAA, alone.

413. Mr. Schoengold offers no evidence to support his claim that existing plants enjoy a competitive advantage under the current environmental regulatory scheme. PP&L St. 10-R, pp. 39-40.

414. OCA witness Ms. Brockway recommends that PP&L's annual funding for OnTrack and weatherization (WRAP, Keep Warm Plan) should be $11.7 million and $4.7 million, respectively. OCA St. 6, pp. 23, 34. Ms. Brockway's proposal represents an increase in the funding levels suggested by PP&L of 30 percent (OnTrack) and 17.5 percent (WRAP and Keep Warm Plan). AARP witness Mr. Cooper has stated that deep discounts should be made available to all low-income households. AARP St. 1, pp. 25-26. The cost of extending OnTrack credits to all of PP&L's low-income customers would be prohibitive. The average OnTrack credit is $50 per month, or $600 annually. PP&L St. 16-R, p. 9. The cost of extending the credits, as Mr. Cooper suggests, would exceed $106 million annually (177,000 x $600).

415. CEO witness Mr. Kuennen recommends that PP&L target 40 percent of low-income households (specifically, 71,000 customers) for participation in OnTrack. CEO St. 1, p. 22. OCA witness Ms. Brockway suggests that PP&L should serve 18,500 customers in OnTrack. OCA St. 6, p. 30.

416. These proposals present three significant problems: 1) it would be impractical to effectively identify, interview, and enroll tens of thousands of customers; 2) the costs would be prohibitive; and 3) good-paying customers would be encouraged not to pay under the CEO's proposal.

417. Mr. Kuennan and Ms. Brockway also advocate increased funding levels for the baseload program under WRAP. As acknowledged by Ms. Brockway, each utility should tailor its energy conservation programs to address the conditions in its own service area. Tr. 2042.

418. Given that PP&L has the highest electric heat saturation rate of the eight major Pennsylvania electric utilities, PP&L Cr. Exam. Exh. 12, PP&L has properly chosen to focus its weatherization activities on electric heat customers.

419. CEO witness Mr. Kuennan and OCA witness Ms. Brockway suggest that PP&L's current level of write-offs and credit and collection expenses associated with non-OnTrack low-income customers could be "transferred" to fund an expanded OnTrack Program rather than booking write-offs and credit and collection expenses associated with these amounts, in essence reducing its billings to these customers. CEO St. 1, p, 26; OCA St. 6, p. 26.

420. Ms. Brockway's proposal is inappropriate because it is based on the false assumption that low-income customers do not pay any portion of their bills. PP&L's experience shows that low-income customers, even those that are payment-troubled, do often pay some amount toward their bills. For example, PP&L

evaluated approximately 1,000 very low-income customers (at or below 110% of the federal poverty guidelines) and determined that even those customers pay PP&L six or seven times per year. Tr. 1948.

421. PP&L supports the OCA's recommendation to allow OnTrack customers to choose Alternative Suppliers subject to three important conditions. First, OnTrack participants who select an Alternative Supplier would be required to receive a single bill from PP&L. Second, as a condition of serving OnTrack customers, Alternative Suppliers would agree to discount the energy portion of the supply bill by a percentage equal to the overall percentage reduction established pursuant to the OnTrack program. Third, the Alternative Suppliers would agree to absorb the supply portion of the revenue shortfall that is written off monthly for OnTrack customers.

422. A key objective of OnTrack is to encourage and develop good payment habits among customers. PP&L proposes to offer one bill to OnTrack customers who choose an Alternative Supplier. A combined bill would streamline administrative procedures for the OnTrack agencies and reduce confusion for customers.

423. PP&L's average monthly electric bill for low-income, payment-troubled customers is about $88, and the average monthly electric bill for OnTrack customers is $47. In other words, the Company provides a monthly bill reduction of $41, or 53 percent. This revenue shortfall is written off monthly. PP&L St. 16-R, p. 22. PP&L recommends that Alternative Suppliers provide a pro rata reduction in energy supply charges to those OnTrack customers who choose an Alternative Supplier. Without such a pro rata reduction, the evidence shows that the amount of the monthly bill reduction could reduce the transmission and distribution portion of the customer's bill to less than zero.

424. PP&L also believes that Alternative Suppliers should share in the costs of the revenue shortfall associated with OnTrack customers. Generation accounts for approximately 25 percent of the bill, and using the above example of the $41 revenue shortfall for the average OnTrack customer, an Alternative Supplier would be responsible for $10.25 of the write-off. The remaining $30.75 would be assigned to PP&L. Because the revenue shortfall includes some generation charges, it is fair for Alternative Suppliers to assume responsibility for the portion of their the revenue shortfall. PP&L's proposal would treat both PP&L and the Alternative Supplier on the same basis while satisfying the Act's objective of providing choice to all customers in Pennsylvania. It is reasonable and should be approved.

425. Environmentalists witness Bruce E. Biewald proposes that the Commission require all retail electricity suppliers selling in Pennsylvania to disclose their fuel mix and key air and other waste emissions to consumers in the form of a label and that the tracking of transactions to support disclosure and labeling should be done by the PJM Independent System Operator ("ISO"). Environmentalists' St. 2, p. 5. OCA witness Barbara Alexander also advocates fuel mix disclosure. OCA St. 5, pp. 29-30.

426. Mr. Biewald's proposal goes beyond the Commission's recently-proposed rules on Customer Information Disclosure for Electricity Providers (52 Pa. Code, Chapter 54, Subpart A), Docket No. L-00970126. Under those rules the source of supply mix must be provided to customers upon request, upon entering into a sales agreement and whenever a significant change occurs in the terms of service. The proposed rules do not require the disclosure of environmental attributes other than fuel mix. These parties' proposals should be rejected.

XIII. Environmental Issues

427. Environmentalists witness David Schoengold proposes that the Commission adopt a plan under which all power purchased in Pennsylvania would have to come from plants meeting the latest environmental standards, Environmentalists' St. 1, p. 37, and notes that other states have enacted similar regulations based on their right to protect the health and welfare of their citizens.

428. Although the Commission retains broad authority to regulate utility service, facility and rate issues, it is the Pennsylvania Department of Environmental Protection and the U.S. Environmental Protection Agency that have the broad authority to implement and administer programs for the protection of the environment, including rules relating to air emissions. It is well established that the Commission does not possess jurisdiction over environmental issues simply because a public utility may be involved.

429. The Environmentalists' proposal is well beyond the scope of this proceeding.

430. OCA witness Ms. Brockway's suggests that PP&L provide funding of $700,000 for photovoltaic and active solar water heating pilots.

431. Neither the Act nor the Commission's Final Guidelines for Universal Service mandate such pilot programs.[5]

432. Because the annual cost savings would be very low, in light of PP&L's relatively low electric rates, the payback periods would be significant. Most consumers would not be induced to buy a system that required well over a decade to provide benefits.

433. Developing, implementing, and evaluating the OCA's proposed pilots would be time consuming and expensive for the level of benefits received., and therefore should be rejected.

DISCUSSION

I. CONTEXT OF RESTRUCTURING

This proceeding raises issues of extreme significance not only to customers and investors of utilities, as ratepayers and investors, but as citizens of the Commonwealth. The decisions made here will affect the manner in which a service essential to modern life, electricity, will be provided within a significant portion of the Commonwealth for many years into the future. In reaching these decisions, the Commission must not only balance the interests of customers and investors, but must also balance the short and long term interests of current and future customers and investors.

Fortunately, the Commission is guided in this proceeding by the General Assembly as it has spoken through the Act. As will be explained in this Brief, the Act embodies a balance between interests of customers and investors that mirrors the balance drawn by many years of

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The Commission's Final Guidelines for Universal Service expressly provide that: "Although we believe that research and development are important, we will not direct that universal service and energy conservation funds be spend for research and development. Unlike the California legislature that specifically provided funds for research and development, the Commonwealth's Act gives no direction for such expenditures." Final Guidelines at 6.

utility law and regulation. Therefore, it is important for the Commission to consider and interpret the Act in the context of the economic and legal background which led to its adoption.

A. Economic and Competitive Background

For most of this century, the provision of electric service in Pennsylvania has been extensively regulated by the PUC because the provision of that service has been considered a natural monopoly. A natural monopoly is a business which, by reasons of scale or scope, is provided more efficiently by one company than by competing companies.

There can be no dispute that electric utilities have been viewed as natural monopolies in Pennsylvania since the adoption of the Public Service Company Law of July 26, 1913, P.L. 1374 (repealed), as amended by section 4 of the Act of June 3, 1933, P.L. 1526, 66 P.S. §201-2 (repealed). The Public Service Law and its successors recognize that in exchange for a monopoly to provide service in an exclusive service territory, public utilities were both exempted from competition and obligated to provide service within that service territory. Regulation of rates and service was determined to be necessary to replace the lack of competition.

While there are many aspects to this regulation, an overriding theme has been described as the regulatory bargain or regulatory compact. The regulatory compact was described by Professor Kalt[6], as follows:

> In the pre-reform regulatory setting, utilities and the investors who provide utility capital accepted an obligation to serve all electric demand in their service territory. Pursuant to this obligation to serve, utilities accepted the obligation to incur the costs of sufficient generation and related capacity to ensure that expected demand could be satisfied, with these investment plans being subject to review and oversight by regulators and with their decisions reflected in just and reasonable rates regulators have allowed utilities to charge their customers. Investors in utility companies agreed to provide the capital necessary to make these investments under regulatory rules that subjected cost recovery to

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6 Professor Kalt is the Ford Foundation Professor of International Political Economy and the Chairman of the Economics and Quantitative methods section at the John F. Kennedy School of Government, Harvard University. He specializes in natural resources and energy policy and has published widely on matters relating to the regulation of natural gas, electricity, oil and coal markets. He has testified in numerous administrative, judicial and congressional proceedings concerning performance of the nation's energy markets.

> cost-of-service regulatory principles rather than market forces. PP&L St. 1, pp. 11-12.

Pursuant to this system of regulation, PP&L invested billions of dollars to construct generating stations to meet the reasonably projected needs of customers in its service territory. These investments have been reviewed by the Commission and have been determined to be prudent expenditures. Accordingly, under a continuation of regulated monopoly service, PP&L and its investors would have recovered both a return of, and a reasonable return on, such investments to provide service to customers. See 66 Pa.C.S. § 1301.

As explained by Professor Alfred Kahn,[7] the regulated monopoly system has served customers well for a long period of time. *See* PP&L St. 18-R, p. 21. However, changes in economic circumstances prompted a re-examination of this regulatory system:

> What has changed since then? Manifestly, the relationship between price and marginal cost, both short- and long-run: what other answer would you expect from an academic economist?
>
> The reasons for that dramatic change are familiar: First, the entry into service of long-lead-time base-load plants, constructed over a period of double-digit inflation of interest rates and construction costs and in anticipation of a continued expansion of demand at 6 to 7 percent annual rates. These developments and the abrupt deceleration of demand left utilities, particularly on the East and West coasts, with average generating costs in the range of perhaps 6 to 10 cents a kwh and, because of their excess capacity, short-run marginal costs of 1 to 2 cents. Second the collapse of fossil fuel prices in the middle 1980s, in combination with, third, the development of combined cycle gas turbine technology, which have made it possible to build 100-megawatt or smaller new plants with average costs on the order of 4 cents a kwh.
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> Fourth, the nuclear fiasco. And, fifth, PURPA, with its legacy of multi-billion dollar contractual obligations of the electric companies to buy independently generated power at rates set at

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7 Professor Kahn has been Chairman of the New York State Public Service Commission and the U.S. Civil Aeronautics Board. He is the author of the two-volume, *The Economics of Regulation*, reprinted, in 1988 by MIT Press and has written and testified extensively in the area of direct economic regulation and particularly of the public utilities.

> avoided costs estimated by regulators on the basis (among other consideration) of expectations that the price of oil would by now be nearing $100 a barrel.
>
> All these developments have combined to produce regulated rates in some regions of the country, far above both short- and long-run marginal costs. And that in turn has created irresistible temptations for sellers - including utility companies, *outside* their own franchise territories - to offer eager buyers an escape from those inflated rates. PP&L St. 18-R, pp. 21-22.

This significant metamorphosis in the economics of producing electric power led the General Assembly to conclude that generation of electricity can be provided more efficiently (at lower costs) under a competitive system.

B. Legal and Legislative Background

In adopting the Act, the General Assembly observed that "[o]ver the past 20 years, the Federal Government and State government have introduced competition in several industries that previously had been regulated as natural monopolies." 66 Pa.C.S. § 2802(1). The electric power industry did not escape this trend. In 1992, Congress passed the Energy Policy Act which specifically empowered the Federal Energy Regulatory Commission ("FERC") to order public and privately owned utilities to grant access to their transmission systems for qualified entities engaging in wholesale power transactions. 16 U.S.C. §§ 824(j),(k). The FERC dramatically expanded the availability of transmission in 1996 by issuing Order No. 888, requiring public utilities to unbundle wholesale contracts and offer open access non-discriminatory transmission service to all eligible customers — including retail customers in states implementing retail competition — while providing for the recovery of stranded costs incurred as a result of such open access. *See Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 78 FERC ¶ 61,220 (1997), *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 64,688 (1997), 81 FERC ¶ 61,248 (1997) ("Order No. 888").

C. The Electricity Generation Customer Choice and Competition Act

The Act contains declarations of policy which set forth the reasons why the General Assembly directed the restructuring of the electric industry in Pennsylvania. 66 Pa.C.S. § 2802. The Act also contains specific standards for restructuring of the electric industry. 66 Pa.C.S. § 2804. These declarations and standards set the bounds within which the restructuring of the electric industry is to be conducted and within which the issues in this proceeding must be resolved.

1. Concerns Addressed by the Act

The purpose of the Act is to mandate competition and create a transition to a competitive market for the generation of electricity. 66 Pa.C.S. § 2802(12). Within this general purpose there are several other critical concerns expressed by the General Assembly which are relevant to this proceeding.[8] The most important of these concerns are summarized here and will be referenced as applicable to specific issues later in this Brief. First and foremost, the General Assembly recognized the need for a fair transition to a competitive retail electric generation market:

> In moving toward greater competition in the electricity generation market, the Commonwealth must resolve certain transitional issues in a manner that is fair to customers, electric utilities, investors, the employees of electric utilities, local communities, non utility generators of electricity and other affected parties. 66 Pa.C.S. § 2802(1).

The Act also recognizes that electric utilities and their investors have invested billions of dollars in generating facilities, that some of these costs may not be recovered under a competitive system and that electric utilities should be permitted to recover such costs during the transition period to the extent possible within the rate cap.

> In establishing the standards for the transition to and creation of a competitive electric market, heretofore, public utilities generally have had an obligation to serve customers within their defined

[8] Provisions of the Act which are not directly relevant to this proceeding, such as licensing requirements for suppliers to protect reliability, are not summarized here.

> service territories; consistent with that obligation, have undertaken long-term investments in generation, transmission and distribution facilities in order to meet the needs of their customers; and have entered into long-term power supply agreements as required by Federal law. In many instances, these investments and agreements have created costs which may not be recoverable in a competitive market. The commission is empowered under this chapter to determine the level of transition or stranded costs for each electric utility and to provide a mechanism, the competitive transition charge, for recovery of an appropriate amount of such costs in accordance with the standards established in this chapter. 66 Pa.C.S. § 2802(15).

These principles and standards must guide our resolution and recommendation to the Commission regarding the issues in this proceeding.

Another significant concern of the General Assembly as expressed in the Act is the manner in which competition will be conducted. In this regard the Act provides that:

> This chapter requires electric utilities to unbundle their rates and services and to provide open access over their transmission and distribution systems to allow competitive suppliers to generate and sell electricity directly to consumers in this Commonwealth. *The generation of electricity will no longer be regulated as a public utility function except as otherwise provided for in this chapter.* Electric generation suppliers will be required to obtain licenses, demonstrate financial responsibility and comply with such other requirements concerning service as the commission deems necessary for the protection of the public. 66 Pa.C.S. § 2802(14) (emphasis added).

To implement this open access requirement, the Act sets forth certain standards to which the Commission must adhere:

> The commission may permit, but shall not require, an electric utility to divest itself of facilities or to reorganize its corporate structure. 66 Pa.C.S. § 2804(5).

> Consistent with the provision of section 2806, the commission shall require that a public utility that owns or operates jurisdictional transmission and distribution facilities shall provide transmission and distribution service to all retail electric customers in their service territory and to electric cooperative corporations

> and electric generation suppliers, affiliated or nonaffiliated, on rates, terms of access and conditions that are comparable to the utility's own use of its system. 66 Pa.C.S. § 2804(6).

> The commission shall require that restructuring of the electric utility industry be implemented in a manner that does not unreasonably discriminate against one customer class to the benefit of another. 66 Pa.C.S. § 2804(7).

These standards are clear. Utilities are not prohibited from continuing to provide, or compete for, electric generating customers either through affiliates or divisions but "rates and terms" of access to the transmission and distribution systems by other suppliers must be "comparable to the utility's own use." Accordingly, the implementation of such standards in a manner that provides open access to other suppliers without handicapping PP&L's efforts to sell electricity from its generating stations to retail customers is another critical issue in this proceeding.

The General Assembly also was concerned that Pennsylvania's consumers of electric power be prepared to take advantage of the benefits of competition. In addition to providing for a retail access pilot, 66 Pa.C.S. § 2806(G), the General Assembly obligated each electric distribution company to implement, in conjunction with the Commission, a consumer education program that "shall provide consumers with information necessary to help them make appropriate choices as to their electric service." 66 Pa.C.S. § 2807(d)(3).

The final major concern expressed in the Act that is relevant to this proceeding concerns the protection of customers who do not or cannot obtain service from a competitive electric supplier. In this regard, the Act contains specific policy determinations requiring continuation of programs that currently assist low-income customers, 66 Pa.C.S. § 2802(10), and other public purpose programs. 66 Pa.C.S. § 2802(17). Finally, the Act also contains requirements applicable to electric companies that are intended to provide all customers with reliable transmission and distribution service and to provide all customers with a supplier of last resort. 66 Pa.C.S. § 2802(16).

These obligations are important safeguards for the transition to competitive generation service and continue the special obligations currently held by public utilities generally. These provisions require the Commission to resolve specific issues concerning universal service and supplier of last resort service. However, the special obligations of providing continued, regulated transmission and distribution service, as well as the requirement to provide supplier of last resort service, also must be considered as they relate to other issues in this proceeding. Specifically, the interests of ratepayers must always be balanced against the requirement that the Commission foster the development of a competitive supply market while maintaining the long-term viability of the electric distribution company so that it can continue to provide regulated transmission and distribution service throughout its service territory and provide supplier of last resort services in the future.

2. Post-Restructuring Electricity Market Under the Act

The Act envisions a transition from the provision of electric generation service by a single monopoly supplier to a system under which numerous suppliers compete to sell generation to customers. Open access transmission and distribution systems will provide non-discriminatory access to all qualified suppliers. The Act also recognizes that the generation currently owned by electric utilities is the backbone of electric service in Pennsylvania and is necessary for the continued service of customers in Pennsylvania. Accordingly, the Act specifically authorizes electric utilities to maintain these facilities and use them to provide competitive service as well as supplier of last resort service to customers.

The Act recognizes that the transition to competition will require recovery of generating costs that have become stranded as a result of that transition. The recovery of stranded costs is designed to enable electric utilities to participate on reasonable terms in a competitive market while maintaining a viable company to provide transmission and distribution services and supplier of last resort service. The Act also envisions a competitive market in which programs for low-income customers are maintained and the associated costs are recovered through a universal service fund.

Finally, the Act envisions the coordination of suppliers and the electric distribution company through an Independent System Operator ("ISO") in a manner that maintains the highly reliable service presently provided by PP&L and other electric utilities. 66 Pa.C.S. § 2802(19); 66 Pa.C.S. § 2804(1).

II. LEGAL AND POLICY FOUNDATIONS OF STRANDED COST RECOVERY

A. Legal Standards

1. Statutory Provisions

The Act addresses stranded costs in three different ways. First, the "Declaration of Policy," Section 2802(15), establishes the general need for and appropriateness of recovery by electric utility companies of their stranded costs.

Second, the Act provides a general definition of "stranded costs." Section 2803 defines "stranded costs" as:

> An electric utility's known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market and which the commission determines will remain following mitigation by the electric utility.

The definition also provides a list of categories of potentially stranded costs. Third, Section 2804(14) of the Act mandates an "orderly" transition to competition designed to "provide the investors in Pennsylvania electric utilities with a fair opportunity to fully recover the amount of transition or stranded costs that the commission determines to be just and reasonable."

These provisions mandate that the Commission allow recovery of an appropriate level of stranded costs. In adopting these provisions, the General Assembly has balanced the interests of electric utilities and ratepayers in a proper manner. The Act seeks to attain, on one hand, the benefits for customers of low-cost electric generation. On the other hand, the Act permits electric utilities to collect their prudently-incurred costs which would be recoverable under the prior system of regulation but which may not be recoverable under a competitive regime.[9] This recovery of prudently-incurred stranded costs is fully consistent with general principles applicable to regulated utilities.

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[9] There is one exception to the principle that prudently-incurred stranded costs are recoverable. Recovery may be precluded by operation of the rate caps of Section 2804(4) of the Act.

2. Regulatory Compact

There can be no doubt that the Commonwealth and its regulated utilities have operated for decades under a requirement of mutual obligations regardless of whether those obligations are referred to as a "regulatory compact," "regulatory bargain," "understanding," or something else. The essence of that mutuality of obligation was that utilities had a fair opportunity to recover their prudently-incurred investments in facilities used to meet their obligation to serve all customers. See PP&L St. 1, pp. 11-12

These conclusions were reinforced by the testimony of Professor Alfred Kahn, who stated:

> I emphatically assert that there has indeed been a general understanding, over many decades, under original cost or prudent investment regulation such as has been practiced in the great majority of our jurisdictions, that the utility companies, in exchange for thoroughgoing regulation and the undertaking of costly public service responsibilities, were entitled to a reasonable opportunity to recover their prudently incurred costs . . . . PP&L St. 18-R, p. 10.

The General Assembly has expressly recognized the general principles of this bargain or understanding in the Declaration of Policy at Section 2802(15) of the Act. There, the General Assembly acknowledged the historic obligation of utilities to make substantial investments in facilities or contracts to provide safe and reliable service. The General Assembly also recognized its obligation to allow recovery of costs stranded by the change the electric generation portion of electric utilities' business from a regulated monopoly to an unregulated competitive service.

Contentions that these obligations do not exist deny the obvious. Clearly, utility investors relied on prior rules concerning the prudent investment standard and fair rates of return in forming their expectation concerning risks and returns. This conclusion is confirmed by the fact that the General Assembly believed it was necessary to adopt the Act in order to change the manner in which electric generation is regulated. Further, in the Act, the General Assembly mandated substantial proceedings, such as this one, in which a major issue is the amount of stranded costs to be recovered. PP&L St. 1-R, p. 57.[10]

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[10] The Act, in this respect, is consistent with prior law. The Commonwealth Court has ruled that denying the recovery of costs caused by a change in regulatory requirements would be fundamentally unfair under the Public Utility Code. In *Columbia Gas of Pa., Inc. v. Pa. P.U.C*, 149 Pa. Comwlth. 247, 613 A.2d 74, 80 (1992), the Commonwealth Court reversed the Commission's denial of recovery of costs

3. Federal Constitutional Doctrines

The fundamental principles of the Commonwealth's obligations to its regulated utilities are consistent with federal constitutional "due process" principles applicable to takings of utility property. PP&L's stranded costs were incurred to meet its obligation to serve customers, but these costs may not be recoverable in the competitive market for electric generation which is being created by the Act. If the Act did not provide for recovery of stranded costs, or if the Act were applied in a manner that denied recovery of stranded costs, the change in regulatory policy would violate the Fifth and Fourteenth Amendments to the United States Constitution.

The United States Supreme Court has stated that fundamental changes in regulatory rules that prevent recovery of previously approved cost would violate the fundamental due process and "takings" clauses of the Fifth and Fourteenth Amendments to the United States Constitution:[11]

> The risks a utility faces are in large part defined by the rate methodology because utilities are virtually always public monopolies dealing in an essential service, and so relatively immune to the usual market risks. Consequently, a State's decision to arbitrarily switch back and forth between methodologies in a way which required investors to bear the risk of bad investments at some times while denying them the benefit of good investment at others would raise serious constitutional questions. *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 315 (1989).

See also United States v. Winstar Corp., __ U.S. __, 116 S. Ct. 2432 (1996) (Uncompensated taking caused by changes in regulatory accounting rules that reduced the book value of assets that the savings and loan company had relied upon to meet capital reserve requirements). In the Act, the General Assembly avoided these potential constitutional issues by providing for compensation to utility companies for investments stranded by the introduction of competition to the electric generation market.

There exist a constitutional right to fair compensation to PP&L for its reasonable and prudent investments in facilities that were used and useful in providing public service. That right

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of customer arrearages (uncollectible accounts) that were created by the Commission's requiring utilities to continue to serve non-paying customers.

[11] Such an improper taking also would violate the Pennsylvania Constitution, Art. I, § 10.

to fair compensation cannot be discharged or avoided by a change in fundamental regulatory policy that destroys the value of such investments.

B. Effect on Regulated Activities

The Act will have four important effects on the regulated activities of electric utilities in Pennsylvania. First, utilities will unbundle their rates to show separately the charges for transmission, distribution and generation services, including recovery of stranded costs through the CTC. 66 Pa. C.S. § 2806(e). Second, utilities will offer open and non-discriminatory access to their transmission and distribution facilities for all qualified applicants. 66 Pa.C.S. § 2802(14). Third, utilities will continue their public purpose programs, including assistance to low-income customers. 66 Pa.C.S. § 2807(d). Fourth, utilities will offer "provider of last resort" service to any customer who elects not to choose an alternative supplier or who did not receive service from such a supplier. 66 Pa.C.S. § 2807(e).

C. Effect on Investors

The change in regulatory policy to a competitive market for electric generation reflects a fundamental change in the basic rules by which electric generation services have been provided and must allow electric utilities a fair opportunity to recover investments in facilities made uneconomic by the change in regulatory policy. Any breach of the Commonwealth's clear obligation to utility investors would be poor public policy, and would be contrary to sound economic principles, and therefore, contrary to the public's economic interest. As explained by Professor Kalt:

> Government is the promulgator and enforcer of the rules of the game. If it uses its power to alter those rules after other parties have sunk investments into the game, such action imposes costs on all of the citizens under its jurisdiction. As underdeveloped and unstable countries around the world have taught us, instability in the rules of the game by which investors must play is the recipe for failure. In a world of intense international competition and capital that can flee from policy instability, regulatory change in Pennsylvania's electric power sector that would have the effect of stranding utilities' previously incurred costs would be decidedly contrary to the public's interest in a healthy Pennsylvania economy. One immediate consequence of policy instability would

> be a higher cost of capital for firms investing in Pennsylvania, particularly transmission and distribution utilities. PP&L St. 1, pp. 13-14; *see also* PP&L St. 18-R, p. 11.

D. Mitigation

Under Section 2808(c)(4) of the Act, in determining the level of stranded costs to be recovered, the Commission is to consider the extent to which the electric utility has mitigated generation-related stranded costs. The ultimate proof of the effectiveness of PP&L's pre-restructuring mitigation is PP&L's success in controlling its rates, which the Act declares to be of "equal importance" with future efforts to mitigate stranded costs. *See* 66 Pa.C.S. § 2808(c)(5). The interplay between past efforts in controlling rates and stranded cost recover is clearly illustrated in this case. Because of PP&L's past efforts to keep rates low, the rate cap limits PP&L's ability to recover all of its stranded costs. It would, of course, be unjust and contrary to the Act to require PP&L to forego recovery of its stranded costs beyond that already denied it by application of the rate cap.

1. Pre-Restructuring Mitigation

a) PP&L's Pre-Restructuring Rates

Stranded costs related to electric generation facilities are driven by the difference between revenue requirements associated with these assets and the projected market price of electric generation. *See* Section 2803 of the Act (definition of "transition or stranded costs") and PP&L St. 2, p. 5. Consequently, a major determinant of an electric utility's stranded costs related to electric generation facilities is its level of rates for recovery of revenue requirements associated with its generation facilities.

PP&L, as a result of substantial efforts, has successfully maintained its rates at a low level. PP&L's success in keeping its rates at a low level is demonstrated from three different observations. First, as explained more fully below, PP&L's rates are low compared to rates of other electric utilities. Second, PP&L has filed relatively few base rate cases before this Commission in recent years, and those rate cases have been substantially separated in time. PP&L's two most recent base rate cases were filed on July 27, 1984 (Docket No. R-842651) and on December 30, 1994 (Docket No. R-00943271), more than a decade apart. Third, PP&L's actual, historical rates have been flat in terms of *nominal* dollars for the last ten years. PP&L Exh. SFT 3. In terms of real purchasing power, maintaining flat nominal rates for ten years is equivalent to a 25 percent rate reduction. PP&L Exh. SFT 4. By the end of the transition period, PP&L's total rates will have been flat, in nominal dollars, for 20 years. Flat nominal rates over 20 years is equivalent to a 50% reduction in rates in real terms. PP&L St. 9, p. 19, n.4.

Comparisons between PP&L's total rates and those of other electric utilities are provided at pages 16-19 of PP&L St. 9 and in PP&L Exh. SFT 2. As shown there, PECO's 1995 average rate is 9.91¢ per kWh and Duquesne Light Company's average rate is 8.92¢ per kWh. The Pennsylvania statewide average rate is 7.93¢ per kWh. PP&L's 1995 average rate of 7.21¢ per kWh is significantly lower than these other rates. In fact, PP&L's rates are now almost as low as the national average of 6.89¢ per kWh, while the spread between Pennsylvania's average rate and the national average rate has stayed relatively constant. PP&L Exh. SFT 4.

PP&L's efforts to control costs and rates have been beneficial to residential customers. PP&L's rates for residential service have dropped below the national average, while Pennsylvania's average residential rate has been well above the national average. PP&L Exh. SFT 5. These low rates have resulted from cost control efforts by PP&L. PP&L St. 2, p. 6.

b) Refinancings

PP&L has taken advantage of reductions in the cost of capital to refinance higher cost securities. These efforts are demonstrated by reference to its two most recent base rate case orders. In PP&L's 1984 rate case, *Pa. P.U.C. v. PP&L*, 59 Pa. PUC 332, 390 (1985), the Commission approved a long-term debt cost rate of 11.27 percent. In PP&L's 1994 rate case, in contrast, the Commission approved a long-term debt cost rate of 7.97 percent. *Pa. P.U.C. v. PP&L*, Docket No. R-00943271, p. 183 (September 27, 1995). During the 10½ years between rate cases, PP&L reduced its long-term debt cost rate by almost 30 percent.

PP&L was also able to reduce its cost rate of preferred stock. In its 1985 base rate case, the Commission approved a preferred stock cost rate of 9.89 percent. *Pa. P.U.C. v. PP&L*, 59 Pa. PUC at 390. By the 1994 base rate case, PP&L had reduced its preferred stock cost rate to 7.31 percent, a reduction of approximately 26 percent. *Pa. P.U.C. v. PP&L*, Docket No. R-00943271,

p. 183 (September 27, 1995). These capital cost reductions reduced PP&L's revenue requirement in its 1994 base rate case by $100 million. PP&L St. 2, pp. 6-7.

c) Operation and Maintenance Cost Reductions

After its 1985 rate case, PP&L did not file another base rate case for over ten years. PP&L St. 2, pp. 7-8. The success of PP&L's efforts is shown by a comparison of PP&L's operation and maintenance production costs (excluding fuel) over time, both in terms of nominal dollars and as adjusted for inflation. PP&L M.B at 29, PP&L St. 2, p. 7.
As on that chart, PP&L's operation and maintenance production costs have increased by only 16 percent over 10 years and, adjusted for inflation, have actually declined by 15 percent.

d) Employee Reductions

PP&L continuously has reduced costs through efficient utilization of employees. PP&L St. 2, p. 8. A total of 604 employees accepted the offer of PP&L's early retirement in 1994 who would reach age 55 by December 31, 1994.

From 1985 through 1996, PP&L reduced its employee complement by 2,005 regular full-time employees, almost 24 percent of its 1985 work force. Most reductions have occured through normal attrition, early retirement programs and voluntary severance programs.

e) Inventory Reductions

In 1991, PP&L modified its accounting for spare parts at power plants. Contemporaneously, with the Commission's approval, PP&L changed its ratemaking treatment of spare parts. Consequently, PP&L was able to pass back $94 million to customers over 5 years through a rate credit mechanism. PP&L St. 2, pp. 8-9. PP&L also reviewed its spare parts inventories to identify obsolete or excessive items and was able to write off $35 million of inventory, further mitigating PP&L's stranded costs. PP&L St. 2, p. 9.

f) Cost Effective Nuclear and Fossil Plant Operations

(1) Containment of Nuclear Generation Facility Costs

Approximately 63 percent[12] of PP&L's stranded costs relate to the Susquehanna Steam Electric Station ("Susquehanna"). PP&L has undertaken significant measures that have reduced stranded costs associated with this facility. *See generally* PP&L St. 2, pp. 9-11.

PP&L completed Susquehanna as quickly as possible in order to minimize associated capital costs. Such efforts were particularly important because while Susquehanna was under construction, inflation, short-term interest rates, and consequently, rates for the allowance for funds used during construction, were relatively high.[13] As a result of these and other measures, PP&L was able to complete construction of two large nuclear units at a total cost of approximately $3.6 billion for 1,890 megawatts of capacity or approximately $1,900 per kilowatt. Other plants in Pennsylvania and in the United States, which were constructed contemporaneously with Susquehanna, were completed at significantly higher costs per kilowatt. PP&L St. 2, p. 10.

Following completion of Susquehanna, PP&L pursued claims against the containment supplier, General Electric. PP&L settled its claims against General Electric in 1991. Because Susquehanna already was recognized in rate base and because PP&L was in the decade-long hiatus between rate cases, PP&L obtained Commission approval to refund the jurisdictional amount of the net settlement proceeds to customers through a special rate credit mechanism that returned $55 million to customers. PP&L St. 2, p. 10.

In addition, PP&L has operated Susquehanna at high a capacity factor. Because nuclear power plants have high capital costs, but low fuel costs, their efficiency depends upon a high capacity factor — the more a nuclear generating plant operates, the more fuel savings it can provide. Susquehanna's excellent operating record has reduced PP&L's energy costs and customers' rates. Further, because this historical operating record has been projected to continue in the future, it reduces PP&L's stranded costs in this proceeding. PP&L St. 2, pp. 10-11. More recently, between 1991 and 1995, PP&L spent $45 million to upgrade Susquehanna's capacity by 90 megawatts, or $500 per kilowatt, producing additional energy cost savings for customers.

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12 $2,852 million ÷ $4,499 million. See PP&L Exh. JRS 1A.

13 Susquehanna Unit 1 commenced commercial operation on June 8, 1983, and Susquehanna Unit 2 commenced commercial operation on February 12, 1985. *Pa. P.U.C. v. PP&L*, 59 Pa. PUC 332, 337, n.1 (1985). For measures of inflation and short term interest rates, see, *e.g.*, OTS Exh. SR-3, Schedule 4.

(2) Savings in Fossil Plant Operations

PP&L has operated its fossil fuel generating plants efficiently and has made substantial expenditures to assure the continued viability of low cost, coal-fired generating stations. These generating stations benefit customers through low fuel costs and increased interchange sales, which both lower retail rates. PP&L St. 2, p. 11.

PP&L also has invested to improve the efficiency of other fossil fuel plants. For example, PP&L converted its Martins Creek Units 3 and 4 to gas/oil dual fuel capability. PP&L now can burn gas or oil, whichever costs less, at these units, which makes them more cost effective. PP&L St. 2, p. 11.

g) Non-Utility Generator Contract Cost Reductions

Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), PP&L was compelled to enter into long-term supply contracts with NUGs. Rates in these agreements were based upon future market prices of fuels, which were projected at the time the contracts were executed. At that time, the price of oil was expected by now to be nearing $100 a barrel. PP&L St. 18-R, p. 22. NUG contract prices have turned out to be greater than PP&L's avoided costs of replacement generation or purchased power. In order to reduce the level of stranded costs resulting from uneconomic NUG contracts, PP&L has undertaken several actions which have reduced stranded costs by $100 million.

h) Economic Development Initiatives

As explained previously, the essence of pre-restructuring mitigation is keeping pre-restructuring rates low. There are two sides to keeping rates low. One side is cost containment, which has been explained above. The other side is increasing sales and revenues so that fixed costs can be recovered over a greater number of billing units, thereby decreasing the average cost per unit.

On the sales side of the equation, PP&L has promoted economic development in order to retain existing and to attract new industrial load. PP&L has been "prospecting" nationally to attract businesses to its service territory. PP&L has worked with regional economical development organizations and has provided economic development loans in order to attract industrial load and jobs to its service territory. PP&L has adopted specific tariff provisions and rates, subject to the Commission's approval, to promote economic development, including the interruptible service rates, Economic Development Initiative ("EDI") credits, Industrial Development Initiative ("IDI") credits and Demand Free Days. PP&L St. 2, p. 13. These initiatives have helped PP&L avoid rate increases and have generated thousands of new jobs in PP&L's service territory. PP&L St. 2, p. 13-14.

2. Post-Restructuring Mitigation

a) Foregone Recovery Under the Rate Cap

PP&L has demonstrated, in this proceeding, stranded costs of $4.5 billion. PP&L St. 2, p. 18. PP&L has proposed in this proceeding, however, a CTC that will recover only $4.0 billion, resulting in a shortfall of $500 million. PP&L St. 10-R, p. 3. Under PP&L's proposal, its shareholders will bear an estimated $500 million of stranded costs.

Moreover, the CTC revenue shortfall is based upon projected future electric generation market prices. However, PP&L's filing assumes that most of its fixed costs will be recovered as a result of future electricity market price and sales increases. If PP&L's projections overstate actual future market prices, PP&L's total revenues will decrease and its unrecovered stranded costs will increase commensurately.

b) Depreciation Swap

Pursuant to Section 2808(c)(4)(iii) of the Act, one of the mitigation steps that electric utilities are to consider is reallocating depreciation reserves from transmission and distribution plant accounts to generation accounts. In its filing, PP&L has proposed to transfer $205 million of its depreciation reserve related to transmission and distribution plant to the accumulated reserve for depreciation associated with Susquehanna. The transfer of the depreciation reserve, together with the changes in the reserve for deferred income taxes, would reduce PP&L's stranded costs by $317 million. PP&L St. 2, p. 17.

This proposal arises from PP&L's 1994 base rate filing in which the Commission granted PP&L's request to extend the regulatory service lives of its transmission and distribution plant. If PP&L had used these longer lives commencing at the time that present transmission and distribution facilities originally were placed into service, the accumulated depreciation reserve for these facilities would have been $205 million less than the level currently recorded on PP&L's books and records. It was this change in depreciation lives that made the $205 million of depreciation reserve available to be transferred to generation plant accounts.

Despite the fact that the "depreciation swap" would decrease stranded costs, OCA, the Department of Defense and the Environmentalists have opposed the proposed transfer of the depreciation reserves. They have raised four purported grounds for rejecting PP&L's proposal. None of these grounds have validity.

First, there is no cost shifting between rate classes at the retail jurisdictional level because PP&L's unbundled rates were derived from its cost of service study approved in the 1995 base rate case, which was not modified to reflect the swap of the depreciation reserve. PP&L St. 3-R, pp. 12-13. PP&L's proposal will not result in cost shifting between federal and state jurisdictions. Any possible cost shifting will be avoided by PP&L's creation of a regulatory asset applicable to the transmission and distribution functions which equals the allocated depreciation reserve to be transferred. Under this proposal, the net decrease to the depreciation reserve for the Pennsylvania jurisdictional portion of the transmission and distribution function will equal the Pennsylvania jurisdictional portion of the increase to the depreciation reserve for the nuclear generation function.

Second, it is difficult to imagine that the small change in rates resulting from the depreciation swap would affect customers' usage patterns. PP&L St. 8-R, p. 53. Further, one purpose of the Act is to achieve lower rates to improve the economy of Pennsylvania. *See generally*, Section 2802. The Act encourages mitigation of stranded costs for the purpose of reducing electric utilities' CTCs, thereby lowering rates. Arguments against reducing rates are contrary to the express purpose of the Act.

Third, customers are protected from overrecovery by electric distribution companies of transmission and distribution costs through the applicable rate cap. Consequently, customers cannot be harmed by a reduction in PP&L's stranded costs. Further, the "depreciation swap" is one of the mitigation procedures expressly contemplated in Section 2808(c)(4)(iii) of the Act. PP&L St. 8-R, p. 53.

PP&L's proposal to transfer a portion of the depreciation reserve applicable to its transmission and distribution facilities to nuclear generation facilities, in order to reduce stranded costs, should be recognized as appropriate mitigation.[14]

c) Operation and Maintenance and Administrative and General Cost Reductions

In computing stranded costs, PP&L has projected approximately $513 million in reductions to future operation and maintenance and administrative and general costs. PP&L St. 2, p. 16 These projections reflect a continued commitment to cost containment and an estimate of the reductions that PP&L expects to achieve. However, if PP&L is unable to achieve the projected $513 million of future cost reductions, PP&L and its investors will bear the costs that PP&L is unable to avoid.

d) Treatment of the 1999 Depreciation Change

In its most recent base rate case, PP&L proposed to modify the method by which it accrues depreciation on Susquehanna. PP&L had used a modified sinking fund method to moderate rate increases associated with placing these units into rate base. PP&L proposed, commencing January 1, 1999, to switch to a straight line method of depreciation, under which it would experience a reduction in its annual depreciation accrual of an estimated $70 million. In conjunction with its proposal to change the depreciation method, PP&L proposed also to reduce base rates effective January 1, 1999, to reflect the effects of this switch in depreciation method. The Commission approved PP&L's proposal. *Pa. P.U.C. v. PP&L*, Docket No. R-00943271, pp. 112-13 (September 27, 1995).

As a result of the fundamental changes in regulatory policy under the Act which imposes rate caps on PP&L from January 1, 1997 through 2005, such a rate reduction is no longer appropriate. PP&L St. 10, pp. 9-10. Under prior rate regulation, PP&L could have filed base

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[14] PP&L notes that the PUC rejected a proposed depreciation swap in PECO's Restructuring Proceeding. PECO Order, p. 97. That adjustment is *not* the same adjustment proposed by PP&L in this case. PP&L's excess transmission and distribution depreciation reserve resulted from a new study extending the lives of those assets which was reviewed and approved by the PUC in PP&L's 1995 base rate case. The reduced depreciation expense resulting from this study therefore has already been flowed through to customers through lower rates.

rate cases in 1997, 1998 or anytime thereafter in order to recover increased costs of providing electric service. Therefore, it was reasonable to flow through to ratepayers the effects of the change in depreciation method. Under the Act, however, PP&L cannot increase base rates commencing January 1, 1997 and for nine years thereafter. Under these circumstances, it would be far more appropriate for the Commission to permit PP&L to use the reduction in annual Susquehanna depreciation expense to accelerate amortization of regulatory assets and post-transition NUG costs. PP&L St. 2, pp. 18-19. Pursuant to the Act's policy to mitigate stranded costs, the reduction in the annual depreciation accrual for Susquehanna should be used to mitigate stranded costs, as proposed by PP&L.

e) Reduction in Planned Capital Expenditures

In late 1995, PP&L announced plans to reduce capital expenditures over a 5-year period by \$671 million. Of this total, \$486 million represented reductions in plant expenditures for fossil generating units. Reductions in capital investment in generating facilities mitigates PP&L's stranded costs. PP&L St. 2, p. 9.

f) OCA's Criticisms of PP&L's Mitigation Efforts Are Meritless

Although OCA makes several vague criticisms of PP&L's mitigation of stranded costs, only two items are specific. OCA contends that PP&L has not recognized productivity gains in calculating stranded costs and that PP&L has not recognized the full value of its own assets. These specific adjustments are addressed in detail in Section V. D. As explained therein, these adjustments are without merit.

E. Allocation of Stranded Costs between PP&L and Ratepayers

Several parties in this proceeding have suggested that stranded costs should be "shared" between PP&L and its ratepayers by various artificial and arbitrary means. *See, e.g.,* OCA St. 1, pp. 29-32; OTS St. 1, pp. 20-21; PPLICA St. 1, pp. 15-22. In making these contentions, these parties misapply Section 2804(13) of the Act, which provides as follows:

> Consistent with Section 2808 (relating to competitive transition charges), the commission has the power and duty to approve a competitive transition charge for the recovery of transition or

> stranded costs it determines to be just and reasonable to recover from ratepayers.

It is clear that parties misconstrue and misapply the term "just and reasonable."

Virtually all of PP&L's plant investments have been reviewed by the Commission in prior base rate cases and included in rate base as prudently-incurred and used or useful in the public service. PP&L's most recent base rate case was based upon a future test year ended September 30, 1995. *Pa. P.U.C. v. PP&L*, Docket No. R-00943271, p. 1 (September 27, 1995). No generation units have been placed in service since this test year. Only the relatively minor plant additions placed into service since September 30, 1995, could have been the subject of prudence contentions in this proceeding, and no such contentions have been raised. Therefore, all of PP&L's rate base and operating expenses are "just and reasonable" as that term is used in Section 1301 of the Public Utility Code, 66 Pa.C.S. § 1301, to establish a utility's rates. It follows that PP&L's stranded costs arise from PP&L's present "just and reasonable" rates. The Act should be interpreted to allow recovery of such stranded costs arising from investments and expenses that were determined to be proper in setting present rates.

In the PECO Order, the Commission ruled that in determining a just and reasonable level of stranded cost recovery under Section 2808(c)(3), the Commission must consider whether "the utility's efforts to mitigate stranded investment have been "reasonable under all of the circumstances[.]" PECO Order, p. 67 (citing Section 2808(c)(4)). The Commission noted that Section 2808(c)(4) requires "equal consideration" of the utility's "efforts undertaken over time . . to reduce or moderate rate levels." As noted above, with some of the lowest rates in the state, PP&L has satisfied this standard. Indeed, it is application of the rate cap at these low rates that prevents PP&L from recovering up to $500 million in stranded costs.

Parties in prior utility base rate proceedings have contended that certain otherwise "just and reasonable" expenses of public utilities should be "shared" between ratepayers and the utility on policy grounds similar to contentions raised by various parties in this proceeding. Such contentions have been uniformly rejected by Pennsylvania appellate courts. *See, e.g., Butler Township Water Co. v. Pa. P.U.C.*, 81 Pa. Comwlth. 40, 473 A.2d 219, 221-22 (1984); *T.W. Phillips Gas & Oil Co. v. Pa. P.U.C.*, 81 Pa. Comwlth. 205, 474 A.2d 355, 366-67 (1984). Similarly, the sharing proposals should be rejected in this proceeding.

Significantly, when the General Assembly wishes to mandate "sharing" mechanisms, it knows how to do so. When considering electric generation units with excess capacity that is not used or useful in the public service or electric generating units which experience excessive outages, the General Assembly has set forth procedures for such determinations and specified the sharing mechanisms that the Commission is authorized to employ. *See* 66 Pa.C.S. § 1322 (as to excessive outages) and 66 Pa.C.S. § 1323 (as to excess capacity). The Act, in contrast, contains no such provisions.

Moreover, the OCA's proposed stranded cost proposal would have a devastating impact on PP&L. This analysis is provided in PP&L St. 8-R, pp. 18-29.[15]

OCA's proposed level of stranded costs is unjustified. Similarily that proposed by OTS in its Main Brief at pages 7-14 is unfounded

PP&L has proposed to recover 100% of its stranded costs through a CTC per Kwh from each customer. OTS witness Mr. Gruber testified that PP&L should not be allowed to recover 100% of its stranded costs, and has recommended that the Commission order the Company to share stranded costs associated with net generating plant between the ratepayer and the stockholder on a 90%/10% split.

OTS believes that there should be a sharing of the stranded costs between the ratepayers and the stockholders of the Company because of the "intent" of stranded costs. OTS contends that the Commission should provide some incentive for the utility to mitigate stranded costs through the use of a sharing mechanism. OTS argues, but we disagree that it is clear that the inclusion of a company's total stranded costs would reward those utilities who in the past have made less cost efficient judgments in their choices and construction of generation capacity. This is a separate issue.

We disagree with OTS witness Mr. Gruber's proposal that the Commission should order a sharing of stranded costs, "because if you do not share the costs, the Commission will be penalizing the efficient utility by allowing the inefficient utility to recover all of its

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15 In its surrebuttal testimony, OCA increased its stranded cost allowance to approximately $1.0 billion. OCA St. 1-S, p. 7. This small increase has no material effect on the financial results outlined below. Tr. 1543-45 (8/26/97).

inefficiencies in the Competitive Transition Charge (CTC)." The Act is not about micro-managing the competition.

For purposes of this restructuring filing, the OTS has proposed a 10% sharing for the stockholder of the Company to absorb.

OTS argues that the precedence for this 90%/10% (Ratepayer/Stockholder) Split from the instance when the natural gas local distribution companies (LDCs) were faced with having to pay "take or pay" buyout costs of long term gas supply contracts, and the Commission approved a 90%/10% sharing between ratepayer and stockholder as a reasonable solution. The "take or pay" issue is not a "stranded cost" issue. As stated above had the legislature wanted sharing it would have been provided.

We reject OTS' request that the Commission employ a 90%/10% (Ratepayer/Stockholder) Sharing of stranded costs. (See OTS Exhibit No. 1, Schedule 4)

III. STRANDED COST CALCULATION METHODOLOGY

INTRODUCTION

The Act generally identifies three categories of stranded costs: (1) regulatory assets and other deferred charges, the unfunded portion of nuclear plant decommissioning costs, and cost obligations under contracts with NUGs; (2) costs related to the cancellation, buyout, buydown or renegotiation of NUG power supply contracts; and (3) other generation-related expenses, principally plant and fossil decommissioning costs. 66 Pa.C.S. § 2803. As defined in the Act, stranded costs are the present value of net generation-related costs that would be recoverable under traditional cost-of-service regulation, but which may not be recoverable in a competitive market and which remain after mitigation efforts. 66 Pa.C.S. § 2803

A. PP&L's Calculation Of Stranded Costs

PP&L's Restructuring Plan filing includes expenses from each of the categories identified by the Act. PP&L St. 8, p. 3. For stranded cost calculation purposes, PP&L divided its claimed expenses into four categories: (1) nuclear generation; (2) fossil generation; (3) NUGs; and (4) generation-related regulatory assets. Utilizing a regulatory or revenue requirement methodology (the "regulatory method"), PP&L determined that it has approximately $4.5 billion in stranded costs after mitigation.[16] Table B to PP&L's M.B. provides a summary of PP&L's $4.5 billion stranded cost claim under the regulatory method

The OCA and PPLICA oppose the Company's method of calculating stranded costs related to generating plant, and recommend that the Commission adopt the asset value method proposed by PECO in its Restructuring Plan proceeding (Docket No. R-00973953). OCA St. 1, p. 14; PPLICA St. 2, p. 10 (Table C to PP&L's M.B. provides a calculation of stranded costs using the asset value method) We find PP&L's regulatory method is appropriate and fully consistent with the Act and recommmend its adoption.

B. The Regulatory Method vs. The Asset Value Method

The regulatory method of calculating nuclear and fossil generating plant stranded costs, proposed by PP&L, compares the annual cost-of-service revenue requirements for each generating plant to the projected annual revenues each plant would receive from the sale of its output using market-based prices for each year beginning January 1, 1999, to the end of its remaining service life. PP&L St. 8, p. 4. The Company applied a PUC-jurisdictional percentage to the annual excess or deficiency, and discounted the resulting stream of annual excesses or deficiencies to present value at January 1, 1999 using a discount rate of 7.92%, which is PP&L's after-tax weighted average cost of capital PP&L St. 8, p. 4; PP&L Exh. JRS 1, p. 1.

In contrast, the asset value method compares the present value of revenues, less cash expenses, that could be earned from generating facilities in a competitive market, with the sum of the current book value of generation and regulatory assets. PP&L St. 8-R, p. 7. Under the asset value method, the difference between this net market value and current book value equals stranded cost.

We favored the regulatory method for the following reasons:

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[16] In its initial filing, PP&L estimated that it had approximately $4.6 billion in stranded costs. PP&L Exh. JRS 1, p. 1. The Company subsequently revised its claim to reflect an error in its original calculation. The Company's final stranded cost claim is $4,499,922,000. *See* PP&L M.B., Tables B and C.

First, the regulatory method is simple to understand and to apply because it essentially uses a series of future test years; all revenues and expenses are reflected in the time period in which they occur.

Second, a variety of conceptual issues arising under the regulatory method, previously have been resolved by the Commission under traditional cost-of-service regulation. Thus, allowing the Commission to apply existing rules and accepted assumptions in calculating stranded costs.

Third, the regulatory method is fully consistent with the Act. Specifically, Section 2803 of the defines stranded costs as the "known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, *which traditionally would be recoverable* in a competitive generation market and which the commission determines will remain following mitigation by the electric utility." 66 Pa.C.S. § 2803 (emphasis added). Under traditional rate regulation, utilities are allowed a fair opportunity to recover their revenue requirement. Consequently, revenue requirement is the proper starting point for the determination of stranded costs of generating plants. The Act defines stranded costs based on a comparison of revenue requirements under traditional regulation with revenues projected in a competitive market.

Fourth, the regulatory method prevents an electric utility from deriving an unfair benefit from the transition to competition.. At most, a utility may only receive the level of revenues that it would have received under current Commission-approved rates.

Fifth, the regulatory method takes into account the effects of book value on revenue requirements year by year.

PP&L St. 8-R, pp. 5-7; PP&L St. 19-R, pp. 15-16. See, PP&L M.B. at 44.

Application of the asset value approach presents numerous problems and complexities. The result is a mixed, hybrid approach which introduces substantial (and needless) complexity and causes serious errors in the OCA and PPLICA presentations.[17]

OCA and PPLICA rely on the Commission's recent Order in the PECO Restructuring proceeding to support their recommendation to use the asset value methodology in this case. PP&L respectfully submits and we agree that the PECO Order does not support the use of the asset value method in this case. First, it is important to note that, *when properly applied, both the regulatory and asset value methods should produce comparable results because they theoretically measure the same costs.* PP&L St. 19-R, pp. 9-14. As explained by Mr. Guth, the two methods use the same inputs, with one exception. The asset value method utilizes book value, while the regulatory method utilizes the sum of revenue related to annual return on capital and revenue requirements for income taxes.

Second, in our view, the PECO Order should not be interpreted as supporting the use of the asset value method over PP&L's proposed regulatory method. In fact, because none of the parties in the PECO Restructuring proceeding proposed the regulatory method to calculate stranded costs, the regulatory method simply was not at issue in the PECO Restructuring case.

Third, the OCA and PPLICA stranded cost models are not in the record in this case.

IV. MARKET PRICE OF ELECTRICITY

PP&L used the forecast of prospective market electricity prices to develop market revenues for each plant on an annual basis. The market revenues were then subtracted from revenue under regulation to determine the stranded costs associated with PP&L's generating plants. See PP&L Main Brief pp. 48-87 ,pp. 87-129.

The prospective market prices for electricity are comprised of the price of capacity and the price of energy. Customers will pay for capacity (i.e. the right to draw upon PP&L's generating assets when needed) and for electric energy as they use it. Both energy and capacity prices are important in evaluating the competitive market value of PP&L's generating assets.

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[17] Examples of such errors include the calculation of Taxes Recoverable. *See* PP&L M.B.Section V.D.6.

However, energy prices are far more significant because they will represent approximately 90% of revenues received for electricity. PP&L Main Brief at 49.

In this proceeding there are three (3) estimates of prospective market prices for electricity (PP&L witness S. Jones, OCA witness D. Smith and PPLICA witness R. Falkenberg).[18] Each witness has provided an estimate of future capacity and energy prices. We find that PP&L's estimates reflect reasonable and consistent assumptions concerning future fuel prices and inflation as well as a tightening of the available capacity early in the next century.[19]

In general, witnesses for OCA and PPLICA estimate that market prices for electricity will rise sharply in the future. Their forecasts of increasing prices appear to be contrary to the actual results of deregulation in other areas. Simply stated, deregulation and competition produce lower prices. This is what was intended by the General Assembly. 66 Pa.C.S. §§ 2804(4) and (5). This is what has been experienced in deregulation of other industries such as airlines and trucking. PP&L St. 7-R, pp. 23-24; PP&L Exh. STJ 9. Overstated market prices ignore the fundamentals of competition, grossly overstate the future market prices for electricity and understate PP&L's stranded costs of generation.

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[18] Mr. Smith and Mr. Falkenberg presented market price projections in the PECO Restructuring proceeding, along with three witnesses on behalf of PECO. Dr. Jones did not testify in that proceeding. The Commission concluded that Mr. Smith's analysis was ". . . the most reasonable determination of future market value in the record . . . ." It did note that it found no single proposal in that proceeding "completely convincing." PECO Order, p. 88. The Commission must make a determination of the market price projections based on the record in this case. As explained hereinafter, PP&L has raised numerous issues concerning Mr. Smith's presentation which were not presented, and, therefore, not resolved in the PECO Restructuring proceeding.

[19] PP&L's estimates were prepared by Dr. Scott T. Jones, CEO of the Economics Resources Group. Unlike the other witnesses on this issue, Dr. Jones has extensive experience in the energy industry and in projecting energy and fossil fuel prices. He was Director of Energy Studies for Atlantic Richfield Company from 1980-1985 and has provided consulting services to the oil and gas industry for more than 10 years. He has studied projections of fuel prices and the relationship of various fossil fuel prices, published articles on such issues and testified in numerous proceedings on fuel prices. PP&L Exh. STJ 1.

A. Relevant Market for Energy

In determining the capacity and energy prices that will be paid to PP&L, it is necessary to first determine the relevant market for sale of electricity and the likely sources of competition. PP&L witness Dr. Jones defined the supply side of the market as the generation sources in PJM and those available to serve customers in PJM. This definition includes both power sources in PJM as well as energy and capacity that can be delivered to PJM. PP&L St. 7, p. 9. The demand side of the market for generation includes all customers in PJM as well as those with access to electricity that can be delivered over lines within and connected to PJM. PP&L St. No. 7, p. 9.

B. Price of Capacity

1. Methodology

Dr. Jones estimated future capacity prices by beginning with current contracts for sale of capacity held by PP&L. PP&L currently makes short-term or spot capacity sales and makes sales in the forward market. PP&L St. 7, p. 45.

In forecasting future capacity prices Dr. Jones projected that capacity prices would rise sharply as PJM moved from the current state of capacity excess to a balance of demand for, and supply of, capacity which corresponds to an expected elimination of the capacity excess in PJM.. See, PP&L Exhibit STJ 8, PP&L St. No. 7, pp. 45-46.

In contrast, OCA witness Mr. Smith projects continually increasing capacity prices from 1999 to 2015 based upon the carrying cost of new "peaking" capacity in 2001. OCA St. 2, p. 18, OCA Exhs. DCS 7, DCS 10. PPLICA witness Mr. Falkenberg projects generally rising capacity prices with a two year reduction in prices following tightening of the capacity market in 2001. PPLICA St. No. 2, p. 63, PPLICA Exh. RJF 9b.

The main criticizism of Dr. Jones' estimates of market capacity prices are that they are insufficient to encourage investors to install new capacity when needed. PP&L argues that these allegations have been demonstrated to be based upon errors of analysis and incorrect assumptions. PP&L Main Brief pp. 51-55.

2. Sufficiency of Market Capacity Prices to Support Additions of New Capacity

OCA, PPLICA and OSBA challenged Dr. Jones' forecast of market capacity prices as insufficient to support addition of new capacity. OCA St. 2, pp. 12-17; PPLICA St. 2, pp. 35-40; OSBA St. 1, pp. 32-34.. Dr. Jones refuted such analysis in his rebuttal testimony. PP&L St. 7-R, pp. 68-85; PP&L Exhs. STJ 28 and 28a. OCA and PPLICA responded to Dr. Jones in their surrebuttal testimony. OCA St. 2-S, pp. 10-20; PPLICA St. 2-S, pp. 13-33. Dr. Jones responded in rejoinder. Tr. 1385-86, 1391-96 (8/25/97); PP&L Exhs. STJ 28R, STJ 28aR and STJ 28bR.

PP&L argues and we agree that this "issue" is a "tempest in a teapot".See, PP&L revised Exh. Nos. STJ 28 R, STJ 28aR and STJ 28bR wherein Dr. Jones addresses the cost of the new unit, costs of other facilities such as land and pipelines to serve the unit, and the heat rate (amount of BTUs needed to produce a Kwh of electric energy) at which the unit can be expected to operate. PP&L Main Brief pp. 52-54.

We find that the contentions of various parties that Dr. Jones' market capacity prices are "insufficient" to support additions of new capacity are unsupported by the record. PP&L's analysis demonstrates that its forecasted prices are sufficient to support such additions at even today's costs and heat rates. As unit costs decrease and/or heat rates improve (less fuel to produce each Kwh) the rates of return produced by new units will be even higher.[20] Accordingly we find that the market capacity prices forecasted by Dr. Jones are demonstrated to be reasonable.

OCA's and PPLICA's witnesses ignore the effects of competition in lowering prices and provide no real-world basis to support their projected capacity prices. In contrast, PP&L's prices are based upon current contracts and have been demonstrated to produce returns that are sufficient to install new generation. For these reasons, PP&L's capacity prices are the only capacity prices that are justified by the record in this proceeding, and are accepted. As shown in Table D to PP&L's Main Brief, the use of OCA's higher capacity prices would increase projected market value by $38.446 million and reduce PP&L's stranded costs by an equal amount.

[20] The calculations in PP&L Exhibit STJ 32 are based upon a heat rate of 7000 Btu/Kwh, which is very conservative. Mr. Smith estimated a future heat rate of 6700 Btu/Kwh which, if used in PP&L Exh. STJ 32, would increase rates of return even further because the unit would consume less fuel per Kwh produced. Tr. 1395 (8/25/97).

C. Price of Energy

Three witnesses have projected energy prices in this proceeding. Each witness has used a model to estimate future energy prices. The principal inputs of these models are fuel prices, operation and maintenance expenses for each generating unit, inflation, efficiency of each generating unit, customer demands for energy and imports of energy from outside the PJM pool. Accordingly, one of the primary controversies in this proceeding is the appropriateness and reasonableness of the inputs to the models. Before addressing those inputs, issues concerning the appropriate model to employ must be resolved.

1. Choice and Use of Models

Each of the witnesses agrees that the model should be designed to determine the marginal cost of the last generating unit dispatched to PJM each hour. PP&L witness Dr. Jones explained the theory of his model as follows:

> Suppliers, like PP&L, seeking to supply load in the PJM-ISO region will bid prices into the regional capacity and hourly energy markets. These bids represent the prices at which generators are willing to supply electric generation services. If they are called upon in any hour, generators will behave as "price-takers", receiving a market price for electricity they generate. In competitive markets, where suppliers receive the market clearing price, producers will tend to bid their generation at its marginal cost. The variable costs of the last generation facility dispatched will determine price, rather than sunk investment costs. In such a system, competition is fostered through the activities of each generator, acting in its own self-interest, which together produce electricity at the lowest possible cost. PP&L St. 7, pp. 5-6.

It is to be noted that every generating unit operating in a given hour will receive the price paid for energy from the marginal or highest cost unit dispatched. In this way, all units which run in a given hour and have costs less than the marginal cost unit will receive a price which exceeds the variable costs of running such units. Accordingly, these units will recover a portion of their fixed costs.

The price of energy on an hourly basis is converted to hourly and annual revenues for each generating unit. The excess, if any, of revenues over variable costs is available to cover the fixed costs, including return, of such generation stations. To the extent that market prices are not sufficient to produce revenues to cover all fixed costs, there are stranded investments in generation.

While the theoretical approach to the models used by each witness is essentially the same, there are differences in the way that each model operates which create differences in the resulting market prices that are not accounted for by differing input assumptions. See PP&L Main Brief pp. 55-87.

a) PP&L's EGEAS Model Produces the Most Realistic and Reliable Results

Each of the witnesses testifying as to energy prices used a different model to project such prices. Dr. Jones, testifying for PP&L, used the EGEAS (Economic Generation Expansion Analysis System) model. Dr. Jones explained how the EGEAS model operates:

> EGEAS is an economic dispatch model designed primarily for long-term system planning. As its name implies, the primary purpose of the model is to find the best possible combination of generation resources for meeting system load in the short run and in the long run. In the short run, EGEAS is a production cost model, dispatching units to meet demand levels in each hour of the year. Over the long run, the model adds capacity to the existing system to meet reliability constraints. Depending upon the economics at that point in time a new unit will be added, either peaking or combined-cycle technology is added to minimize cost. PP&L St. 7, p. 25.

As noted in the above testimony, EGEAS determines the optimum mix of generation for each hourly load and, thereby, identifies the marginal cost unit. The cost of operating this unit determines the hourly market energy price.

It is noted that the EGEAS model has been used to dispatch units on the PJM system. It is not, therefore, a theoretical model but one which has been tested in the real world environment. Tr. 1685-86 (8/26/97). Furthermore, the EGEAS model is a publicly available model which can be acquired, used and tested by any party. PP&L St. 20-R, pp. 19-21.

The model employed by PPLICA witness Mr. Falkenberg is a theoretical model and is proprietary to his firm. PP&L's witness Mr. Falk identified deficiencies in the model. PP&L St. 20-R. The problem that is common to all of the defects was explained by Mr. Falk as follows:

> The entire raison d'etre for competitive markets is their ability to minimize costs to meet a given level of demand. . . Whenever a production costs simulation produces costs higher then those which are optimal, the result is to overstate what an efficient competitive market could have produced. PP&L St. No. 20-R, p. 7.
>
> ***
>
> Mr. Falkenberg has cut many corners in his model. These cut corners generally produce results, as I shall demonstrate, which do not minimize costs to meet a given load. As a result, they produce higher aggregate prices than a competitive market would. PP&L St. 20-R, p. 8.

Mr. Falk identified five areas in which Mr. Falkenberg's model did not optimize costs. *See* Tr. 1683-84 (8/26/97).

The fact that Mr. Falkenberg's model is not tested in the real world of energy dispatch and is a proprietary model is important. The above-referenced over simplifications and the lack of independent real world application of the model make it unreliable for the purposes for which it was submitted in this proceeding. Indeed, if the Commission were to direct use of different inputs then those which, as explained later, were erroneously employed by Mr. Falkenberg, no party other than PPLICA could run the model. Accordingly, the model is simply not useful in examining the issue of forecasted market prices and the model, and we reject the resulting conclusions from it.

OCA witness D. Smith used the ENPRO model to forecast energy prices. This model is less problematic than the Falkenberg model for two reasons. First, it is an operational dispatch model like EGEAS, not a theoretical model like the Falkenberg model. Second, ENPRO is commercially available, and, therefore can be obtained and run by any participant in this proceeding.

PP&L witness Dr. Jones obtained and ran the ENPRO model to determine whether the results obtained by Mr. Smith were the result of differences in the model or differences between Mr. Smith's inputs to ENPRO and Dr. Jones' inputs to EGEAS. Dr. Jones determined that there were differences in the ENPRO model and Mr. Smith's application of the model which are unrelated to differences in inputs.

The primary deficiency of the ENPRO model is that it can model only 200 units. Tr. 1398 (8/25/97). In order to provide room for the addition of new units, Mr. Smith could model less than 200 of the 350 existing units in PJM. Tr. 1398, 1511 (8/25/97).[21] To accomplish this, Mr. Smith had to aggregate existing units or treat them as one unit. Tr. 1511 (8/25/97). The problem with aggregating units, in this fashion, is that it raises energy prices by using the average cost of the aggregate group rather than the lowest cost at all times.

Mr. Smith's application of ENPRO., as explained by Dr. Jones, assumes that units which can be fired with either oil or gas will use oil one half of the time and gas the other half of the time, regardless of competing fuel prices. Of course, such assumption is unrealistic and biases electricity prices upward since duel fuel units can be presumed to use the lower price fuel. Tr. 1397-98 (8/25/97). As shown in Table D to PP&L's Main Brief, the effect of this is to overstate market value by $159.298 million.

Mr. Smith also reduces the availability of imports from outside PJM after 2005, without explanation or justification. Tr. 1398 (8/25/97). Because imports from the west generally are at lower costs, Tr. 1510 (8/25/97), this increases the price of electricity in PJM just as the 7-year rate cap under the Act expires. The effect of this is to overstate market value be $226.296 million.

Dr. Jones presented Exh. STJ 33 to graphically illustrate the effects of the ENPRO model. Accordingly, the errors in the ENPRO model, and Mr. Smith's application of the model, are significant. Nevertheless, these errors are mostly correctable and, if those corrections are made, the model can provide the basis for a reasonable forecast of energy prices.[22] As shown on PP&L Exh. STJ 33, the remaining differences between the energy prices forecasted by Mr. Smith and those forecasted by Dr. Jones are the result of differences in inputs to the models. When Dr. Jones' inputs were put into the ENPRO model and ENPRO errors were corrected, ENPRO yields essentially the same prices as EGEAS. For this reason it is critically important that the ALJ address the appropriate inputs to the ENPRO and EGEAS models.

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[21] Mr. Smith did not indicate in his direct testimony that ENPRO requires aggregation of units. This is the type of information, however, that can be discovered by other parties when a model is commercially available. There is also no indication in that the Commission was aware of this deficiency in the ENPRO model in the PECO Restructuring proceeding.

[22] The inability of the ENPRO model to reflect more than 200 units, however, cannot be corrected.

The EGEAS model, in contrast, does not contain the methodological problems that have been explained above with regard to the Falkenberg model and ENPRO.[23] Specifically, EGEAS is a dispatch model which has been used for many years in dispatching units on the PJM system. As noted by Mr. Falk:

> I've sold dispatch models commercially, and differences in dispatch and the price and the commitment of units that would be glossed over in two seconds in a regulatory proceeding lead to weeks of meetings [and] rewrites[,] your model against my model in the real world . . . I just don't think, with all due respect to the regulatory process, that it matches the crucible of competition . . . Tr. 1685-86 (8/26/97).

The EGEAS model can model all of the units in PJM as well as necessary additions, it schedules maintenance rather than spreading it arbitrarily throughout the non-summer months, it optimizes new capacity additions to produce the lowest energy costs by choosing between combustion turbine and combined cycle units, it uses appropriate prices for unserved energy and it properly reflects different summer and winter capacity ratings. PP&L St. 20-R, p. 18.

b) Treatment at Start-Up and No Load Costs

The only criticism which other parties have directed at the use of the EGEAS model concerns the treatment of start up or no load costs. This is really not a criticism of the robustness of the model but, instead, its application to determine market clearing prices in this proceeding. Nevertheless, this criticism has been demonstrated by Dr. Jones as having a minimal effect on his forecasted energy prices and the resulting stranded costs of generation.

OCA witness Mr. Smith and PPLICA witness Mr. Falkenberg state that generators would not bid their incremental cost of generation because there are extra costs attributable to start-up that would not be recovered if they happen to be the unit that supplied the last kWh of energy at that point in time. In this way, intervenors argue that PP&L has understated the market clearing price of energy. OCA St. 2, p. 5. Their reasoning is that the incremental cost of some blocks of a

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[23] It also is noted that no witness employed the EGEAS model in the PECO Restructuring proceeding. Since the results of such model were not available for the Commission's consideration in the PECO Restructuring proceeding, the Commission relied upon Mr. Smith's use of ENPRO. Here, the EGEAS model, which is more robust, is the best available model.

unit is below the actual cost of operation at certain loads. Intervenors argue that the only way to account for this reluctance would be to assume that generators adjust upward their initial bids to the average cost of generation (supposing that the average costs of generation always exceeds the incremental cost of generation), because no generator would knowingly bid his incremental cost into the market for fear of losing money on an on-going basis. In the view of at least one of the intervenors, PPLICA St. 2, p. 18, the average full load heat rate would be bid by the generator assuming that the *single heat rate* for each unit was equal to the average full load heat rate.

There are two major flaws in intervenors contention about this "heat rate" issue. First, as Dr. Jones points out, PP&L St. 7-R, pp. 62-63, intervenors do not have a clear grasp of the incentives facing generators in a competitive market. Intervenors idea that no rational generator would knowingly bid his incremental cost for fear of having to forego some start-up costs incorrectly assumes that any individual generator subject to competition would somehow know, in advance and for any hour of the year, exactly when the market for energy would clear at the incremental cost of their unit. Only in this way would the potential cost of not offering capacity to the market offset the financial loss of foregoing the opportunity to earn a profit on that capacity because as long as the supply curve for energy has the usual upward slope, all generators but the last unit dispatched at any point in time will receive a price for that hour that is in excess of their incremental cost.

Second, Dr. Jones correctly notes that whether or not intervenors' allegations are valid (a) is an empirical question requiring proof and, (b) has to recognize that EGEAS does not dispatch an entire unit on the basis of a single heat rate. Rather, in a manner like the way PJM actually dispatches the system, EGEAS divides a generator's capacity into several blocks, each with a different heat rate. At some points in time, the incremental cost of energy based on heat rates is greater than <u>and</u> less than the average cost of generation as shown in PP&L Exh. STJ 22. Dr. Jones summarized his analysis of the issue raised by other parties and his empirical test of the significance of the issue as follows.

> . . . I have tested Mr. Falkenberg's hypothesis for him. Additional runs of EGEAS using Mr. Falkenberg's suggested average heat rate approach result in higher and lower market clearing prices during the year. On balance, PP&L's estimated stranded costs fell by 0.8% or $37 million. I conclude that Mr. Falkenberg's contention

> that PP&L systematically understated market-clearing prices by disregarding the effect of no-load costs and average heat-rates is without merit, apparently designed to alarm the Commission rather than raise a substantive concern. PP&L St. 7-R, pp. 14-15.

As noted in the above testimony, even if generators could know in advance that their bids to supply energy would represent the market clearing price and, therefore, adjusted such bids to cover so called "no load" costs, the effect on PP&L's generation revenues would be sufficient to reduce PP&L's stranded costs by only $37 million out of $4.5 billion[24] or about eight tenths of a percent. It is not at all clear that generators will act, as Mr. Falkenberg surmises in a competitive market where they are seeking to under bid others to sell energy, and are uncertain whether their bids will set the market clearing price. However, even if all generators were to include such costs, which is unlikely, the effect will be to reduce PP&L's $4.5 billion of stranded costs by no more than $37 million and leave such costs still well above the $4 billion recoverable under the rate cap.

For all the foregoing reasons, PP&L has demonstrated that the EGEAS model is the most realistic and robust model for determining energy prices and should be used to determine such prices, if any model is used, in this proceeding.

2. Inputs to Models

As explained in the PP&L M.B., the selection of an appropriate model is an important first step in forecasting energy prices. However, either the EGEAS model or the ENPRO model, with certain corrections, can be used to forecast energy prices. The correct inputs to the model are, by far, the most critical issues in forecasting energy prices and differences in the inputs selected by each witness account for the majority of the differences between the forecasts of the witnesses. This is illustrated by Dr. Jones' rejoinder Exh. STJ 33, which compares the results of OCA's inputs to the ENPRO model with PP&L's inputs to the EGEAS model.

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[24] The issue of failure to cover so called "no load" costs was one of the bases used by the Commission to reject the testimony of PECO witness Heironymus. PECO Order, pp. 85-86. However, Mr. Heironymus did not recalculate the effect on market clearing prices if generators increased their bids to include such costs, as Dr. Jones did, but instead simply assumed there would be uplift payments to generators which would not affect the market clearing price. PECO Order, pp. 85-86.

It is, therefore, very important that the Commission carefully review the inputs that have been selected by the witnesses. OCA's and PPLICA's witnesses have used forecasts of fuel prices and inflation -- the two most critical inputs -- which are prepared by entities that have consistently overstated such variables in the past. For the reasons explained below, PP&L's inputs to the EGEAS model are reasonable.

a) Fuel Prices

(1) Projected Oil and Gas Prices

Perhaps the most critical and significant input to the models is the cost of fuel to operate each unit that generates electricity. Since the energy price for all units running in a given hour equals the cost of operating the marginal cost unit operating in that hour, the variable cost of operating the marginal cost unit is critical. Fuel price is the primary component of variable cost.

As explained by Dr. Jones, a forecast of fuel prices must reflect the fundamentals of fuel markets. In particular, two concepts are extremely important. The first concept is that increases in fuel prices should be separated into two components: increases in real fuel prices (exclusive of inflation) and increases in fuel prices due to inflation. The combination of the increase in the real fuel price and the effect of inflation on the fuel price produces the nominal fuel price at any point in time.

The second concept is that projected increases in one fuel price, such as natural gas, must be reviewed in the context of competing fuels such as oil and coal. Both common sense and experience demonstrate that prices of competing fuels move in tandem and forecasts which project different rates of increase for competing fuels are highly suspect. Application of these fundamental concepts to the fuel price forecasts of each of the witnesses demonstrates that Dr. Jones' forecast is, by far, the most reliable and most reasonable forecast.

Dr. Jones forecasted that 1996 real fuel prices would remain flat until 1999. Dr. Jones then forecasted that real fuel prices would remain flat and that nominal fuel prices would increase with inflation from 1999 forward. PP&L St. 7-R, p. 41.[25]

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[25] Fuel prices peaked in 1996 and began to decline in 1997. PP&L St. 7-R, p. 43. Therefore, the subsequent experience tends to confirm that Dr. Jones' use of the 1996 nominal prices as the starting point for 1999 is appropriate.

Dr. Jones projected that real fuel prices would remain flat after 1999 because history demonstrates that real fuel prices rise and fall but revert to a mean price of about \$15.50 in 1996 dollars over the long term. PP&L St. 7-R, p. 47. As shown in Dr. Jones' Exh. No. STJ 16, oil prices averaged about \$15.50 a barrel (in 1996 dollars) over the period 1900 to 1996 excluding the unusual period of 1979 to 1985 represented by the Iranian Revolution. It is noted, however, that other disturbances like the Gulf War are included in the experience period. Nevertheless, Dr. Jones adopted a real oil price of \$18.00 per barrel, Exh. No. STJ 16, which corresponds to the average price of \$17.90/Bbl over the last 10 years. PP&L St. 7-R, p. 54.

Only Mr. Knecht, on behalf of OSBA,[26] attempted to refute Dr. Jones' explanation that real prices are mean reverting, by calculating a .8% rate of increase in the price of oil from 1939 to 1996. OSBA St. 51, pp. 17-22; OSBA Exh. RDK-S-2. However, Dr. Jones explained in rejoinder that the choice of a particular starting year substantially effects this type of calculation. If Mr. Knecht had chosen any of 24 differing starting points since 1900 there would have been real declines in oil prices and, if many other starting years were used, real oil prices would simply be flat. Tr. 1404-05 (8/25/97). As a result, simply choosing a starting point year near the end of a depression when oil prices were low proves nothing about the long term trend of real oil prices.

Finally, Dr. Jones explained that projections of rising real fuel prices are contrary to both the weight of historic evidence and the progress of technological developments in exploration for fuels. PP&L M.B. 66.

> Q. Are Mr. Knecht's conclusions then in error in concluding that real fuel prices will increase?
>
> A. Real fuel prices, there's absolutely no evidence that real fuel prices will increase over the long term. In fact, it's the very progress that energy companies have made with regard to technology innovation when it comes to locating and producing energy that suggests that technical progress will continue to overcome the apparent assumption that seems to drive forecasts like those used by Mr. Smith and Mr. Falkenberg.

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26 Mr. Knecht did not forecast energy prices in this proceeding.

> Their forecasts rely on the assumption that technology is losing ground to the idea that energy is a finite resource and there is only so much oil and gas and uranium in the ground, so prices must rise.
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> Professor Morris Adelman, MIT's best known natural resource economist, addressed that issue head on in his book, "The Economics of Petroleum Supply."
>
> Professor Adelman states in Chapter 13 under a heading called, "Prices Should Rise and Do Not," he says, "The assumption of an initial fixed mineral stock is not only wrong but superfluous. All else being equal, the replacement cost of any mineral should constantly increase over time and the price with it, yet prices of minerals have not risen.
>
> Practically all have been flat or actually declining in the long run. The argument now among econometricians is whether we must reject or accept a long-term downward trend for minerals prices. Long-term increases is not even in question. All else has not been equal.
>
> Mineral depletion is in fact an endless tug of war, diminishing returns versus increasing knowledge, and so far the human race has won big. Tr. 1405-06 (8/25/97).

The evidence, therefore, supports only a conclusion of flat real fuel prices.

Messrs. Falkenberg (PPLICA) and Smith (OCA) rely on the forecasts prepared by DRI and EIA respectively. By increasing nominal fuel prices more than their projected increases in inflation, these forecasts effectively project both increases in real fuel prices and increases in fuel prices due to inflation. PP&L St. 7-R, p. 55; Tr. 1404 (8/25/97). Yet neither witness has presented any substantive basis for concluding that real fuel prices will rise. In this regard, it is to be noted that Dr. Jones real oil price of $18.00/Bbl is essentially equal to the $17.90/Bbl average price over the last 10 years and is significantly above the $15.50/Bbl average long-term price of oil in 1996 dollars excluding years affected by the Iranian Revolution. PP&L St. No. 7-R, p. 54. Accordingly, Dr. Jones' projection of real oil prices is on the high side of average historical prices. Furthermore, as shown on PP&L Exh. STJ 18, one standard deviation around this average price establishes a range of $12/Bbl to $19/Bbl. While oil prices may rise and fall above the average it is reasonable to conclude that they only rarely will move outside one standard deviation. As also shown on Exh. STJ 18, in contrast to Dr. Jones' real oil price of $18/Bbl, Mr. Falkenberg's (EIA's) real oil prices begins at about $19/Bbl and continually rises throughout the forecast period to prices of about $24/Bbl, well outside one standard deviation from the average price. The DRI forecast used by OCA produces similar results. PP&L Exh. STJ 19. Accordingly, the expectation of these forecasts -- that real oil prices will rise -- is simply not supportable given historic trends. Equally important, neither OCA's nor PPLICA's witnesses has presented any evidence to support such real price rises, they have simply accepted the DRI and EIA forecasts.

The witnesses' use of the DRI and EIA fuel prices is difficult to explain given that both entities have continually over-estimated fuel prices. As shown on PP&L Exhs. STJ 14a and 14b, each of EIA's 1986, 1987, 1989 and 1992 long term fuel price forecasts has consistently overstated fuel prices. DRI's fuel price forecasts closely matches EIA's over-estimates. PP&L Exh. STJ 19. As shown on PP&L Exh. STJ 35, DRI's 1994 and 1995 forecasts also overstated inflation and, thereby fuel prices. Dr. Jones explained that the EIA and DRI fuel price forecasts are based upon macro economic models which forecast ever increasing growth without recession. This creates an upward bias to both real fuel prices and inflation. Further, these forecasts assume increased energy demand without technological innovation. PP&L St. 7-R, pp. 57-58. Regardless of the reason, the record demonstrates that these forecasts have consistently overstated fuel prices and are proven to be unreliable to forecast fuel prices and, ultimately, energy prices in this proceeding.

As noted above, the projection of fuel prices is affected by both the projection of real fuel price change, if any, and changes in fuel prices due to inflation.

As explained more completely in the inflation section of this brief, Dr. Jones projected a constant inflation rate of 2.5% and applied that inflation rate to fuel prices commencing in 1999. OCA witness Mr. Smith did not separately project real fuel prices and the effect of inflation on such prices. Instead, Mr. Smith simply adopted the DRI 1996 forecast of fuel prices.

As shown in PP&L Exh. STJ 21, the DRI 96 forecast begins with average inflation rates of 2.3% for 1997-2000, but then increases inflation rates to a level of 3.5%, on average, for the period 2005-2015. OCA's Mr. Smith revised his forecast to reflect the updated DRI Spring 1997

Outlook, Tr. 1516-17 (8/25/97), and to correct a "starting point" problem Dr. Jones noted in his testimony. PP&L Exh. STJ 12. Even so, the updated Spring 1997 Outlook continues to use the much higher 3.5% average annual inflation rate for the period 2005-2010.

Mr. Falkenberg used the EIA forecast for 1997. As also shown in Exhibit STJ 21, the EIA forecast starts with inflation at 2.5% and raises it to 3.4 % on average for 2005-2010 and 3.6% on average for the period 2010-2015. As shown on PP&L Exh. STJ 35, DRI has consistently over-estimated inflation in past forecasts. EIA forecasts match DRI's forecasts closely. PP&L Exh. STJ 19.[27]

Neither Mr. Smith nor Mr. Falkenberg has offered any explanation why the inflation rates built into the DRI and EIA fuel forecasts escalate over time. Tr. 1403 (8/25/97). These inflation forecasts are from the DRI and EIA fuel price forecasts. Despite reliance on these forecasts neither witness even obtained the full source documents for these forecasts or analyzed the bases used in these forecasts to estimate inflation. Tr. 1517-18, 1750 (8/25/97). Accordingly, they have not examined the bases for these forecasts and have blindly accepted them as reasonable. As explained by Dr. Jones, forecasts of inflation which rise over time are simply inconsistent with federal reserve policies observed over the last decade. Tr. 1400 (8/25/97). These witnesses have provided no bases to justify the use of the EIA and DRI inflation estimates and the record demonstrates that their forecasts have consistently overstated inflation.

The rising rates of inflation combined with rising real oil prices projected by these parties create what Dr. Jones referred to as the "dog leg" problem. The DRI and EIA forecasts initially project gradual rises in fuel prices but as the higher inflation rates and increases in real fuel prices "kick in," nominal fuel prices rise sharply. As shown graphically in PP&L Exhs. STJ 14a and 14b, the fuel price curve slopes upward in the shape of a dog leg. As explained by Dr. Jones there is no precedent in history for such an effect, PP&L St. No. 7-R, p. 42, and, in past forecasts, this phenomenon accounts, in part, for DRI's and EIA's confirmed over-forecast of fuel prices. PP&L Exhs. STJ 14a and 14b.

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27 Although EIA reduced its short term fuel forecast downward, Mr. Falkenberg made no adjustment to reflect lower fuel prices. Tr. 1751-52 (8/25/97).

In PECO's Restructuring proceeding, OCA witness Smith as well as the three PECO witnesses relied in their final testimony on the Spring 1997 DRI forecast (Revised DRI)[28] and witness Falkenberg relied, as he did here, on the EIA forecast. As a result, the reasonableness of the Revised DRI forecast and the EIA forecast were not at issue in the PECO Restructuring proceeding. As explained above, the weight of the evidence in this proceeding is that these forecasts are unreliable. Accordingly, the record in this proceeding compels rejection of such forecasts.

(2) Relationship of Fossil Fuel Prices - The Divergence Issue

There is yet another significant problem with use of DRI and EIA fuel price forecasts in this proceeding. In addition to the errors of improperly rising real fuel prices and increasing inflation rates, these forecasts project a divergence between the real prices of oil and gas versus the real price of coal. This is illustrated graphically on Dr. Jones' PP&L Exh. STJ 10, which shows the difference in rates of escalation in gas and oil prices relative to escalation in coal prices in the DRI forecast.

The divergence of gas and oil prices from coal and uranium prices is both illogical and unprecedented for competing fuels. As demonstrated by Dr. Jones in PP&L Exh. STJ 16a, real prices of competing fuels are highly correlated over the 15 year period of 1981-1995. In other words, the prices of these fuels move up and down together. This history also makes sense. If the price of one competing fuel rose sharply and others did not move upward, there would be fuel switching in many applications. PP&L St. 7-R, pp. 47-49. This is particularly the case for gas and oil versus coal. As also shown in PP&L Exh. STJ-16a, Dr. Jones's forecasts of the prices of each type of fuel are highly correlated. On the other hand, the fuel price projections of DRI and EIA show a significant, and historically unprecedented, divergence of oil and gas prices from the price of coal.

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[28] PECO witnesses Heironymus and Bustard used the 1996 DRI forecast initially and updated to the Spring 1997 DRI forecast. PECO witness Venkateshivara initially used his firm's ICF forecast but was replaced by witness Rose who used the Spring 1997 DRI forecast. *PECO* Order, p. 87. The Commission found troublesome these forecast changes. *PECO* Order, p. 87. Dr. Jones did not change his fuel price forecast in this proceeding. OCA witness Mr. Smith changed from the Fall 1996 DRI forecast to the Spring 1997 DRI forecast. OCA St. 2-S, p. 2.

The "divergence" problem is particularly critical to the issues of stranded costs in this proceeding. The marginal cost units operating on PJM will normally be gas and oil fuel units, and these units will set the price for all units operating in the same hour. OCA and PPLICA understate the costs of operating PP&L's coal generating units by assuming coal prices that are inconsistent with oil and gas prices used in their models. The result is an understatement of stranded costs associated with these units.

The divergence of coal prices and oil and gas prices was not an issue in the PECO Restructuring proceeding for several reasons. First, as noted previously, all parties in that proceeding employed either the Spring 1997 DRI forecast or the EIA forecast. Accordingly, no party in the PECO proceeding challenged the divergence of oil and gas prices versus coal prices. Second, PECO's coal fired generating plants account for a relatively small portion of PECO's generation. *See* PECO Exh. 2, Sched. G-7, App. A-25, at R-00973953. In stark contrast, PP&L's coal fired generating plants account for 38% of its generation. *See* PP&L Hrg. Exh. 2, Filing Requirement RP-G.6, Attach. 2. Accordingly, the historically unprecedented divergence of coal prices from oil and gas prices predicted by DRI and EIA has a disparate effect on the calculation of PP&L's stranded costs as compared to PECO.

As illustrated by PP&L's table, at page 72 of its M.B., the coal prices paid to operate PP&L's coal-fired generating plants, would be significantly higher if coal prices are escalated at the same rates assumed by DRI for gas prices. Therefore, even if the DRI gas and oil prices were accepted, despite all of the evidence in this proceeding that they are overstated, the Commission must, *at a minimum*, adjust upward the coal prices assumed by DRI. To do otherwise is not only contrary to the record but would punish PP&L for owning and operating coal plants that have produced low cost electricity for many years.

In order to further illustrate the effect of correcting the divergence of oil and gas prices from coal prices on PP&L in light of the PECO Order, PP&L has submitted a recalculation of its stranded costs which, among other things, uses prices for coal that escalate in a manner that is consistent with DRI's escalation of oil and gas prices. Correction of this divergence problem alone would create an increase in stranded costs of $230.157 million. See Table D to PP&L M.B..

For all the reasons noted above, the DRI and EIA fuel price forecasts are overstated. These overstated fuel prices result in a significant overstatement of energy prices forecasted in Mr. Smith's (OCA) ENPRO model and Mr. Falkenberg's (PPLICA) model. We reject these fuel price forecasts as unreliable inputs to any model and direct use of fuel price forecasts developed by Dr. Jones. The effect of the different fuel price forecasts pervades the market price analysis and is difficult to isolate. The parties differ in both their forecast of real price changes and inflation. The total effect of the different inflation assumptions is $198.563 million as shown on Table D. This includes both effects of inflation on fuel and non-fuel costs and the effect on inflation on market prices.

b) Inflation

The forecast of inflation is significant both as it affects fuel prices, as explained in the previous section of this Brief, but also because inflation is used to escalate other costs that are used in each of the models to derive market prices of electricity. In particular, variable O&M costs must be projected for each of the units that will be operated. Each of the witnesses applies an expected inflation rate to current levels of variable O&M costs to derive future O&M costs.

There are two issues with regard to the projection of inflation. The first is what measure of inflation should be used. The second is the year by year amount of inflation.

With regard to the proper measure of inflation, Dr. Jones explained that the Consumer Price Index (CPI) is clearly overstated as to costs faced by PP&L because it relates to consumer products and not to items that affect PP&L's generating costs. While the Gross Domestic Product (GDP) deflator is a better indicator of the effect of inflation on such costs, this measure includes long-lived assets as if they were purchased monthly. Dr. Jones, therefore, concluded that the Producer Price Index (PPI), which measures prices received by industrial firms for goods they produce is the best indicator of costs to be incurred by PP&L. PP&L St. 7-R, pp. 60-61. Noting that long-term forecasts of the PPI, even by DRI, averaged less than 2.5% per year, Dr. Jones estimated average future inflation at 2.5%. PP&L St. 7, p. 40; PP&L St. 7-R, p. 61.

> OCA's and PPLICA's witnesses did not evaluate the proper measure of inflation or attempt to estimate inflation. As explained previously in conjunction with fuel price projections, OCA and PPLICA simply adopted the rising inflation rates contained in the DRI and EIA forecasts. Tr. 1401-02 (8/25/97). OCA and

PPLICA cannot explain the basis for these increasing inflation estimates because they blindly accepted the numbers in the fuel price forecasts. Dr. Jones explained the unreasonableness of the continually rising inflation scenario as follows:

> [F]or inflation to be sustained at an increasing rate over time, which is the assumption embedded in the intervenors' forecasts, it has to be the federal government with the cooperation of the Federal Reserve Board that has embarked on an expansionary policy supported by increases in the money supply.
>
> This is absolutely opposite from the policies and the Fed activity that has been going on since the Reagan years. My estimate for inflation reflects a continuation of that current policy. Hence, I set inflation at its long-term trend of 2.5 percent and held it there. I have no evidence that anything to the contrary will prevail.
>
> Q. Have other forecasters made similar projections?
>
> A. The Federal Reserve Bank of Philadelphia released its survey of professional forecasters just earlier this month, showing that the expected change in the GNP deflator, which is a measure of overall inflation in the economy that was adopted by Mr. Falkenberg and Mr. Smith for this proceeding, would grow at 2.3 to 2.5 percent over the next two years.
>
> This same group of forecasters expects the Consumer Price Index, which as I'm sure you're familiar with is a measure of inflation based on consumer goods, they expect the CPI to grow 2.7 percent over the next ten years.
>
> Now, I'd like to point out that historically the difference between the CPI and the GNP deflator has been about minus 4/10th percent, suggesting that the forecasters would set a ten year outlook for the GNP deflator below my 2.5 percent inflation rate.
>
> On top of that, I would add that what is important is what people think or expect inflation to do over the long term.
>
> As you can see from Exhibit STJ-34 which I passed out earlier this morning, and that I actually have had blown up for purposes of this proceeding today, that the inflation fears of Americans have been fading rapidly since the start of this decade and are now well below 3 percent.

> And Alan Blinder, who [was] vice chairman of the Fed during the period when a lot of this activity to reduce inflation was going on, has been quoted as saying, "When I was on the Fed, we said our goal was to cap inflation at 3 percent and then bring it down. Now, that view is being taken as much too pessimistic." Tr. 1400-01 (8/25/97).
>
> PP&L M.B. pp.75-77.

For all of the foregoing reasons, including those explained in the fuel price section of this decision, OCA's and PPLICA's "adoption" of DRI's and EIA's unexplained rising inflation scenario is rejected. A steady 2.5% inflation rate is consistent with current experience and modern monetary policy.

c) Load Growth and Electricity Demand

PP&L forecasted electricity demand for PJM by adopting the most recent forecast of demand compiled by PJM. Updates for demand on PP&L's system through December 1996 were reflected. PP&L St. 7, p. 44. PP&L estimated demand growth of about 1.5% annually. No party has raised any issue with regard to forecasted demand.

d) Efficiency of New Capacity

Efficiency of new capacity is principally an issue with regard to the development of capacity prices and whether capacity prices, in combination with energy prices, are sufficient to provide a return that will support the addition of new units when they are needed. As explained previously with regard to capacity prices, Dr. Jones' projected market prices for capacity and energy are sufficient to support installation of new units.

The efficiency of new units also effects energy prices. In the EGEAS model, Dr. Jones made a very conservative estimate of the fuel consumption of new combined cycle and combustion turbine units. He assumed that a combined cycle unit would require 7000 BTUs of energy to produce a kWh and that a combustion turbine would require 10,200 BTUs to produce a kWh. PP&L Exh. STJ 5. These assumptions are conservative. For example, many existing combined cycle units already can produce one kWh at lower BTU levels (i.e. lower heat rates). PP&L Exh. STJ 28R. Reflection of these lower actual heat rates in EGEAS would have resulted in lower energy prices and higher stranded costs because it would take less fuel to produce each kWh of energy from new units. For this reason, no party has challenged the reasonableness of the efficiency assumptions used in EGEAS to project energy prices. Tr. 1392 (8/25/97).

e) Other Inputs

There are several other inputs to the energy price models which, while less critical than the inputs explained above, have a relatively significant effect on the resulting energy prices produced by the models. These inputs are explained briefly.

(1) Nuclear Capacity Factor

Nuclear capacity factor refers to the percentage of the time that base load nuclear units will be operating. The use of a nuclear capacity factor that is too low in the models raises marginal energy prices by requiring other units with higher variable costs to operate. If actual nuclear capacity factors turn out to be higher than reflected in the models, actual energy costs will be lower than projected by the models.

Dr. Jones employed a forecasted 78% nuclear capacity factor in the EGEAS model based upon a study of actual unit availability factors in PJM and other systems. PP&L St. 7, p. 30. The data used to calculate availability is provided in PP&L Exh. STJ 6. Mr. Smith, without any support or explanation, "assumed . . . a 75% annual capacity factor . . ." OCA St. 2, p. 21.[29]

Dr. Jones explained in rebuttal testimony that the availability of nuclear units has been steadily increasing and is projected to increase further:

> Nuclear unit availability of 78 percent is conservative. Nuclear unit availability has improved considerably in the United States in the last 10-15 years and is expected to continue to improve. Exhibit STJ-30 shows historical availability factors for nuclear units in the United States from 1982 to 1995. In that period, availability factor has improved steadily from about 65 percent to nearly 80 percent. Mounting experience in operating nuclear units has led to better management practices and fewer forced outages. For example, units experienced nearly 900 hours of forced outage in 1991. This number dropped to below 700 hours in 1995.

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[29] In the PECO Restructuring proceeding, both PECO and OCA used a 75% nuclear capacity factor. As a result, use of a higher factor was not an issue in that proceeding. However, the Commission observed that PECO's actual nuclear capacity factor was <u>below</u> this level and, as a result, use of 75% was favorable to PECO. PECO Order, p. 89. In contrast, use of the industry average here would penalize PP&L and deprive <u>PP&L</u> of the benefit of its higher nuclear capacity factor.

> Moreover, NERC forecasts show that this trend is expected to continue. Exhibit STJ-30 plots forecasted capacity factors to 2006 (actual capacity data are shown from 1991 to 1996). Because nuclear units are typically run at full load whenever they are available, anticipated capacity factors should closely mirror, though by slightly lower than, anticipated availability. NERC forecasts suggest availability factors of at least 85 percent should be expected for the next decade. Thus, 78 percent is a somewhat conservative estimate of future nuclear availability. PP&L St. 7-R, pp. 106-107.

Mr. Smith did not respond, in surrebuttal testimony, to Dr. Jones above quoted explanation. Mr. Smith has not provided any basis to employ a 75% nuclear capacity factor for PP&L. Accordingly, the record supports only the 78% nuclear capacity factor recommended and employed by Dr. Jones.

(2) Variable O&M Costs

Another element in projecting generating costs is the variable Operation and Maintenance expenses (O&M) of each unit. Variable O&M expenses are those associated with the production of energy as contrasted with fixed O&M which are costs associated with maintaining plants ready to operate.

Dr. Jones forecasted variable O&M expenses by escalating current variable O&M costs for each plant. Dr. Jones explained that the experience in industries that have moved from regulation to competition is that O&M expenses increase, for a period of time, at rates that are less than the rate of inflation. For this reason, Dr. Jones selected escalation rates for variable O&M expenses of 2% for 1997-2000, 1.5% for 2001-2005 and 2.5% for 2006-2016. PP&L Exh. STJ 4.

Dr. Jones explained his projection as follows:

> My view of future changes in variable O&M costs, as shown in Exhibit STJ 4, stems from three sources of data. First, an examination of the trends in O&M costs in capital intensive industries beginning with the 1980's suggests that periods of competitive change often cause internal cost escalation rates in variable O&M to decline, at least in real terms. For example, a recent article on the highly-competitive (and partially regulated) oil

> refining industry, cited data showing O&M costs declining as much as 10-15 percent per year over the last several years[30].
>
> Second, the recent restructuring that has taken place in the natural gas pipeline industry caused variable O&M costs to trail inflation. Following FERC Order No. 636, pipeline company restructuring produced firms that were encouraged to respond to competitive pressures, and firms that encouraged the introduction of cost-saving technology. Third, evidence and opinion from various industry and academic publications suggest that variable O&M costs in parts of the industry may by rising slower than inflation for some time. PP&L St. 7, p. 41-42.

PP&L M.B. pp. 79-80.

OCA's and PPLICA's witnesses simply applied the inflation forecasts contained in the DRI and EIA fuel price forecasts to current levels of variable O&M costs.. As explained by Dr. Jones, and as further illustrated in his rebuttal testimony, PP&L St. 7-R, pp. 22-25 and PP&L Exh. STJ 9, competition in the rail, trucking, airline and natural gas industries has produced ". . . double digit decreases in prices and costs of production . . ." PP&L St. 7-R, p. 24.

For these reasons, Dr. Jones' projections of variable O&M costs are both reasonable and conservative in that they likely overstate costs given the proven effects of introducing competition in other industries.

(3) Reserve Requirements

Reserve requirements refer to the amount of capacity which is required above expected demand to serve unexpected contingencies such as an unplanned outage of a generating station. PJM currently plans for a 20% reserve requirement. PP&L St. 7, p. 23. However, Dr. Jones concluded that competitive pressures will lower reserve requirements to 18%. PP&L St. 7, p. 24. Mr. Smith also assumed a going forward reserve requirement of 18% although he indicated that this might not be achieved by 2000. OCA St. 2, p. 18. PPLICA's witness did not address reserve requirements.

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30 Anne Rhodes, "Hostile Operating Climate Augurs Further Closures for U.S. Refiners," *Journal*, March 10, 1997, 21-23.

It is noted that reserve requirements affect energy prices by determining the timing of additions of new capacity. As new capacity is added marginal energy prices will generally decline because the new capacity is more efficient (less fuel or BTUs to produce each kWh). Thus, perhaps counterintuitively, higher reserve requirements mean lower energy prices. Therefore, Dr. Jones adoption of an 18% reserve requirement, as compared to the current 20%, increases energy prices and lowers stranded costs. If Dr. Jones had continued to employ a 20% requirement, it would have forced the model to add new efficient additions at an earlier date and energy prices would have been lowered. Accordingly, the 18% reserve requirement is conservative and again properly and consistently reflects the future effects of competition.

(4) Environmental Costs

In projecting energy prices it also is necessary to include certain environmental costs which will affect the cost of operating the marginal cost generating unit. As explained by Dr. Jones, the EGEAS model permits input costs of emission allowances as an adjustment to fuel price escalators. Dr. Jones explained how EGEAS models SO_2 emission allowance as follows:

> The first step is to identify which units will be running when the region is not in compliance. EGEAS accomplishes this by checking the emission production rate against the annual emission limit input for each facility. Once the units are identified, then those units that are subject to emissions limits are assigned allowances sufficient to bring them into compliance. The cost of bringing those units into compliance is built into the fuel escalation rates for PJM. PP&L St. 7, p. 42.

To determine the emission allowances Dr. Jones reviewed the history of SO_2 allowance prices, which have steadily declined, and he reviewed forecasts of allowance prices. Dr. Jones adopted the ICF Kaiser low case estimates of allowance prices through 2000 and escalated those allowances by the 2.5% expected inflation rate which he applied to escalate other costs. PP&L St. 7, pp. 41-42.

Dr. Jones did not include NO_x allowances as a cost in developing energy prices because of the great uncertainties in the development of technology to reduce NO_x emissions, uncertainties as to the levels of controls required for NO_x, the fact that NO_x controls are applied only in the ozone period of May through September and the lack of a developed market for NO_x allowances. PP&L St. 7, pp. 43-44; PP&L St. 7-R, pp. 97-104.

OCA witness D. Smith contended that NO_x emission allowances will increase energy prices by something less than $1/Mwh. He also argued that NO_x allowances would have a significant effect on PP&L's net revenues, but he did not quantify such effect. OCA St. 2, p. 24.

In rebuttal, Dr. Jones explained the history of declining SO_2 allowance prices and that the competitive market would similarly drive down NO_x compliance costs. Dr. Jones concluded that electricity prices would rise from about $.05/Mwh to $.30/Mwh as a result of NO_x emissions with the higher end of the range being experienced late in the transition period when NO_x standards tighten. Therefore, the combination of a minor price effect occurring late in the transition period has a very small effect due to the present value impact. PP&L St. 7-R, p. 102.

No party responded to Dr. Jones' rebuttal on NO_x emission costs. The evidence demonstrates that NO_x emission costs are not a relevant factor.

(5) NUG Output

An additional input to energy price models is the output of NUGs. While there is no dispute that the output of energy from these sources must be included in modeling energy prices, there is a dispute concerning the capacity factor at which these units will operate. Dr. Jones used a 90% capacity factor based upon actual historic experience provided by PP&L witness Mr. Krall within PP&L's service territory. PP&L St. 7-R, p. 105.[31]

OCA witness Mr. La Capra argues that PP&L has overstated NUG output by 10-15%. OCA St. 1, p. 10. However, as explained in Mr. Krall's rebuttal testimony, the NUG capacity factors used by PP&L were those actually experienced for the 3 years 1994-1996 on PP&L's system. As Mr. Krall also explained, most NUGs have now been on line for some time and early operation and start up issues have been resolved. Because there are strong incentives for high output created by payments on the basis of kWh output, these units are, and will remain, well maintained. It is, therefore, reasonable to conclude that future output levels will equal or exceed recent historic levels. PP&L St. 10-R, p. 40.

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31 The capacity factor is relevant because, all other things being equal, higher levels of output by the NUGs will reduce energy prices by displacing the dispatch of a higher cost marginal unit.

OCA has provided no reasonable basis to reject use of these actual capacity factors for NUGs. As shown in Table D, OCA's use of a lower capacity factor for NUGs understates stranded costs by $56.911 million.

(6) Revenues from Ancillary Services

Another element which was considered in forecasting the market price of energy is ancillary services. As explained, the only ancillary service that affects the market price of energy is spinning reserves. How spinning reserves were reflected in the EGEAS model was explained as follows:

> I specified in EGEAS a spinning reserve requirement. As a result, EGEAS ensures that sufficient spinning reserves exist for every hour. In order to meet this requirement, EGEAS adjusts its energy dispatch so that sufficient units capable of providing spinning reserves are on line. PP&L St. 7-R, p. 90.

PP&L M.B. 83-84.

By including the spinning reserve units as units dispatched, EGEAS includes the effects of a spinning reserve requirement in its determination of hourly energy prices.[32]

It is also noted that the revenues received from spinning reserve operators are likely to cover only the variable costs (start up and no load costs). Accordingly, such revenues will not reduce PP&L's stranded costs of generation because they will recover only variable costs and can contribute nothing toward the recovery of fixed costs. PP&L St. 7-R, p. 89.

Although there are potentially other sources of revenues from ancillary services, these revenues will not affect market clearing prices for energy. Furthermore, the amounts of these revenues are not significant. As noted by Dr. Jones, revenues derived from payments for non-spinning reserves should be very small given the large amount of capacity in PJM and the relatively small non-spinning reserve requirement. PP&L St. 7-R, p. 91. Similarly, frequency and voltage regulation will be provided at cost and would produce no contribution to fixed or stranded costs. PP&L St. 7-R, p. 92.

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[32] To further demonstrate that the effects of including a spinning reserve requirement are reflected in the EGEAS market energy prices, Dr. Jones reran EGEAS without a spinning reserve requirement and showed that his projected energy prices would be $.20/Mwh lower without the spinning reserve requirement. PP&L St. 7-R, p. 90.

While other parties raised questions about ancillary services, OCA St. 2, pp. 8 and 30, rebuttal has demonstrated that the effects of ancillary services on market clearing energy prices have been properly reflected in the EGEAS model. OCA provided no response in surrebuttal. Therefore, there is no remaining issue.

(7) Other Inputs and Factors Affecting Energy Prices

One other issue raised by other parties concerns the effects on market clearing energy prices that would be created if there were an earlier than expected retirement of a generating plant.

Dr. Jones used projected retirement dates provided by Mr. Krall in PP&L St. 10-R. These dates reflect the retirement dates reflected in PP&L's last base-rate proceeding and are the dates reflected in PP&L's current depreciation rates. PP&L St. 7-R, p. 87.

OSBA's witness Mr. Knecht, OSBA St. 1, pp. 30-31, and OCA's witness D. Smith, OCA St. 2, p. 19, argued that economic conditions could cause earlier retirements and that early retirements would raise energy prices. Dr. Jones, however, explained the error of such unsupported contentions as follows:

> As noted earlier when demonstrating the results of OCA's requested rerun of EGEAS, new CC units will tend to displace existing fossil units. Adding efficient CC capacity in place of less efficient generation lowers, rather than raises energy prices as intervenors seem to suggest. PP&L St. 7-R, pp. 86-87.

PP&L also notes that Mr. Smith's application of ENPRO assumes that all plants will remain in service throughout the projection period. It neither reflects PP&L's projected retirements nor the proposal of OCA witness La Capra who accepted PP&L's book retirement dates, with the exception of the Keystone and Conemaugh stations. OCA St.1, p. 16.

Dr. Jones' use of PP&L's current projected retirement dates as used in PP&L's last rate case is appropriate and conservative. Retirements dates of other PJM units is similarly supported. PP&L St. 7-R, p. 87. The effect of using PP&L's retirement lives in Mr. Smith's market price analysis and replacing the retired units with combined cycle units decreases market prices as a result of installation of more efficient units and increases stranded costs by $144.181 million as shown in Table D attached to PP&L's M.B.

D. Conclusion

Dr. Jones' forecasted energy and capacity prices provide a consistent and reasonable basis to determine PP&L's stranded costs of generation. The record in this proceeding demonstrates that the EGEAS model is, the most realistic and reliable model for projecting energy prices. While numerous issues have been raised by various parties concerning the appropriate inputs to the model, the record demonstrates that inputs selected by Dr. Jones are consistent and properly reflect expectations in a competitive market.

If the Commission concludes that a change to one or more of these inputs is supported by the weight of evidence, it must see to it that the remaining inputs are consistent[33] and reflect competitive conditions to be faced by PP&L.

V. REVENUE UNDER REGULATION

A. Jurisdictional allocation

As explained in Section III, *supra*, we set forth PP&L's determination of its total stranded costs which was calculated using the applicable revenue requirements over the term or life of its generation-related assets or liabilities, and then compared those amounts to the estimated annual generation-related revenues that PP&L would receive in a competitive environment. The Company's stranded cost claim reflects the applicable PUC-jurisdictional revenue requirements associated with those generation-related assets and liabilities that would be recoverable from customers under traditional rate regulation.

PP&L submitted extensive evidence in this proceeding regarding its proposed PUC-jurisdictional allocation and its generation-related revenue requirement under traditional rate regulation. The parties raised numerous objections to different aspects of the Company's filing.

B. Cost Of Capital

The calculation of the appropriate rate of return, particularly the determination of the common equity element, was a major issue in this proceeding. Although the quantification of rate of return is subject to various methodologies and interpretations of financial data, the

[33] For example, the inflation rates embedded in fuel cost escalations should match the inflation rates assigned to other inputs.

definition of rate of return is not disputed. As explained in P. Garfield and W. Lovejoy, Public Utility Economics 116 (1964),

> [t]he rate of return is the amount of money a utility earns, over and above operating expenses, depreciation expense and taxes, expressed as a percentage of the legally established net valuation of utility property, the rate base. Included in the 'return' are interest on long-term debt, dividends on preferred stock, and earnings on common stock equity. In other words, the return is that money earned from operations which is available for distribution among the capital. In the case of common stockholders, part of their share may be retained as surplus. The rate-of-return concept merely converts the dollars earned on the rate base into a percentage figure, thus making the item more easily comparable with that in other companies or industries.

(Emphasis in original).

A public utility, whose facilities and assets have been dedicated to public service, is entitled to an opportunity to earn a fair rate of return on its investment. The standards to be used by the Commission in determining what is a fair rate of return are well established and were set forth more than seven decades ago by the United States Supreme Court in Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia (Bluefield), 262 U.S. 679, 690-93 (1923):

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility of its property in violation of the Fourteenth Amendment. . . .
>
> . . . .
>
> . . . The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

These principles have been adopted and applied by Pennsylvania's appellate courts in numerous circumstances. See, e.g., Lower Paxton Township v. Pennsylvania Public Utility Commission, 13 Pa. Commonwealth Ct. 135, 317 A.2d 917 (1974); Riverton Consolidated Water Co. v. Pennsylvania Public Utility Commission, 186 Pa. Superior Ct. 1, 140 A.2d 114 (1958).

As the United States Supreme Court stated in three landmark opinions, the return allowed to investors must be commensurate with the risk assumed. The Bluefield decision requires that the rate of return reflect "a return on the value of the [utility's] property which it employs for the convenience of the public equal to that generally being made at the same time on investments in other business undertakings which are attended by corresponding risk and uncertainties" (Id. at 692). The decision in Federal Power Commission v. Hope Natural Gas Co. (Hope), 320 U.S. 591 (1944) states:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.

(Id. at 603). In reaffirming its Hope analysis, the United States Supreme Court observed in Duquesne Light Co. v. Barasch (Duquesne Light Co. II), 488 U.S. 299, 314 (1989) that "[o]ne of the elements always relevant to setting the rate under Hope is the return investors expect given the risk of the enterprise."

The determination of a fair rate of return thus requires the review of many factors, including: (1) the earnings which are necessary to assure confidence in the financial integrity of the utility and to maintain its credit standing; (2) the need to pay dividends and interest; and (3) the amount of the investment, the size and nature of the utility, its business and financial risks, and the circumstances attending its origin, development and operation. Lower Paxton Township. Moreover, the Commission's findings must be based upon substantial and competent evidence on the record before it, not upon speculation or hypotheses. Ohio Bell Telephone Co. v. Public Utilities Commission of Ohio, 301 U.S. 292 (1937); Octoraro Water Co. v. Pennsylvania Public Utility Commission, 38 Pa. Commonwealth Ct. 83, 391 A.2d 1129 (1978);

United States Steel Corp. v. Pennsylvania Public Utility Commission, 37 Pa. Commonwealth Ct. 195, 390 A.2d 849 (1978).

Two parties, PP&L and OTS, actively contested the rate of return question. The OCA and AARP stated cost of common equity positions and/or cost of capital positions without actively addressing the subject.

The following table summarizes PP&L's capital structure, cost of debt and preferred stock cost rate position (PP&L Ex. PRM 2, Sch. 1):

Capital Structure	Rate	Cost Rate
	%	%
Long-Term Debt	47.01	7.89
Preferred Stock	7.79	7.10
Common Equity	45.20	
	100.00	

The OTS and OCA state that they accept PP&L's proposed capital structure, debt cost and preferred stock cost rates (OTS St. 3 p. 6; OCA M.B. p. 60).

AARP contends that PP&L's proposal that the utility be made whole robs ratepayers of the benefits of the Act (AARP St. 1 pp. 63-64). Further, AARP states that PP&L's proposal absolves its management and stockholders of responsibility for above market costs (AARP St. 1 p. 64). AARP contends that PP&L wants to get full return of and on capital (AARP St. 1 p. 65). AARP does not set forth a clear picture of its position on PP&L's proposed capital structure, debt cost and preferred stock cost rates. AARP does, however, state that the common equity cost rate granted to PP&L in its last rate case is excessive (AARP M.B. p. 5). Primarily, AARP's position is to permit PP&L to get its capital out, without any return, and then all parties would be on equal footing (AARP St. 1 p. 76).

This recommendation finds PP&L's proposed capital structure and debt and preferred stock cost rates to be reasonable and are accepted by this recommendation. AARP does not set forth specific recommendations for PP&L's capital structure and debt and preferred stock cost rates.

1. Common Equity

The following table summarizes the common equity methodologies and claims of the parties:

Methodology	PP&L[1]	OCA[2]	OTS[3]	AARP[4]
	%	%	%	%
Discounted Cash Flow (DCF)	11.09		10.25	
Risk Premium	12.50			
Capital Asset Pricing Model (CAPM)	12.44			
Comparable Earnings (CE)	15.05			
Claim	12.75	10.00	10.25	00.00

1. PP&L M.B. p. 92. PP&L used its barometer group as a reasonableness check on PP&L Witness Moul's primary results based on PP&L Resources (PP&L M.B. p. 92).
2. OCA St. 1 p. 8.
3. OTS St. 3 pp. 6-10; OTS M.B. p. 25.
4. AARP M.B. pp. 5-7. AARP does not recommend a specific cost of common equity but rather states that the 11.5% proposed by PP&L's last case is excessive.

This Commission has in numerous recent decisions determined the cost of common equity primarily upon the DCF method and informed judgment. In countless proceedings, this Commission has upheld the validity of the DCF model as a primary tool for determining a fixed utility's cost of equity. See, e.g., Pennsylvania Public Utility Commission v. Western Pennsylvania Water Company, 68 Pa. PUC 343, 95 PUR4th 470 (1988); Pennsylvania Public Utility Commission v. Equitable Gas Company, 73 Pa. PUC 301 (1990); Pennsylvania Public Utility Commission v. West Penn Power Company, 73 Pa. PUC 454, 119 PUR4th 110 (1990); Pennsylvania Public Utility Commission v. Philadelphia Suburban Water Company, 75 Pa. PUC 391 (1991); Pennsylvania Public Utility Commission v. York Water Company, 75 Pa. PUC 134 (1991); Pennsylvania Public Utility Commission v. Metropolitan Edison Company, 78 Pa. PUC 128 (1993). Most recently, the Commission provided additional insight into its opinion regarding relying primarily on the DCF in its Qualified Rate Order for PECO Energy (Docket No. R-00973877), in pertinent part as follows:

> Regarding PECO's argument that the OTS' cost of equity determination is deficient because it relies solely upon the DCF method, the OTS contends that the ALJ appropriately found that, in numerous cases since 1988, the Commission has utilized the DCF method and informed judgment, citing Pennsylvania Public Utility Commission v. Philadelphia Suburban Water Company, 71 Pa. PUC 593, 623-632 (1989) and Pennsylvania Public Utility Commission v. Western Pennsylvania Water Company, 67 Pa. PUC 529, 559-570 (1988).
>
> In considering this matter, we note that, in numerous recent proceedings, we have determined a utility's cost of common equity using primarily the DCF (Discounted Cash Flow) method and informed judgment. Pennsylvania Public Utility Commission v. Roaring Creek Water Company, Docket No. R-00943177 (Order entered on May 31, 1995); Pennsylvania Public Utility Commission v. Philadelphia Suburban Water Company, supra. Regardless of the procedure employed in determining the fair rate of return for a utility, we exercise informed judgment. Pennsylvania Public Utility Commission v. West Penn Power Company, supra. Therefore, we reject PECO's argument that the OTS' reliance solely on the DCF methodology is improper in this proceeding (emphasis added).

Pennsylvania Public Utility Commission v. PECO Energy Company, R-00973877, slip op. at 56 (May 22, 1997).

OTS submits and we agree that the Pennsylvania Public Utility Commission precedent clearly supports a return on equity allowance based upon the DCF methodology. Most notably, on May 22, 1997, the Commission approved a DCF-determined common equity cost rate of 10 percent for PECO Energy Company, an electric utility. Pennsylvania Public Utility Commission v. PECO Energy Company, supra. (N.T. 1921-1922, August 28, 1997).

Pennsylvania Public Utility Commission, et al. v. Pennsylvania Power and Light Company, (Order entered September 27, 1995), the Commission quoted from Administrative Law Judge Christianson's Recommended Decision in rejecting Risk Premium and CAPM analyses as follows:

> [F[irst, we [i.e., the Commission] cannot accept that historic experienced earnings reflect the cost of capital. We know of no

> reputable analyst who would seriously argue that experienced earnings represent the cost of equity, except by pure happenstance. But, such is the inherent assumption of each methodology [Risk Premium and CAPM]. Second, we cannot accept, even assuming that historic experience earnings represented the cost of capital that the average premium of an equity investment over a fixed income investment over a period as long as 50 years, represents the investor required premium in today's and tomorrow's market.
>
> Accordingly, we conclude that we can place little credence in the results of these methodologies.

Further, Administrative Law Judge Christianson noted in his Recommended Decision in Pennsylvania Public Utility Commission v. Duquesne Light Company, 66 Pa. PUC 518 (1988), that the Commission declared "that the economic environment over lengthy time frames are not representative of current economic conditions and therefore does not produce realistic risk premium results." See, Pennsylvania Public Utility Commission v. Pennsylvania Power & Light Company, R-00943271 (Recommended Decision) at 163. Based upon the record evidence in PP&L's last base rate case, the Administrative Law Judge based his equity return recommendation in that proceeding primarily upon the DCF method and judgment (Id., at 163). In that proceeding, PP&L filed Exceptions to Administrative Law Judge Christianson's equity recommendation. The Commission ruled upon PP&L's Exceptions to the equity recommendation, in pertinent part, as follows:

> In its Exceptions, PP&L notes that the Commission in recent years based its rate of return allowances on the DCF Method. PP&L urges the Commission to "keep an open mind" on the various methods of calculating an equity return allowance. (PP&L Exceptions at 29).
>
> . . . . . .
>
> On the basis of the record before us herein, we conclude that there is no reason for us to divert from our practice of considering the DCF method exclusively for equity rate of return determination. Accordingly, PP&L Exceptions regarding this issue are denied (emphasis added).

(Mimeo at 184).

AARP position is simply that the 11.5% common equity cost rate is excessive. AARP does not make a cost of common equity recommendation. Therefore, AARP adds nothing positive to the cost of common equity question.

The following table summarizes the dividend yield and growth rate recommendations of the parties:

DCF	PP&L[1]	OTS[2]
	%	%
Dividend Yield	6.97 - 7.59	6.86 - 8.35
Preferred Stock	3.50	2.50 - 3.50

1. PP&L Ex. PRM 1 pp. 2-4.
2. OTS Ex. 3, Sch. 5 p. 1 and 2; OTS Ex. SR-3, Sch. 5 pp. 1 & 2.

The DCF methodologies will not be detailed in the body of this recommendation, but those interested can find PP&L's DCF methodology at PP&L Exhibit PRM 1 pages 2-4, and OTS' at OTS Statement 3 pages 17-23.

PP&L considers OTS' common equity cost rate to be inadequate for two reasons (PP&L M.B. pp. 93-94):

1. OTS' 10.25% cost of common equity rate significantly understates PP&L's cost of capital.
2. OTS' recommendation fails to produce an appropriate pre-tax interest coverage.

OTS considers PP&L's common equity cost rate to be inadequate for four reasons (OTS M.B. pp. 40-47):

1. PP&L employed three cost of common equity methods which are RP, CAPM and CE that this Commission has historically rejected.
2. PP&L's DCF result was inflated by making ex-dividend adjustments to dividend yields.
3. PP&L's DCF result was inflated by an 0.5 upward adjustment to the growth rate to reflect "market factors".
4. PP&L sole reliance upon PP&L's data during this time period is inappropriate.

It is obvious that no cost of common equity is without flaws. The DCF method generally accepted by this Commission is not perfect and is, in fact, flawed. Therefore, we will employ the DCF method analysis in this recommendation with full knowledge of its various flaws but adjusted to mitigate the effects of those flaws.

This recommendation finds an unadjusted dividend yield of 8.24%. The 8.24% unadjusted dividend yield is premised primarily upon OTS' spot dividend yields for PP&L.

PP&L Witness Moul states the following concerning his ex-dividend yield recommendation:

> Although the DCF model contains a variety of restrictive assumptions which severely limit its usefulness in the ratesetting context, the model has been employed with data for PP&L Resources and the Barometer Group using a dividend yield of 7.40% and 6.80%, respectively, based upon consideration of the 12-month average (i.e., 7.24% for PP&L Resources and 6.74% for the Barometer Group), 6-month average (7.44% for PP&L Resources and 6.81% for the Barometer Group), and 3-month average (7.31% for PP&L Resources and 6.75% for the Barometer Group) dividend yields shown on Schedule 5 pages 1 and 2. The dividend yields shown on the schedule reflect an ex-dividend adjustment. While the 7.40% and 6.80% dividend yields are not intended to represent a specific historical average, they are similar to the six-month averages. Using three different but generally acceptable formulas, the 7.40% and 6.80% dividend yields have been positioned in a forward-looking manner to arrive at the 7.59% adjusted dividend yield for PP&L Resources and 6.97% adjusted dividend yield for the Barometer Group.

We have not used PP&L's ex-dividend yield recommendation for the OTS reasons set forth at OTS Main Brief pages 45-46 and OTS Statement 3 pages 34 and 35. OTS contends the following:

1. No academic support for an ex-dividend adjustment to the dividend yield.
2. No financial publication provide ex-dividend adjusted dividend yields to investors.

Historically, we have averaged spot market data with market data of longer periods. The longer periods have usually been of 12 months and 6 months. We did this to offset any spot aberrations that may have occurred and to give some weight to the current market trends indicated by the spot price.

In this proceeding the OTS contends that PP&L's spot price is being overly influenced by the uncertainty surrounding the current filings (OTS St. 3 p. 20). PP&L's spot price dividend yield is 8.35% adjusted and 8.24% unadjusted (OTS Ex. 3, Sch. 5 p. 1).

Historic data and regulatory thinking are not relevant in the context of this proceeding's cost of capital. The future risks faced by PP&L in a deregulated market must, in my opinion, be greater than historic risk levels. Therefore, in this proceeding, we believe spot data is the best indication of PP&L's future capital costs. Further, the large difference between the spot data of PP&L and the barometer groups indicates that investors are requiring a higher cost of capital for PP&L because of the increased risk of deregulation.

We have considered the OTS spot adjusted dividend yields of 8.35% and 8.15% and we believe the May 30, 1997 spot dividend is more representative of the capital costs that PP&L may experience. We accept PP&L's argument that capital costs have moved upward during 1997 (PP&L St. 6-R pp. 3-5). Although OTS' August 1, 1997 spot dividend yield data is lower at 8.15%, we believe that the upward trend in 1997 indicates that the August 1, 1997 data may be an aberration. We recommend the use of 8.24% (8.35% spot dividend yields less half the growth adjustment).

The 8.24% unadjusted dividend yield adjusted for next period growth is 8.37% (unadjusted dividend yield of 8.24% times half the growth adjustment or 1.01565% equals 8.37%).

This recommendation finds a growth rate of 3.13%. We do not find the growth rate evidence of any party to be persuasive.

PP&L Witness Moul states the following concerning his adjusted growth rate recommendation:

> The growth component for PP&L Resources and the Barometer Group consists of 3.00% growth attributed to company-specific factors and 0.50% attributed to market-wide factors. The support for the company-specific growth rates may be found on Schedules 6 and 7. The elements considered were growth in earnings per share, dividend per share, book value per share, cash flow per share, and internal growth for PP&L Resources and the Barometer Group using historical and projected data typically considered by investors. While some DCF devotees would advocate that mathematical precision should be followed when selecting a growth rate (i.e., precise input variables often considered within the

confines of retention growth), the fact is that investors, when establishing the market prices for a firm, do not behave in the same manner assumed by the constant growth rate models using accounting values. Rather, investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their current dividend yield requirements.

To the company-specific growth rate of 3.00%, market-wide factors add 0.50% to the growth rate. Market-wide factors would include overall business conditions, monetary policy, fiscal and tax policy, the value of the dollar in foreign exchange, the balance of trade, all of which would comprise qualitative influences on investors' total return expectations. Qualitative factors must be considered because the fundamental analysis employed in reaching a growth rate forecast -- see Schedules 6 and 7 -- will not fully account for all market-wide factors because the quantitative growth analysis is company-specific. It is also not known to what extent securities' analysts incorporate market-wide factors into their estimates, or that analysts do this uniformly. In addition, as the electric industry adjusts to the new business environment, additional opportunities and risk will surely develop beyond the five-year horizon typically considered by the analysts' forecasts. the combination of both quantitative factors, as shown by company-specific variables, and qualitative factors, as shown by general investor sentiment, together form the foundation for the capital appreciation (i.e., capital gains yield) that investors expect from owning a common stock..

As noted above, there are a wide variety of factors that influence investor expected returns which are not linked to company-specific performance. In an article in Standard & Poor's <u>The Outlook</u> (February 21, 1996), the relative valuation of common stocks was explained in part by qualitative factors (i.e., favorable psychology). Recognition of market-wide factors is needed to synchronize the growth rate in the DCF with the stock price which includes both company-specific factors and general market sentiment which includes relative P/Es, dividend yields, interest rates, the supply of stocks, etc. Therefore, for the purpose of this case, a modest 0.5% growth rate for market-wide factors has been added to the growth rate shown by company-specific variables. By considering both company-specific and market-wide factors, a 3.50% growth rate is warranted for PP&L Resources and the Barometer Group.

> Recognition of market-wide qualitative factors represents a reasonable adjustment to the DCF growth rate. It has been demonstrated by the Goldman Sachs study that 38% of the rise in stock prices in the 1980s occurred due to unknown factors. As to the proposition that such qualitative factors are already reflected in stock prices under the efficient market hypothesis, it is the need to synchronize the growth rate employed in the DCF with the growth rate reflected in stock prices that necessitates recognition of qualitative factors. That is to say, while stock prices may reflect all information concerning both market-specific growth. To make the DCF model at all useful, the growth rate component combined with the dividend yield must provide a result that conforms with the mix of current returns from dividends and long-term returns from capital gains.

(PP&L Ex. PRM 1 pp. 3-4).

Concerning PP&L Witness Moul's upward adjustment of 0.50% to his 3.00% growth ratio, OTS contends that Witness Moul's growth rate estimate of 3.00% accounts for "market factors" (OTS St. 3 p. 35). OTS states that an examination of the Company's exhibits in this proceeding demonstrates that Witness Moul has relied upon "analysts projections" as they appear on Schedule 7 of PP&L Exhibit PRM 2. Most important is the fact that "analysts projections" are based upon "market factors" listed on page 3 of PP&L Exhibit PRM 1 (Id., at 35). Consequently, any additional and independent recognition of "market factors" by Mr. Moul in addition to the "analysts projections" is a double count. Further, OTS Witness Deardorff notes that PP&L Witness Moul failed to provide evidence that market factors result in positive impact on the growth rate for the electric companies (OTS St. p. 35). OTS contends that Witness Moul concedes that market factors could possibly result in negative growth (PP&L St. 6-R pp. 17-18). OTS states that Witness Moul, without any support, suggests that such negative growth "only adds to investor expectation of higher stock prices in an exuberant "bull" market (PP&L St. 6-R p. 18). We agree with OTS that the growth rates do consider market factors and that no adjustment for market factors is required.

We have judgmentally decided upon the midpoint of the proposed growth rate range or 3.13%. The growth rate range of 2.75% to 3.50% is based on OTS' proposed growth rates (OTS Ex. 3, Sch. 5 pp. 1 & 2; OTS Ex. SR-3, Sch. pp. 1 & 2).

The growth rate range is based upon OTS' data for the period ending May 30, 1997. As indicated in my dividend yield discussion, we believe the May 30, 1997 data is the best indicator of the capital cost PP&L will face in the future. The range includes PP&L's growth rate claim with and without PP&L's "market factor" adjustment. The use of the midpoint of the range should mitigate the market aberrations and bias of the witnesses.

Therefore, this recommendation finds a DCF common equity cost rate based on our previous discussion of 11.50% (adjusted dividend yield of 8.37% plus a growth rate of 3.13% which equals a DCF cost rate of 11.50%).

Summary of Recommendation

Capital Structure	Ratio %	Cost Rate %	Weight Cost %	Tax Savings On Debt %	After Tax Weighted Avg. Cost of Capital %
Long-Term Debt	47.01	7.89	3.71	1.54	2.17
Preferred Stock	7.79	7.10	.55		.55
Common Equity	45.20	11.50	5.20		5.20
	100.00		9.46		7.92

Under this recommendation's 9.46% overall rate of return, interest coverage levels, a rate of return testing technique, on an after income tax basis is 2.5 times. PP&L's proposed after income tax interest coverage level is 2.5 times.

C. Regulatory Assets And Liabilities

PP&L included in its calculation of stranded costs the present value (as of January 1, 1999) of its generation-related net regulatory assets. The Company initially claimed $383,911,000 for such assets in its Restructuring Plan filing. PP&L Exh. JRS 1, Tab B, p. 1 of 117. PP&L subsequently revised its claim during the course of this proceeding to $354,326,000, a reduction of $29,585,000. PP&L Exh. JRS 1A, p. 1. As explained in detail below, PP&L's claim is supported by extensive record evidence. Several parties, however, propose adjustments to various elements of the Company's claim. The parties' recommendations have been considered and are substaintially rejected. See PP&L M.B. pp. 98-122, OTS M.B. pp. 49-63.

1. Unrecovered Energy Costs

On December 13, 1996, the Company filed an Application with the Commission to roll its Energy Cost Rate ("ECR") and State Tax Adjustment Surcharge ("STAS") into base rates, in response to Section 2804(4) of the Act, 66 Pa.C.S. § 2804(4), which establishes price caps on the Company's rates. The Company's Application requested Commission permission to defer as a regulatory asset: (1) unrecovered energy costs as of December 31, 1996; and (2) a normalized level of estimated future on-going energy costs. On December 19, 1996, the Commission issued a Tentative Order at Docket Nos. P-00961131 and R-00963842 approving PP&L's Application ("Tentative Order"). PP&L St. 3, pp. 9-11.

The Tentative Order created two regulatory assets, both of which are reflected in the Company's Restructuring Plan filing. First, PP&L is claiming the actual undercollection of $17.2 million in energy costs as of December 31, 1996. Second, the Company seeks to include in its stranded cost calculation approximately $31.2 million of normalized, on-going future energy costs on an annual basis. PP&L St. 3, p. 11; PP&L St. 3-R, p. 19.[34]

OCA witnesses La Capra and Catlin, and PPLICA witness Kollen argue that PP&L has failed to support its claim of $31.2 million on an annual basis for future on-going energy costs. OCA St. 1, pp. 6-8; OCA St. 3, pp. 5-7; PPLICA St. 3, pp. 17-21. In fact, PP&L Exhibit JMK 5 provides a calculation of the five-year average of actual energy costs incurred by the Company during the period 1992 through 1996. This five-year average amount demonstrates that PP&L's estimated future on-going energy costs will exceed the level of energy costs rolled into base rates on January 1, 1997 as a result of the Commission's December 19, 1996 Order by approximately $31.2 million annually. PP&L Exh. JMK 5.

Based on actual energy costs for the period January 1, 1997, through June 30, 1997, the Company already has under-recovered $22.5 million of the energy costs included in its base

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[34] PP&L originally estimated that its normalized, future on-going energy costs would equal approximately $31.5 million on an annual basis. PP&L St. 3, p. 11. The Company subsequently reduced this estimate to $31.2 million based on updated information. PP&L St. 3-R, p. 19.

rates. PP&L St. 3-R, pp. 19-20.[35] The Company expects to underrecover its energy costs by approximately $36 million in 1997 and $67 million in 1998. PP&L St. 3-R, p. 19, PP&L Exh. JMK 6.

Mr. La Capra contends that PP&L overstates its under-recovery of future on-going energy costs for the years 1997 and 1998 because the Company's claim is not based on a mills per-kilowatt-hour basis. OCA St. 1, p. 7. Mr. La Capra is completely in error. As explained by Mr. Kleha, the calculations supporting the Company's claim (Exhibits JMK 5 and 6) in fact reflect a mills per-kilowatt-hour energy cost determination. PP&L St. 3-R, pp. 20-21.

Mr. Catlin also suggests that PP&L's claimed underrecovery of on-going energy costs is overstated because PP&L is earning more than its required return on common equity. OCA St. 3, pp. 6-7. Mr. Catlin is incorrect. PP&L's pro forma rate of return on common equity was 11.42% for the year ended December 31, 1996, below the 11.50% allowed by the Commission in PP&L's most recent base rate case in 1995. PP&L St. 3-R, p. 22.[36]

PP&L notes that PECO's claim for future understated projected energy costs in its Restructuring Plan proceeding was denied by the Commission. PECO Order, p. 71; Order on Reconsideration, p. 11. Nonetheless, PP&L respectfully submits and we agree that the Commission's resolution of this issue in the PECO proceeding should not be dispositive of its claim in this case. These costs are "known and measurable" under traditional PUC practice, were deferred and properly recorded as a regulatory asset pursuant to PUC Order. We find them to be properly recoverable under the Act.

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[35] In its Restructuring Plan proceeding, PECO claimed $22 million for annual deferred fuel expense through December 31, 1998, and $22.7 million annually through December 31, 2005, to recover the amount by which its average energy costs rolled into base rates understate its estimated going-forward energy costs.

[36] The calculation and data submitted by the Company in support of its claim are similar to the information PP&L consistently provided to the Commission to support its energy cost rate filings. Tr. 1108 (8/20/97). Thus, Messrs. Kollen and Catlin are incorrect in stating that the Company failed to reflect revenues in its calculation of future under-recovered energy costs. PPLICA St. 3-S, p. 21; OCA St. 3-S, p. 4.

2. Employee Transition Costs And Pension Plan

The Company's claimed stranded costs reflect estimated additional severance and pension costs that PP&L expects to incur between 1997 and 2001 as a result of its projected decline in the number of employees as the Company prepares for a competitive market. PP&L St. 8, pp. 25-26. PP&L's estimated severance and pension expenses are as follows: 1997: $5,014,000 1998: $6,782,000; 1999: $4,157,000; 2000: $3,118,000; 2001: $4,211,000. PP&L Exh. JRS 1, Tab F, p. 40. The Company calculated a five-year amortization of the costs incurred in each year, and included in its calculation of stranded costs, the net present value of the recovery of these deferred costs that are allocable to the generation function ($17.106 million). PP&L St. 8, pp. 25-26.

The OCA argues that the claimed employee transition costs for 1997 and 1998 should be excluded. OCA St. 3, p. 10. This adjustment would reduce the balance of regulatory asset for employee transition costs by $10.793 million. The OCA also contends that incremental pension benefits should be excluded because such benefits will not result in added out-of-pocket costs due to the overfunded position of PP&L's pension plan. This adjustment would further reduce the regulatory asset by $8.003 million. As a result of these two adjustments, the OCA recommends that the Commission allow only $3.483 million of future on-going employee transition costs as a regulatory asset. OCA St. 3, p. 11.

Similarly, PPLICA asserts that PP&L's claimed future on-going employee transition costs are speculative, and that the Company failed to reflect normal employee attrition in its calculations. PPLICA St. 3, pp. 22-23. Even if the Commission "conceptually" adopts this regulatory asset, PPLICA argues that such asset should be valued at $5.502 million, the net present value of future cash outlays. PPLICA St. 3, p. 23.

The OCA and PPLICA adjustments are inappropriate and are rejected. See PP&L M.B., pp 102-104.

3. Taxes Other Than Income

PP&L included Taxes Other Than Income in its calculation of stranded costs. The Company's claim includes two components: (1) capital stock taxes; and (2) Public Utility Realty

Tax ("PURTA").[37] PP&L calculated the actual amount of capital stock and PURTA taxes in 1996 applicable to fossil and nuclear generation facilities. The Company then escalated the 1996 taxes at the rate of inflation (2.5 percent) over the life of each generating facility. PP&L St. 8-R, p. 35; PP&L Exh. JRS 1, pp. 4-5.

OTS, OCA and PPLICA each oppose the Company's claim. OTS and PPLICA argue that capital stock taxes should remain constant over the life of each generating facility, but that PURTA taxes should decline in relation to the decline over time in net plant balance resulting from depreciation. OTS St. 2, pp. 16-23; PPLICA St. 2, pp. 50-51. We adopt the OTS' adjustment which reduces PP&L's nuclear generation-related stranded costs by $280.7 million, and its fossil generation-related stranded costs by $66.1 million. OTS St. 2, pp. 22-23, OTS M.B. 49-54.

4. Fossil Plant Decommissioning

PP&L's calculation of stranded costs includes $315.867 million attributable to the costs of decommissioning its various fossil generating units.[38] PP&L escalated each fossil plant's decommissioning costs at a 2.5 percent annual rate of inflation to the end of its book life. The Company assumed that it would incur decommissioning costs over a three-year period -- 40 percent in the year each plant is retired, 40 percent the following year, and 20 percent the next year. PP&L Exh. JRS 1, p. 8.

The OCA and PPLICA recommend that the Commission exclude the Company's claimed costs in their entirety (OCA St. 1, p. 18, PPLICA St. 3, pp. 30-35, PPLICA St. 3-S, p. 31).

In its recent Order in the PECO Restructuring Plan proceeding, the Commission denied a similar claim by PECO for $126.6 million for costs associated with the decommissioning of its fossil generating facilities. The Commission concluded that PECO's claimed expenses were unsupported and speculative and are prohibited by Pennsylvania law. PECO Order, pp. 49-50. We turn to the Act for guidance

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[37] This item is not a regulatory asset. It is a cost of operation included in the calculation of revenue under regulation in PP&L's regulatory model and as an offset to market revenue in the asset value model.

[38] This item is not a regulatory asset. It is an operating cost included in revenue order regulation in PP&L's regulatory model and as an offset to market revenue in the asset value model.

First, Section 2803 of the Act clearly defines "transition or stranded costs" as including "retirement costs attributable to the utility's existing generating plants other than the costs defined in Paragraph (1)," which refers to the recovery of nuclear generating plant decommissioning costs. 66 Pa.C.S. § 2803. Thus, fossil decommissioning costs which are incurred to retire existing fossil generating facilities are defined by the Act as allowable "transition or stranded costs" and must be included.

Second, PPLICA argues that the Company's claimed costs are speculative and unsupported. Specifically, Mr. Kollen asserts that PP&L's claim derives from a fossil decommissioning study performed by TLG Services which is based on three erroneous and speculative assumptions: (1) PP&L's fossil generating facilities will be decommissioned while owned and controlled by the Company; (2) the facilities will be retired on the dates indicated in the study; and (3) the facility sites will be restored to "greenfield" conditions. PPLICA St. 3, pp. 31-32. Similarly, in denying PECO's claim for fossil decommissioning costs, the Commission concluded that there was no evidence "that any particular fossil plant will in fact have to be decommissioned at all, when such decommissioning might occur, the extent of decommissioning that will be required, the future use of the plant and its site, or the cost of the decommissioning found to be needed." See also PECO Order, p. 92.

The concerns held by PPLICA and the Commission with respect to this issue are misplaced in this case. PP&L in fact has submitted substantial evidence in this proceeding which fully supports its estimated future fossil decommissioning costs. Indeed, past industry experience suggests that PP&L's claim may be understated, as decommissioning estimates generally have proven to be much lower than the actual costs incurred. PP&L St. 3-R, p. 34. Mr. Kollen conceded on cross-examination that the TLG study is very similar to other studies relied upon by the Commission to establish allowable levels of nuclear decommissioning expense. Tr. 1486 (8/25/97). Moreover, Mr. Kollen agreed on cross-examination that the nuclear decommissioning study performed by TLG and relied upon by the Commission in PP&L's last base rate proceeding contained the same types of assumptions that Mr. Kollen now attacks in the TLG fossil decommissioning study in this proceeding. Tr. 1486-88 (8/25/97). PP&L submits that the record evidence fully supports its claimed level of fossil decommissioning expenses.

Finally we believe that the Superior Court's decision in *Penn Sheraton Hotel v. Pa. P.U.C.,* 198 Pa. Super. 618, 184 A.2d 324 (1962), does not prohibit recovery of projected fossil decommissioning costs. PPLICA St. 3, pp. 33-34; PECO Order, pp. 91-92. *Penn Sheraton* fully supports the recovery of fossil decommissioning costs; the only point at issue was the timing of that recovery.

Penn Sheraton prohibited advance recovery of retirement costs but permitted recovery of actual retirement costs.[39] As explained by Mr. Kleha, PP&L's estimate of stranded generation-related capital and operating expenses was calculated utilizing the revenue requirements methodology contemplated by the Act. PP&L St. 3-R, pp. 31-32. Using this methodology, the Company included in its calculation the costs of decommissioning existing fossil generating facilities that would be recoverable under traditional rate regulation at the end of the lives of those facilities. Thus, consistent with *Penn Sheraton*, PP&L's claim reflects its projected fossil decommissioning costs at the point in time when they actually would be incurred. PP&L St. 3-R, p. 32.

Finally, while OTS does not oppose PP&L's proposed stranded cost recovery of fossil decommissioning costs, Mr. Gruber recommends that the Commission require the Company to place all amounts recovered in a separate, non-qualified trust fund that would be accessible only as fossil decommissioning costs are actually incurred. OTS St. 1, p. 15.

As set forth by PP&L in this matter, they are claiming a net present value of decommissioning expenses for fossil fuel generation plant of $1,074,961,000. This number is the sum of the Company's fossil decommissioning found on Pages 20-23 of Schedule 117 in PP&L Exhibit JRS - 1.

The Company has included the cost of decommissioning each of its fossil fuel power stations in the stranded cost analysis as a necessary future revenue stream. These dollars have been valued to 1999 dollars and their recovery has been included in the Competitive Transition Charge (CTC).

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[39] Moreover, to the extent *Penn Sheraton* is read to prevent stranded cost recovery of retirement costs it is patently inconsistent with the Act, which clearly permits recovery of these retirement costs.

OTS has made no adjustment to the level of the Company's fossil fuel decommissioning claim. OTS does have a position concerning the treatment of the decommissioning claim after the money has been collected.

With regard to the Company's claim for fossil fuel decommissioning, OTS witness Mr. Gruber has testified that if the Commission allows the Company to include the fossil fuel decommissioning claim in its stranded cost analysis, then OTS recommends that the Company be ordered to segregate the money collected for fossil fuel decommissioning in a separate non-qualified trust fund. This fund would not be accessible to the Company until it actually decommissions a fossil fueled power plant. (See OTS M.B. pp. 49-54, OTS Statement No. 1, Pages 15-16)

Mr. Gruber further testified that if the Company sold a fossil fuel power station in the future, the fund would remain in the custody of the Company. When the power station that has been sold is decommissioned, the Company would disburse the appropriate amount of funds from its decommissioning fund to the entity responsible for the decommissioning. Mr. Gruber also testified that the Company would only be responsible for the amount of decommissioning expense it had collected while associated with that power plant, to the extent that the cost is greater than the amount in the fund, the Company who owns the station would be responsible to make up the difference.

Mr. Gruber's recommendation is appropriate and we will recommend the adjustment.

5. Nuclear Plant Decommissioning

In calculating the annual revenue requirement for nuclear generation, the Company included the amount it is recovering in annual nuclear decommissioning expense through existing retail and wholesale rates, adjusted to the appropriate PUC-jurisdictional amount. PP&L St. 8, p. 11.[40] Currently, PP&L is recovering approximately $9.5 million per year in jurisdictional rates for nuclear decommissioning costs. PP&L St. 3, p. 15. PP&L's stranded cost claim reflects the net present value of after-tax future annual nuclear decommissioning expense accruals over the remaining life of the Company's nuclear facilities. As a preferred alternative,

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40 This item is not a regulatory asset. It is an operating cost included in the calculation of revenue under regulation in PP&L's regulatory model and as an offset to market revenue in the asset value model.

however, PP&L proposes to recover its nuclear decommissioning costs over the remaining life of its nuclear generating facilities, through distribution charges on a per kWh basis. PP&L St. 3, p. 14; PP&L St. 3-R, p. 28.

Two concerns underlie PP&L's proposal. First, there is some question as to whether the transition to full competition will ensure the adequate recovery of nuclear decommissioning costs. Section 2808 of the Act, 66 Pa.C.S. § 2808, provides electric utilities "an opportunity" to recover stranded costs through the CTC, including nuclear decommissioning costs that may not be recoverable in a competitive generation market. Thus, PP&L will have to fund a substantial amount of its nuclear decommissioning costs using revenue from market rates. There is no assurance, however, that such market rates will be sufficient to satisfy PP&L's nuclear decommissioning funding obligations. PP&L St. 3, p. 12.

Second, there is a risk that the transition to full competition could subject PP&L to substantial financial qualification requirements under Nuclear Regulatory Commission ("NRC") regulations. Specifically, NRC regulations exempt "electric utilities" from the requirement to provide additional financial assurance for nuclear decommissioning (e.g., insurance or surety bond) beyond establishment of an external sinking fund. "electric utilities" are defined as "any entity that generates or distributes electricity and which recovers the cost of electricity, either directly or indirectly, through rates established by the entity itself or by a separate regulatory authority." 10 C.F.R. § 50.2

Under traditional cost-of-service rate regulation, PP&L plainly satisfies the NCR's definition of "electric utility" because its rates are set by the Commission. PP&L currently is authorized to recover its estimated future nuclear decommissioning costs in rates over the remaining life of its nuclear generating facilities, and all recovered amounts are placed in an external trust fund. However, the Act requires that all generation-related costs, including those related to PP&L's nuclear generating facilities, be removed from traditional rate regulation. The Company's proposal to recover its claimed costs through a distribution charge is designed to address both of these concerns. PP&L's proposal will ensure adequate nuclear decommissioning funding and will provide for the recovery of such costs through rates established by the Commission. PP&L St. 3, pp. 14-15.[41]

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[41] The charge that would result from PP&L's proposal would be extremely small and would have a

PPLICA and the Environmentalists oppose the Company's proposal. First, PPLICA contends that PP&L's proposal to recover nuclear decommissioning costs on a per kWh basis is inconsistent with its treatment of such costs in its last base rate case. PPLICA St. 1, pp. 55-56. The record evidence plainly shows that the Company unbundled costs in this case using the same demand allocators utilized in its last base rate proceeding. Thus, PP&L's proposed unbundled tariff rates reflect nuclear decommissioning costs allocated among customer classes on a demand basis. The Company proposes to recover these demand-allocated costs on a per kWh basis, which is the same method currently used to recover such costs through fully regulated rates. PP&L St. 3-R, pp. 28.

The Environmentalists oppose PP&L's proposal to extend the CTC, and recommend that the Commission consider "the benefits of an incentive framework for nuclear decommissioning costs, in which risks are shared between the Company and its customers." Environmentalists St. 2, p. 28. This proposal is inconsistent with the Act, which clearly states that the PUC "shall" provide for recovery of nuclear decommissioning costs. 66 Pa.C.S. § 2808(c)(1). See also PP&L St. 3-R, pp. 29-30.

Finally, it should be noted that PPLICA initially opposed the Company's proposal to recover nuclear decommissioning expenses as a distribution-related component of its delivery charges, claiming that PP&L would recover such expenses twice. PPLICA St. 3, p. 39. In rebuttal, PP&L explained that it would exclude nuclear decommissioning costs from those recovered through the CTC if the Commission adopts the Company's proposal. PP&L St. 3-R, p. 29. Based on this clarification, PPLICA agreed that PP&L's proposal would not result in the double recovery of nuclear decommissioning costs. PPLICA St. 3-S, p. 33.

The Commission already has approved a similar proposal for the recovery of nuclear decommissioning costs in the PECO case. PECO's post-1998 decommissioning costs were reflected in its calculation of stranded costs as a future operating expense affecting the market value of its facilities. With respect to its claimed underrecovered costs, PECO proposed two collection methods. PECO first suggested recovering its costs through the CTC as a stranded

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minimal impact on customers. For example, the Company currently collects approximately $9.5 million per year in rates for nuclear decommissioning costs. For the average residential customer using 500 kWh per month, this equals approximately $0.03/kWh, which is approximately $0.15 per month and less than $2.00 per year.

cost. In the alternative, PECO proposed to recover its claimed costs as an annuity through regulated transmission and distribution rates. The Commission adopted PECO's second proposal, finding that it would ensure that the amounts recovered would continue to qualify for favorable IRS and NRC treatment. PECO Order, p. 78-80.

In the instant case, PP&L's proposed distribution charge for the recovery of its estimated nuclear decommissioning costs is similar to the mechanism approved by the Commission in the PECO proceeding. As explained above, the Company's proposal will ensure that it fully recovers its nuclear decommissioning costs over the remaining life of its facilities, and that it retains its exemption from burdensome NRC financial assurance requirements. PP&L's proposal is consistent with the Commission's decision in the PECO case and we recommend that it be adopted.

6. Department Of Energy Assessments

The Energy Policy Act of 1992 ("Energy Act") establishes an assessment on utilities, including PP&L, owning nuclear power operations to provide funds for the decontamination and decommissioning of the Department of Energy's ("DOE") uranium enrichment facilities. Under the Energy Act, this charge is assessed over a 15-year period, and is deemed a necessary and reasonable current cost of fuel that is fully recoverable in rates in the same manner as other fuel costs. PP&L St. 8, p. 24.

PP&L determined the amount of DOE assessment costs that would be recovered annually through existing rates, and included the present value of the PUC-jurisdictional portion of this amount in its calculation of stranded cost. PP&L St. 8, p. 24. The OCA and PPLICA recommend that the Commission disallow the Company's claim in its entirety, noting that PP&L already reflected this assessment in its Restructuring Plan filing as a component of fuel expense. OCA St. 3, p. 7; PPLICA St. 3, pp. 24-25. In response, the Company eliminated all DOE assessment amounts from the fuel expense component of its generation-related costs, which reduced PP&L's stranded costs by approximately $17 million. PP&L St. 8-R, pp. 56-57. This correction fully addresses the OCA's and PPLICA's concerns.[42] PP&L's proposed recovery of

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[42] On surrebuttal, Mr. Kollen argued that PP&L failed to correct the double-counting error. PPLICA St. 3-S, p. 26. As explained by Mr. Schadt, the DOE assessment was removed from the generation-related stranded cost calculation, and was retained as a regulatory asset. Tr. 1545-46

DOE assessment costs as a regulatory asset, therefore, is appropriate and we recommend it be approved.

7. Susquehanna Deferred Refueling Expenses

PP&L's stranded cost calculation includes a claimed regulatory asset for incremental maintenance costs incurred during refueling and inspection outage at PP&L's Susquehanna Steam Electric Station ("SSES"). These costs are deferred and amortized from the end of the outage until the next scheduled refueling and inspection outage is completed. The Company determined the annual recovery that would occur through existing rates and included in its stranded cost calculation $7.996 million on a present value basis at December 31, 1998 for the PUC-jurisdictional portion of these costs. PP&L St. 8, p. 25.

In its filing, the Company has claimed SSES Deferred Refueling Costs as an individual item in its claim for regulatory assets. By way of further discussion, the deferred refueling costs represents incremental maintenance costs incurred during refueling and inspection outages which are deferred and subsequently amortized from the end of the outage until the next scheduled refueling and inspection outage is complete. PP&L Exh. JRS-1, at 12-13; OTS St. 2 at 13-14.

The basis for the Company's claim is its annual PaPUC jurisdictional amortization for both costs for 1999; however, OTS witness Reed has recommended that the Company's claim for stranded costs relating to Regulatory Assets exclude the amounts associated with deferred refueling costs. OTS St. 2 at 14. As Mr. Reed explained, deferred refueling costs are not regulatory assets that are recoverable through a traditional amortization, but are typical ongoing expenses that, in a regulatory environment, are recoverable in base rates at normalized levels. Id., at 14.

In rebuttal, PP&L suggests that since the Company did propose to recover deferred refueling outage costs in a period after they were incurred, it was necessary to accumulate and defer the actual costs of the first refueling outage on the Company's books and amortize this amount over the period it was to be recovered in rates. PP&L St. 8-R at 46. The Company supports its argument by claiming that an Administrative Law Judge approved PP&L's request to defer its refueling costs on the Company's book and amortize them for book purpose.

(8/26/97). The error clearly was corrected; Mr. Kollen is mistaken.

Additionally, according to PP&L witness Schadt, the Commission at Docket No. R-822169, agreed with the Administrative Law Judge and approved the Company's request to defer refueling outages on the Company's books of account. Id., at 46. Consequently, according to the Company on rebuttal, PP&L has been utilizing this deferral method for both SESS units since 1983.

Since the Company, in its rebuttal, has relied upon a Commission's Opinion and Order at Docket No. R-822169, which is Pennsylvania Public Utility Commission v. Pennsylvania Power & Light Company, 55 PUR4th 185, 228-229 (1983), there is a critical need to review this case carefully and in its entirety. Upon reviewing this case in question, OTS submits and we agree that the Commission in its Order approved PP&L's request to accrue and defer first refueling costs of Unit 1. However, that approval was specifically addressed to the costs of the first Unit 1 outage in 1984 and was for book purposes only. OTS St. SR-2 at 7. Accordingly, no allowance was made for their recovery in rates. The Commission's Opinion and Order simply preserved the Company's right to claim the first Unit 1 outage costs in a future rate proceeding. Id., at 7. PP&L's argument suggesting that the case at Docket No. R-822169, supporting the recovery of Susquehanna deferred refueling costs, in this instant proceeding is incorrect. Moreover, the Commission's Opinion and Order in PP&L's most recent base rate case at Docket No. R-00943271, clearly did not institute an annual amortization for which the Company would be entitled to full recovery, but establish a normalized annual level of expense applicable to the deferred refueling costs that would be included in rates. Simply put, there is not support in Commission Opinions and Orders for the position articulated by PP&L regarding claiming deferred refueling costs as regulatory assets for stranded costs purposes.

On cross-examination, PP&L witness Schadt acknowledged that he, as the Company's expert witness in this area, did not understand for ratemaking purposes, the difference between amortization and normalization. (Tr. 1588-August 26, 1997). This admission is key as to why the Company has made a mistake in claiming deferred refueling costs as a regulatory asset. OTS submits that in order to fully comprehend the issue of whether it is proper for the Company to claim SESS Deferred Refueling Costs as stranded regulatory assets, the expert witness must understand the difference between normalization and amortization for ratemaking purposes. Obviously, by Mr. Schadt's own admission, he did not understand the difference between normalization and amortization. Interestingly, after OTS witness Reed had provided definitions of amortization and normalization in his direct testimony, Mr. Schadt continued not to understand the difference between the two, yet he appeared as the Company's expert witness on whether PP&L should recover SESS Deferred Refueling Costs as stranded regulatory assets.[43]

As Mr. Reed explained, normalization is a ratemaking concept that describes the transformation of an operating expense that recurs at irregular intervals and in irregular amounts into a "normal" annual test year expense allowance. OTS St. 2 at 15. Amortization is an accounting concept that extinguishes an atypical, nonrecurring expense over a pre-determined number of years by charging to operations a pro rata share based on the selected amortization period. Id., at 15. OTS submits that it is critical to understand that recovery of normalization expenses do not extend over a period of years and therefore claims for unrecovered normalized expenses in subsequent proceedings cannot exist and must be disallowed. Id ., at 15. In contrast, an amortization allowance could be claimed in succeeding proceedings as long as there is a remaining unamortized balance. Id., at 15. In applying the definition of normalization and amortization to the issue of deferred refueling costs, OTS submits, and the Commission's Order supports, the conclusion that the Commission did not allow PP&L to amortize the full amount of deferred refueling costs in the Company's last base rate proceeding. The Commission allowed PP&L to reflect a claim for deferred refueling expenses in annual O & M at a normalized level, therefore PP&L's attempt to claim deferred refueling costs as a regulatory asset in this proceeding violates the definition of normalization and should not be allowed.

Accordingly, the effect of disallowing deferred fuel, along with the associated rate case expense reduces the net present value relative to regulatory assets from $383,911,000 to $375,384,000, which results in a reduction of $8,527,000.

8. Earnings On Recovered SFAS 106 Costs

In its Final Order at Docket No. R-00943271, the Commission authorized PP&L to recover the full PUC-jurisdictional portion of expenses attributable to the adoption of Statement of Financial Accounting Standards 106 ("SFAS 106"). SFAS 106 requires PP&L to record the liability associated with post-retirement benefits on an accrual basis (i.e., at present value), rather

[43] Mr. Schadt also appeared on behalf of the Company as to whether PP&L should recover its 1994 Rate Case Expense as a stranded regulatory asset.

than on a pay-as-you-go or cash basis. The Company's current rates recover the full SFAS 106 costs applicable to PUC-jurisdictional customers, including approximately $11 million in excess of PP&L's current cash payment obligation for post-retirement benefit claims to recover the transition obligation or accrued liability that existed as of January 1, 1993, the date PP&L adopted SFAS 106. The transition obligation is being amortized over 20 years. PP&L St. 8, p. 22; PP&L St. 8-R, pp. 41-42.

The Company determined the annual recovery of SFAS 106 costs that would occur under existing rates and included the present value of the PUC-jurisdictional portion of the generation-related amount in its calculation of stranded costs. PP&L St. 8, p. 22. PPLICA generally accepts the Company's claim, but recommends that the Commission recognize a regulatory liability for the interest earned by trust funds established by PP&L to fund post-retirement benefits other than pensions. PPLICA St. 3, pp. 26-29. In PPLICA's view, this regulatory liability should be used to offset PP&L's claimed regulatory asset.

> PPLICA's proposed adjustment should be rejected. The interest identified by Mr. Kollen already is utilized to offset or reduce the projected cost of post-retirement benefits other than pensions. PP&L St. 8-R, p. 40.

PPLICA relies on the Commission's recent Order in the PECO Restructuring proceeding to support its recommendation in this case. In that proceeding, the Commission adopted PAIEUG witness Kollen's proposed regulatory liability for SFAS 106 trust fund earnings. The Commission stated:

> Under traditional ratemaking, consumers would receive [a] credit against future expenses for these earnings. As such, they should be treated as a regulatory liability at this time. Since generation will no longer be under traditional cost-based regulation, customers would lose these credits if we did not allow them in this proceeding. PECO Order, p. 77.

As a result of this adjustment, the Commission reduced PECO's total stranded costs by $150.861 million. *Id.* See Order on Reconsideration, pp. 13-14.

The Commission's decision in the PECO proceeding is not dispositive in this case. In calculating its claimed SFAS 106 costs, PECO apparently did not credit customers with the earnings on its SFAS 106 trust fund. Instead, PECO argued that "it should be permitted to retain trust fund earnings in order to account for future inflation and cost escalation . . . ." Order on Restructuring, p. 13. In this case, PP&L has fully reflected its SFAS 106 trust fund earnings in its calculation of stranded costs. As explained above, those earnings were utilized to reduce PP&L's claimed SFAS 106 expenses. The Company's claim, therefore, is clearly distinguishable from that addressed by the Commission in the PECO proceeding.

9. SFAS 109 (Investment Tax Credit)

With the change in Federal tax laws that allowed PP&L to take advantage of investment tax credits ("ITCs"), the Company elected to defer recognition of these credits as income by recording a liability for accumulated deferred ITCs. The amortization of accumulated ITC's, along with the related income tax effect, reduces the cost-of-service (and thus customer rates) over the lives of the assets that produced the ITCs. As a result of the adoption of Statement of Financial Accounting Standard No. 109 ("SFAS 109"), PP&L recorded a deferred tax asset to reflect the income tax effect of the accumulated deferred ITCs, and a regulatory liability (i.e., an amount owed to customers) to reflect the ratemaking treatment of the tax effect. This regulatory liability is equal to the reduction in income tax expense that will need to be recovered from customers as the balance of accumulated deferred ITCs is amortized to reduce the cost-of-service over the remaining lives of the underlying assets. PP&L St. 8, pp. 28-29.

In its Restructuring Plan filing, PP&L utilized the present value of the ITC regulatory liability to reduce or offset the present value of regulatory assets in calculating the level of its stranded costs. The methodology used by the Company to reflect the effect of the ITC regulatory liability is not opposed by any party in this proceeding.[44]

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[44] In fact, PPLICA took the somewhat unusual step of submitting detailed testimony in support of PP&L's claim. PPLICA St. 3, pp. 9-13.

10. Retirement Of Generating Plant

In calculating its stranded cost claim, PP&L utilized the same deactivation dates for its generating facilities that were approved by the Commission in the Company's most recent base rate case at Docket No. R-00943271.[45] Specifically, the Keystone and Conemaugh generating stations are scheduled to be deactivated in 2007 and 2010, respectively. These deactivation dates also are fully consistent with the depreciation schedules reflected in PP&L's retail customer rates as of January 1, 1997. PP&L St. 10-R, pp. 33-36.

The OCA and PPLICA recommend that the Commission extend the deactivation dates for both the Keystone and Conemaugh generating stations to match the dates utilized by PECO for its share of these plants in its Restructuring Plan proceeding at Docket No. R-00973953. OCA St. 1, p. 16; PPLICA St. 3, pp. 31-32. In support of his argument, Mr. Kollen asserts that these generating stations are operated by PECO, and concludes that PECO's deactivation dates therefore are correct. PPLICA St. 3, p. 31. The opposing parties' recommendation is rejected for several reasons.

First, PP&L's proposed deactivation dates are consistent with the expected operating life for this type of generating unit. Specifically, the Keystone units began service in 1967 and 1968. Based on the deactivation date approved by the Commission in PP&L's last base rate case, i.e., 2007, these units have projected service lives of 40 and 39 years, respectively. Similarly, the Conemaugh generating units began operation in 1971 and 1972. Based on the deactivation date approved by the Commission in PP&L's last base rate case, i.e., 2010, these units have an expected operating life of 39 and 38 years. PP&L St. 10-R, pp. 35-36. As Mr. Krall explained, the Company's proposed deactivation dates properly reflect the design and operating limitations for these units:

> Lives of 35 to 40 years are appropriate for 1970-vintage 800 MW-class once-through super-critical pressure generating units. This class of units "stretched the envelope" on certain mechanical designs and materials selections and have, in fact, seen certain stress-related problems occurring at 15 to 20 years of age which would normally not occur in lower temperature and pressure units until 30 to 40 years of age. The current lives assigned by PP&L,

[45] This item is not a regulatory asset.

> and approved by the Commission, reflect these issues and also are consistent with commitments made to comply with the requirements of the 1990 Clean Air Act Amendments. Any extension of these lives is speculation. PP&L St. 10-R, p. 36.

Second, the parties' reliance on PECO's proposed deactivation dates is misplaced. In fact, the various owners of Keystone and Conemaugh frequently have utilized different deactivation dates in establishing their respective rates. The Commission has reviewed and approved each of these dates.

Third, Mr. Kollen is incorrect in asserting that PECO's deactivation dates should be utilized because PECO operates the Keystone and Conemaugh units. The record evidence demonstrates that these generating units are operated by GPU subject to oversight by the Keystone-Conemaugh Projects Office. PECO, like PP&L, is a joint owner, and no owner may unilaterally cause investments at these stations that would extend their lives. Such investment decisions require approval by 75% of all ownership shares. Because the Commission lacks jurisdiction over five of the owning companies whose ownership shares exceed 25%, the Commission is unable to require investments to extend the lives of these stations. PP&L St. 10-R, p. 37.

In sum, PP&L's proposed deactivation dates are appropriate and should be approved. The proposed dates are identical to the dates approved by the Commission in the Company's last base rate case, and are fully consistent with the expected operating lives of the facilities.

11. Rate Case Expenses

The Company included in its calculation of stranded costs the present value of the generation-related portion the total annual recovery of rate case expenses that would occur through existing rates. The Commission authorized PP&L to recover rate case expenses associated with its base rate proceeding at Docket No. R-0094371 over a four-year period. PP&L St. 8, p. 26.

Raising the same argument used in opposition to PP&L's claim for deferred SSES refueling expenses, the OTS and OCA recommend that the Commission disallow the Company's claim. Like SESS Deferred Refueling Costs, PP&L is attempting to claim its 1994 Rate Case Expense as a stranded regulatory asset. The Company's claim for Rate Case Expense represents the cost incurred relative to generation as a result of the Company's most recent base rate case. OTS St. 2 at 13. Like SESS Deferred Refueling Costs, OTS disagrees with PP&L's recovery of 1994 Rate Case Expense as stranded regulatory assets. The reasons for OTS' recommendation are in many aspects similar to the reasons set forth above regarding SSES Deferred Refueling Costs

In rebuttal, PP&L witness Schadt defended the Company's claim for Rate Case expense as a stranded regulatory asset, based on the Company's belief that for accounting purposes, PP&L properly established a regulatory asset in accordance with SFAS 71 . Furthermore, it is this regulatory asset which the Company is recognizing as a stranded cost in this proceeding. PP&L St. 8-R at 39. OTS argues and we agree that while Mr. Schadt's arguments may be proper for accounting purposes, they are not proper for ratemaking purposes, where certain expenses are normalized. From a ratemaking viewpoint, PP&L is only entitled to include in rates an amount that represents what would normally be incurred in a year for litigating a base rate case. OTS St. SR-2 at 6. As previously discussed, contrary to Mr. Schadt's argument, for ratemaking purposes, the total rate case expenses has no significance beyond the determination of a normal year's expense. Id., at 6. Simply put, as Mr. Reed explained, PP&L is not entitled to recovery of its unamortized rate case expense in this proceeding than it would be in a base rate proceeding in a regulated environment. Id., at 6.

The Act, at 66 Pa. C.S. Section 2803, defines stranded costs in pertinent part as that "which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market." Consequently, there is no basis for the Company's position to recover its 1994 Rate Case Expense as stranded regulatory assets. Since the manner in which PP&L is seeking to recover these costs, the same costs could not be recovered in that manner in a regulated environment. The effect of Mr. Reed's disallowance of the rate case expense and the deferred fuel results in reduction of $8,527,000 to the Company's net present value relative to regulatory assets.

Specifically, Messrs. Reed and Catlin argue that the Commission previously approved normalization of PP&L's rate case expenses, not deferral and amortization of such costs. OTS St. 2, pp. 13-16; OCA St. 3, p. 12. Disallowance of the unamortized expenses would reduce the nominal balance of the Company's regulatory assets by $184,000. OCA St. 3, p. 12. The parties' recommendation is well taken.

12. Safe Harbor

On rebuttal, the Company corrected an error in its original stranded cost calculation related to the Safe Harbor facility. Specifically, PP&L's initial calculation did not include the energy revenues and the operating and maintenance expenses associated with this facility. The revenues related to Safe Harbor's capacity inadvertently were included with the Holtwood Dam hydroelectric project's revenues for capacity. The effect of properly including the remaining revenues for energy from Safe Harbor and all of its operating and maintenance costs increases PP&L's stranded costs by $38 million. PP&L St. 8-R, pp. 55-56. These corrections are shown in PP&L Exhibit JRS 8.

13. Other Regulatory Assets

PP&L notes that it has not presented a claim for stranded costs associated with its Pilot Retail Competition Program because the amounts are not known. PP&L reserves the right to claim these costs in its Compliance Filing or other appropriate point in the process. See Opinion and Order on Pilot Program Initiatives, Docket No. P-00971183, p. 26. Also, PP&L has proposed to offset this pilot program regulatory asset with a regulatory liability reflecting the refund to customers arising out of the Commonwealth Court's decision in *Popowsky v. Pa. P.U.C.*, 695 A.2d 448 (Pa. Comwlth. 1997), dealing with gross receipts tax on uncollectible accounts.

VI. DETERMINATION OF PRESENT VALUE

A. Appropriate Discount Rate

As explained in Section III, above, PP&L used the regulatory method to calculate its stranded costs. Under this method, the Company compared the revenue stream it could have received under traditional cost-of-service regulation with the stream of revenue it could receive in a competitive market. PP&L discounted the difference between these two amounts to January 1, 1999 using a discount rate of 7.92%, which is PP&L's after-tax weighted average cost of capital ("WACC"). PP&L St. 8-R, p. 5; PP&L Exh. JRS 1, p. 1. The OTS, OCA and OSBA oppose both the Company's proposed discount rate and the application of such rate. As explained in PP&L's M.B. at pp. 131-134, each of the arguments raised by the parties is without merit and we reject them.

We adopt PP&L's discount rate of 7.92 percent.

B. Application of Discount Rate

1. Income Taxes

The OCA asserts that PP&L improperly applied an after-tax discount rate to calculate the present value of pre-tax revenue requirements and market prices. OCA St. 1, p. 13. As a result, the OCA claims that the Company overstates its stranded costs by $880 million.

As explained by Mr. Guth, stranded costs are analogous to economic damages because they represent a decrease in value caused by some act or event, in this case, the transition from regulated rates to market-based rates. PP&L St. 19-R, p. 20. As such, taxable stranded costs properly should be measured utilizing pre-tax cash flows and after-tax discount rates:

> In computing economic damages, we want to compensate the owner of damaged assets just enough to restore her to her prior position. Since future cash flows -- as well as the subsequent return earned on those cash flows -- are taxable, we must discount to present value taking into account tax effects by using an after-tax discount rate. But, since damage awards are ordinarily taxable, we must adjust the cash flows to pre-tax levels so that the owner is made whole after taxes on damages are paid. PP&L St. 19-R, p. 21.

Although Mr. La Capra and Mr. Falkenberg utilize an after-tax discount rate to calculate stranded costs, they err by computing PP&L's stranded costs based on *after-tax* revenue requirements and market prices. Specifically, these witnesses reflect income taxes in calculating the value of PP&L's generating assets, but fail to adjust stranded costs upward to account for the taxability of CTC revenues. PP&L St. 19-R, p. 21. As Mr. Guth explained, Messrs. La Capra and Falkenberg:

> computed what they assert is the market value of PP&L's generating assets after taking into account income taxes. That procedure is all right, so long as measured stranded costs are then adjusted upward to take into account the taxability of CTC revenues that are based on stranded costs. Thus there really are

two alternatives where the present value amount of future cash flows is taxable income:

1. use pre-tax cash flows, and after-tax discount rates to compute the present value of taxable income; or
2. use after-tax cash flows, and after-tax discount rates to compute the present value of after-tax income, then gross up the result for tax coverage. PP&L St. 19-R, pp. 21-22.

The OCA's proposal is incorrect because it fails to adopt either of these approaches and effectively disallows the recovery of income taxes. The OCA's recommendation regarding application of the discount rate therefore is rejected.

2. Discount Rate Method

PP&L discounted its revenue requirements on a monthly basis. The OCA discounted on a semi-annual basis. A monthly calculation is more accurate, is consistent with PUC, practice in calculating ECRs and was approved in the PECO Restructuring proceeding (Order on Compliance Filing, p. 6). As shown in Table D of PP&L's M.B., the OCA's method understates stranded costs by $48.374 million ($71.072 for Market Value, less $5.815 million for Regulatory Assets, less $8.982 million for NUG Contracts and $7.899 million for Nuclear Decommissioning).

VII. RECOVERY OF STRANDED COSTS

A. Design of the Competitive Transition Charge

Under Section 2808(a) of the Act, electric distribution companies will recover their stranded costs through CTCs. These charges will be applied to every customer of electric distribution companies. The rate design for PP&L's CTC is based upon principles derived from two different sources. First, the Act contains a set of principles that are to be followed in designing CTCs. Second, PP&L has followed fundamental principles of rate design that are widely accepted and applied in utility ratemaking.

Three statutory provisions influence the rate design of PP&L's CTC. First, the CTCs are constrained by the rate caps. Under Section 2804(4)(ii) of the Act, there may be no increase in the generation component of rates, which includes the CTC, for nine years from the Act's effective date, January 1, 1997, through December 31, 2005. Second, Section 2808(a) of the Act mandates that the CTC be designed "in a manner that does not shift interclass or intraclass costs and maintains consistency with the allocation methodology for utility production plant accepted by the Commission in the electric utility's most recent base rate proceeding." Third, PP&L's CTCs are designed in a manner to promote the overall purpose of the Act, which is to establish an active and viable retail market for electric generation.

In addition to these statutory considerations, PP&L has applied sound ratemaking principles in designing its CTC. PP&L has sought to provide a more efficient marginal price signal to customers. PP&L St. 9, p. 20. Further, PP&L has simplified its delivery service rate design.

PP&L used a "bottom-up" approach to design its CTC, PP&L St. 9, pp. 23-26; starting with its present rates. The first step was to determine for each rate in each rate schedule, the portion of the rate related to delivery of electric energy. The portion of revenues under each rate schedule attributable to distribution service was determined by application of allocation percentages based upon a test year ended December 30, 1995.[46] Since customer costs are not generation-related, 100% of customer charges were determined to be for delivery service. The remaining amount of delivery costs under each rate schedule is to be recovered under a uniform amount per kWh for each rate schedule. The delivery portion of each rate was then subtracted from the total rate; the remainder is the generation portion of the rate.

The next step is to subtract from the generation portion of each rate the projected retail market price of electric energy. The remainder after this subtraction is the portion of the rate under the rate cap that is available for use as the CTC.

As explained above, PP&L's total stranded costs are approximately $4.5 billion.[47] PP&L has determined that, under the rate cap, the maximum CTC revenue that can be attained over the transition period through 2005 is only $4.0 billion. PP&L St. 10-R, p. 3. Thus, due to the rate caps, PP&L's projected CTC revenues will fall $500 million short of recovering all of PP&L's stranded costs. Therefore, PP&L set its proposed CTCs at the maximum amounts available

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[46] These allocation percentages were accepted in the Commission's Order entered in PP&L's most recent base-rate case (Docket No. R-00943271, order entered on September 27, 1995, at 197).

[47] This figure includes, of course, GRT and is subject to income tax. PP&L's actual recovery of stranded cost will be less than $2.25 billion after taxes. See Table E.

under the rate cap after allowing for the projected retail market price of electric energy and the portion of each rate for delivery services.

Although the rate cap does not change throughout the transition period, the projected retail market price of electric energy increases each year of the transition period. Therefore, for each rate, there is a different energy and capacity credit and a different CTC for each year of the transition period through 2005. See, e.g., Exh. OGK 2, pp. 20-21.

PP&L's rate design for its CTC meets each of the statutory and ratemaking principles identified above. First, it successfully meets the Act's rate cap requirements. By calculating the CTC as the residual remaining after subtracting the delivery portion of the rate and the projected cost of electric generation during the transition period (which is the maximum charge for PP&L's Basic Utility Service ("BUS")) to last resort customers means that PP&L's proposed CTCs cannot exceed the rate cap.

Second, PP&L's rate design will not cause shifting of costs between rate classes or within rate classes. The generation portion and the delivery portion of PP&L's present rates were determined by application of allocation percentages from the cost of service study used to design PP&L's present rates. PP&L St. No. 3, pp. 6-7; Exh. JMK 1. Use of the cost of service allocation percentages from the electric distribution company's most recent base-rate case to unbundle rates has been approved by the Commission. PECO Order, pp. 109-10.

Third, CTCs have been designed to achieve simplicity in the delivery service rate design. The CTCs have declining block rate designs that follow PP&L's presently-effective rate design. The delivery charge includes the presently-effective customer charge and flat usage charges per kWh.[48] Therefore, when the CTC is eliminated at the end of the transition period, the remaining charges of PP&L under PP&L's rate schedules for most customers will be a customer charge combined with a flat energy charge for usage. Customers can understand this pricing structure and will be able to work with it to obtain electric energy under the most favorable terms and conditions. PP&L St. 9, p. 21 .

OCA and OSBA recommend, based on an assumption that PP&L will be allowed to recover a much lower level of stranded costs than it has proposed, that recovery of stranded costs be spread over the full transition period even if a substantial portion of stranded costs are

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48 There will also be demand charges for rate schedules presently containing demand charges.

disallowed. OCA St. 4, pp. 9-14; OSBA St. 1, p. 12. These recommendations should be rejected. Such an unnecessary delay in recovery of stranded costs would impose on PP&L an increased risk that it will be unable to recover all of its allowed stranded costs if market conditions change in the future. Moreover, the CTC should be set at the maximum level consistent with the rate cap until the allowed level of stranded costs is recovered because this approach will eliminate the distortions in electric energy market prices caused by the CTCs at the earliest possible date. PP&L St. 9-R, pp. 22-25.

Various parties in this proceeding have proposed alternative methods for PP&L to recover its stranded costs. The proposals by other parties consist of "levelizing" or otherwise unnecessarily spreading recovery of stranded costs over time. For a summary of various alternatives, see, e.g., OCA St. 4-S, pp. 2-3, OCA Exh. LS-10. These proposals should be rejected. First, they are based on the assumption that a substantial portion of PP&L's stranded costs will be disallowed by the Commission. For the reasons explained previously such assumption is unfounded. Second, levelizing recovery of stranded costs has the effect of shifting that recovery from the early years of the transition period to the later years. The result is a significantly adverse impact on PP&L's financial indicators in those early years, compounding the financial impact of any disallowance of stranded cost recovery.

B. Prohibition on Inter and Intra Class Cost Shifting

Certain intervenors contend that PP&L's methodology for establishing its CTCs is inappropriate. Specifically, AARP contends that costs should be reallocated so that a larger share of CTC revenues is derived from non-residential customers. AARP St. 1, pp. 28-29. The Environmentalists contend that the Commission should take a fresh view of allocating stranded costs among the rate classes. Environmentalist St. 1, p. 26. These proposals should be rejected because they directly contravene the mandates of Section 2808(a) of the Act, which requires that the CTC be established in a manner that does not shift cost recovery either between classes of customers or within a customer class, and in a manner that maintains consistency with the allocation methodology accepted by the Commission in the utility's most recent base rate case.

C. CTC Reconciliation and Tracking

Section 2808(f) of the Act provides that annual CTC revenues shall be reconciled with the amortization of stranded costs authorized by the Commission for the same period. PP&L proposes to implement this statutory mandate by following procedures, subject to one exception, similar to the annual Energy Cost Rate ("ECR") reconciliation procedures that had been in place in Pennsylvania for many years prior to passage of the Act. PP&L St. 3, p. 17. PP&L proposes to track, on a system basis, its annual CTC revenues and compare those revenues with the annual amortization authorized by the Commission. PP&L would submit quarterly filings to the Commission reporting the results of the tracking process. However, in a departure from ECR practice, PP&L would not change its CTC annually to reflect overcollections or undercollections.

PP&L argues that because its rates will be set at the rate caps throughout the transition period, PP&L would be precluded by the rate caps from recouping from customers any prior period undercollection. Accordingly, PP&L is proposing that the CTC application period be extended or contracted to permit a net reconciliation of overcollections or undercollections. That is, if CTC revenues were more than the amount authorized by the PUC, the CTC would be terminated at the appropriate time prior to December 31, 2005. Conversely, if CTC revenues were less than the amount authorized by the PUC, the CTC period would be extended beyond December 31, 2005.

Section 2808(b) of the Act permits the Commission, "for good cause shown," to order an alternative CTC payment period which may be longer or shorter than the nine-year period. PP&L states that it has shown good cause why the period for application of the CTC should be extended if CTC revenues during the period ending December 31, 2005, fall short of the level of stranded costs that PP&L is authorized by the Commission to recover from customers. PP&L St. 3, pp. 18-19.

PP&L's asserts that its proposal to adjust the CTC application period for reconciliation of stranded costs also protects the interests of customers. First, if the Commission approves PP&L's proposal to extend the period for recovery of stranded costs beyond December 31, 2005, PP&L voluntarily will extend the generation-related rate cap to coincide with the extension of the period for application of the CTC. PP&L St. 3-R, p. 26. Second, the CTC will be known and predictable throughout the transition period enhancing the ability of customers to compare offerings by alternative electric energy suppliers and calculate potential savings. Third, PP&L has kept the CTC mechanism as simple as possible by not reflecting any calculations of interest on overcollections or undercollections of the annual CTC amortization in the reconciliation process. PP&L St. 3-R, p. 25.

In the PECO case, the Commission rejected a similar CTC reconciliation proposal, concluding that Section 1307(e) of the Code, 66 Pa.C.S. § 1307(e), requires a dollar adjustment over an appropriate 12-month period. PECO, p. 113. However, Section 1307(e) begins with the phase "[a]bsent good reason being shown to the contrary," which grants broad discretion to the Commission in this area. In its PECO order, the Commission appears to conclude that this discretion can be exercised only after hearings on the reconciliation adjustments. *Id.* Unlike PECO, however, PP&L has not proposed extending the CTC application period to recover allowed stranded costs, rather the only extension proposed would be for the collection of reconciliation amounts. PP&L argues that the Commission should be able to exercise its discretion at any time; the hearing requirement only limits the time when it can enter a reconciliation order. PP&L submits that it has provided good reason for modifying the requirements of Section 1307(e) and that the Commission should approve its proposed CTC reconciliation mechanism.

Certain parties contend that PP&L should not be permitted to extend the period for application of the CTC to customers' bills unless PP&L applies to the Commission for specific permission for such an extension near the end of the transition period. PPLICA St. 1, p. 6; OSBA St. 1, p. 36. Apparently, such an application would allow the Commission to determine in a future proceeding whether stranded costs in fact had turned out to be equal to or less than the amount projected in this proceeding or whether further recovery should be denied for any number of unspecified reasons. PP&L contendes that although other parties' testimony on this subject is vague, their proposals suggest an unfair, one-sided review in which stranded cost recovery could only be decreased, even if stranded costs turned out to be greater than the level authorized by the Commission.

PP&L asserts that under Section 2808(f) of the Act, the reconciliation process consists solely of comparing CTC revenues with levels of stranded costs authorized by the Commission to be recovered. No provision of the Act indicates that the reconciliation process should provide an opportunity for all parties to relitigate the stranded costs issues being decided in this proceeding. Moreover, such relitigation for reconciliation purposes would impose unnecessary administrative burdens on the Commission and all parties.

PP&L argues that for these reasons, other parties' proposals that an extension of the CTC application period beyond December 31, 2005, be made conditional upon future Commission approval should be rejected. We disagree.

OCA has recommended that the CTC be reconciled by rate class. OCA St. 4, pp. 17-18.[49] This proposal should be rejected for several reasons. First, there is no support for the proposal in the Act. Section 2808(f) is silent on the subject. Second, and of greater importance, OCA's proposal would not solve the perceived problem that it is intended to address. Instead, it would create additional problems. Under OCA's proposed reconciliation by rate class, this "problem" will remain unresolved for customers within a rate class. Inevitably, customers using more energy in the transition period will pay more stranded costs than they would pay under allocations based on historical usage.

OCA's proposal for CTC reconciliation by rate class is rejected.

D. CTC and Rate Cap Extension

For the purpose of this proceeding, the Competitive Transition Charge

("CTC") For the purpose of this proceeding, the Competitive Transition Charge

(CTC)

is defined in 66 Pa. C.S. Section 2808 as follows: is defined in 66 Pa. C.S. Section 2808 as follows:

> "A nonbypassable charge applied to the bill of every customer accessing the transmission or distribution network which (charge) is designed to recover an electric utility's transition or stranded costs as determined by the Commission under Section 2804 (relating to standards) and 2808 (relating to competitive transition charge)."

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[49] It is noted that the Commission required PECO to reconcile CTC revenues and costs by class. PECO Order, p. 112. In that Order, however, the Commission did not address PP&L's explanations, provided above, that class reconciliation is not required by the Act or customers' interests. Therefore, this issues should be given fresh consideration by the Commission in this proceeding.

Consequently, the amount recovered as a CTC is subject to an annual reconciliation. The reconciliation occurs after the Commission has determined the appropriate amount of stranded costs and the total Kwh sales over which it is to be recovered. The electric utilities will reconcile the actual annual Kwh sales to Kwh sales projected in the final order. OTS St. 2 at 8. Any over/underrecovery of stranded costs based on a variation in annual sales will be reflected as an adjustment to the subsequent years CTC. Id., at 9.

In the instant proceeding, PP&L's filing does not include an annual adjustment to its CTC. As explained by OTS witness Reed, it is the position of PP&L that the rate cap imposed by the Act prohibits the Company from fully recovering its full level of stranded costs. OTS St 2 at 9. Consequently, any annual reconciliation that resulted in an increase to the CTC would be prohibited by the rate cap. Id., at 9. As an alternative to reconciliation, the Company has proposed to track the annual collections pursuant to the CTC and compare them to the level authorized by the Commission, however, the actual CTC will not be adjusted to reflect any resulting differences. PP&L St. 3 at 17-19. Additionally, PP&L is proposing that near the end of the stranded cost recovery period, the CTC would be adjusted to reflect the net amount of over/undercollections that occurred throughout the stranded cost recovery period. Id., at 9. Based upon PP&L's alternative proposal, depending on whether the amount is net over or underrecovery, the CTC will either be terminated early or extended beyond the maximum nine years specified in the Act. OTS St. 2 at 9-10.

OTS submits that PP&L's alternative to the reconciliation provision of the Act is inappropriate. First of all, PP&L's alternative is premised on the "unlikely" fact that the Commission will allow the Company to recover the full requested amount of its stranded costs. Consequently, if the Commission disallows a portion of PP&L's stranded costs, PP&L's CTC will be below the cap, which will allow PP&L to make annual adjustments to its CTC. OTS St. 2 at 10. Moreover, Section 2808 of the Act requires annual reconciliation of CTC revenues in order to ensure that CTC revenues are no less than, nor greater than, the authorized amount.

In the event that PP&L's CTC allowance does not permit an upward adjustment on an annual basis, OTS is recommending that the CTC should be tracked and the CTC be extended beyond nine years, if necessary. Id., at 10. The difference between the recommendations of OTS and PP&L is that OTS is recommending that any reconciliation of CTC overrecovery revenues that does not violate the rate cap imposed by the Act be made in the subsequent recovery year. Id., at 10. OTS is concerned that under the Company's proposal, a miscalculation or change in Kwh demand could result in overrecovered revenues that would be denied the customers/ratepayers without the benefit of receiving any accrued interest on the overrecovery. Id., at 10. An additional benefit of OTS' recommendation is that recognizing overrecoveries when they occur will provide rate cap relief so that the CTC can be adjusted to recoup any future underrecoveries.

Accordingly, the recommendation of OTS should be adopted by the Commission as being in the public interest.

E. Return on Unamortized CTC Balances

Pursuant to the Act, electric generation-related stranded costs are to be "determined on a net present value basis over the life of the asset or liability as part of its restructuring plan . . . ." See Section 2803, definition of "transition or stranded costs." In Section VI of the PP&L M.B. Brief, PP&L explained the proper rate for discounting the value of future stranded costs to January 1, 1999.

Similarly, a proper net present value determination also must recognize that PP&L's stranded costs will be recovered over a seven-year period ending December 31, 2005. For the reasons that stranded costs are discounted to net present value, PP&L's recovery of stranded costs must reflect an appropriate return on uncollected CTC balances.

In the PECO Order, the Commission set the applicable rate of return on unamortized CTC balances at PECO's long term debt cost rate. PECO Order, p. 108; *see also* PP&L St. 19-R, pp. 28-29. PP&L's long-term debt cost is 7.89%. PP&L Exh. JRS 1, Tab A, Attach. 1.

Regardless of the cost rate, however, a substantial portion of PP&L's assets, including stranded assets, are financed with securities on which PP&L pays dividends that are subject to income taxes. For this reason, the portions of the amount to be inflated must be "grossed up" for income taxes. Exhibit JRS 1, Tab A, Attachment 1, provides PP&L's capital structure and cost rates. Exhibit JRS 1, Tab A, p. 4, provides its composite income tax rate of 41.4935%. Using these data, that have not been controversial in this proceeding, produces the appropriate rate to be applied to amounts to be recovered through the CTC over seven years. See Table F PP&L M.B.

Thus, the appropriate overall, pretax rate of return allowed on PP&L's unamortized CTC revenues, during the seven-year period, is 10.86% using PP&L's average long-term debt cost as the return to all classes of PP&L securities. If PP&L's actual cost of capital were used, the figure would be 13.54%. PP&L M.B. Table F.

Failure to allow any return on unamortized CTC balances, as suggested by several parties, would amount to an unlawful taking of PP&L property without just compensation. Unamortized CTC balances represent the very same costs upon which the Commission was required to allow a reasonable return. See 66 Pa.C.S. § 1301; *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 315 (1989). Converting the manner in which those costs are recovered from traditional rates to a CTC charge does nothing to change PP&L entitlement to a reasonable return on its investment.

VIII. RATE DESIGN AND TARIFFS

A. Customized Rate Design

As an alternative to collecting its CTC on a strict usage (kWh) basis, PP&L has also proposed what it refers to as a customized rate design (CRD). According to this design, one half of a customer's CTC will be recovered through usage-based charges, while the remainder will be recovered through a fixed customer charge. PP&L M.B., p. 147. PP&L describes the calculation of the CRD as follows:

> The CRD will be calculated individually for each customer. First, each customer's usage during 1996 will be priced at rates established in this proceeding using a CTC calculated under traditional, usage based rates. This amount will then be divided by 12 to determine a monthly amount. One half of the monthly amount will be added to the customer charge. The remainder will be priced on the basis of 1996 energy usage so that the annual cost

> of electric service will be unchanged from the annual cost for 1996. PP&L St. 10, pp. 11-12; PP&L St. 9, p, 33; PP&L Exh. DAK 1.

PP&L M.B, pp. 148-149.

PP&L states that the CRD will result in rate reductions for customers with incremental usage over 1996 levels:

> The effect of the CRD, in comparison with a more traditional usage-based (cents-per-kWh) charge are several. First, if each customer were to use during any year of the transition period, the same amount of electric energy as it used during 1996, the customer would pay the same total amount of CTC under both the CRD and the traditional, usage-based rate design. If, however, a customer were to use more electric energy per year during the transition period than in 1996, the customer would pay less under the CRD than under the traditional rate design. Conversely, if a customer were to use less electricity during the transition period than in 1996, the customer would pay more under the CRD than under the traditional rate design.

PP&L M.B, pp. 148-149.

PP&L asserts that the CRD will stimulate growth in the Pennsylvania economy by providing rate reductions for incremental usage, and will effect a movement toward marginal cost pricing. Id., pp. 148-149.

PP&L originally proposed that the CRD method of recovering CTC revenues be optional for residential customers, but mandatory for non-residential customers served on major rate schedules. However, PP&L now proposes that the CRD be optional for all customer classes. Id., p. 148.

A number of parties have opposed PP&L's proposed CRD. The OCA argues that it is inefficient because the marginal cost of transmission and distribution is higher than the embedded revenue requirement. Thus, a flat transmission and distribution charge and a fixed CTC may not send the proper price signals to customers with regard to marginal usage. OCA M.B., pp. 83-85. The OCA also contends that the CRD is a promotional rate design which inappropriately encourages energy use by shifting CTC responsibility from customers who increase usage to customers who conserve energy. Id., p. 85-86.

PPLICA argues that the CRD violates the rate cap and cost shifting prohibitions contained in Chapter 28, and amounts to a take-or-pay charge for 50% of PP&L's recoverable stranded costs. Large Customers M.B., pp. 77-80. However, PPLICA is willing to accept the proposed CRD if it is to be optional to all customer classes. Large Customers M.B., p. 80; R.B., p. 48.

The Public Interest Parties and PPA/PAPHCC also object to the proposed CRD for reasons similar to those of the OCA and PPLICA. Public Interest Parties M.B., p. 45; PPA/PAPHCC M.B., 8-9. The OSBA opposes the CRD as being detrimental to small business customers, but is willing to accept it if it is optional for all classes. OSBA M.B., pp. 35-37.

PP&L's proposed CRD appears to be an attempt by the Company to shield itself from some of the uncertainty involved in having the recovery of the CTC totally dependent on customer usage, which cannot be predicted with 100% accuracy. We find this rate design to be questionable for the reasons set forth by the OCA. Therefore, we recommend that it be rejected, and that the Company be required to design its CTC according to its original $/kWh format.

B. Small Business Customer Rates

The OSBA raised concerns regarding two aspects of PP&L's rate unbundling proposal which it believes will adversely affect small business customers. The first of these relates to the demand charge in Rate Schedule GS-1. As the OSBA explains:

> When PP&L backed out the transmission and distribution costs for the GS classes, it opted to assign customer charge and unblocked energy charge revenues to the transmission/distribution costs, which left a blocked energy charge and a demand charge. Further, in backing out the market price, PP&L deducted market energy rates from the residual energy charges and deducted market capacity charges from the demand charge, which left a blocked energy structure and demand charge for the CTC tariff. OSBA Stmt. No. 1 at 44.

OSBA M.B., pp. 37-38.

The OSBA asserts that since the demand charge under this rate schedule only applies to billing demand above 5 kW, customers with billing demands less than this amount will see no reduction in their transmission/distribution service bill relating to the market rate demand credit because they pay no demand charge. Also, the OSBA argues that smaller GS-1 customers will face rates that are below PP&L's forecast market rates. Id., p. 38. To resolve this problem, the OSBA proposes that the existing demand charge remain in the component of the rates designated for transmission and distribution, and that market demand charge revenues be backed out of the first and possibly second block energy rates. Id.

PP&L, through its witness Mr. Kasper, indicated that the OSBA proposal would adequately recover delivery service revenue requirements approved in the Company's last base rate case. Thus, PP&L is willing to accept this proposal. Tr. 1051-1052; 1099. We therefore recommend that it be approved.

The second of the OSBA's concerns relates to PP&L's proposal to recover all transmission and distribution costs through a flat energy charge and a fixed customer charge in Rate Schedules GS-1 and GS-3. The OSBA contends that PP&L's elimination of the declining block rate design for the recovery of these cost components may result in larger customers with higher load factors subsidizing very small customers because small customers will provide less in revenue than their allocated costs. The OSBA recommends that PP&L's current declining block rate design be maintained for these rate schedules until further examination of this issue can be conducted in a future rate proceeding. Id., pp. 38-39.

As PP&L notes, the elimination of the declining block structure from its delivery service rates results in a highly simplified rate structure. The declining block structure remains only in the design of the CTC, which is a temporary rate that will disappear at the end of the transition period. PP&L M.B., p. 137; PP&L St. No. 11-R, p. 12. With respect to the OSBA's concerns regarding large customers subsidizing small ones, these concerns appear to be unfounded since, theoretically, all customers would be supplying the same amount of revenues under the proposed rate structure as they would under the current one. The only difference is that the declining block structure under the proposed rate design will be confined solely to the CTC component of the unbundled rates. Tr. 1102. We find no evidence to suggest that delivery charges are such a significant component of the current blocked rate structure for the GS-1 and GS-3 rates that the shifting of this structure from delivery service rates to the CTC will have the detrimental affect which the OSBA alleges. For these reasons, I find it inappropriate to discard the Company's simplified rate design in favor of the OSBA's proposal, and We therefore recommend the OSBA's proposal be rejected.

C. Provider of Last Resort Service

A number of parties in this proceeding debate the issue of the proper generation rate for PP&L to charge its provider of last resort (PLR) customers--those customers who either are unable to find an alternative supplier to serve them, return to PP&L after choosing an alternative supplier, or simply choose to remain with PP&L as their energy supplier. PP&L proposes to serve its PLR customers under its Basic Utility Supply Service (BUSS), which would consist of a generation charge, a delivery charge, and the CTC as discussed above. The generation charge would be the projected market price of energy. After the completion of the phase-in period, PP&L intends to recover the cost of providing generation service to its PLR customers through a mechanism called the Purchased Generation Cost Rate (PGCR). The PGCR, which would apply to customers without hourly meters,[50] is explained by the Company as follows:

> . . . [The PGCR] would be patterned after the ECR; would be established on an annual basis; would be collected on a KWH basis; and would be reconciled for overcollections and undercollections. PP&L St. 3-R, pp. 39-41; PP&L Exh. JMK 7. The PGCR would include the market price of electricity purchased for last resort service customers and the costs of administering the Company's electricity procurement program. PP&L's proposal is fully consistent with Section 2807 (e)(3), which provides that the provider of last resort service shall acquire energy at "prevailing market prices" and recover "all reasonable costs."
>
> The PGCR would not become effective until the end of the phase-in period. Unil [sic] that time, PP&L would continue to charge non-shopping customers its Commission-approved, tariffed rates. This approach is consistent with the Commission's orders in the PECO case. PECO Order, pp. 132-134; Order on Reconsideration, pp. 20-21.

PP&L M.B., pp. 158-159.

The OCA opines that the generation rates charged to PLR customers should not exceed prevailing market rates, including all reasonable costs. In this regard, the OCA submits that

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[50] PP&L witness Kleha stated that the Company has not yet developed a proposal for recovering generation service costs from customers with hourly meters, but is continuing to study the issues involved and will submit a proposed mechanism as soon as it has been developed. PP&L St. No. 3-R, p. 39.

PP&L's market price should be adjusted to account for line losses, differences in class load shapes, and differences between residential and average retail market prices. OCA M.B., p. 80. In addition, the OCA contends that this market price must be further adjusted to include "certain administrative and general costs that will be required to market, aggregate load, reconcile load and supply, deal with PJM, write contracts, etc." Id., p. 78. With these adjustments, the OCA appears to support the use of PP&L's proposed market price as the generation component of the Company's BUSS rates for PLR customers.

It is the OCA's position that whatever difference exists between the rate cap and the sum of the unbundled rate elements (delivery charge, adjusted market price, CTC) should represent a rate reduction for the Company's PLR customers. The OCA argues that under this proposal, "all customers will receive rate savings, and alternate suppliers will have to compete based upon their ability to provide favorably priced electric generation when compared to the market-based retail generation price reflected in the Company's rates." Id., p. 81. The OCA believes that PLR customers should have the same opportunity to receive electric energy at market-based prices as those customers who choose to shop for and receive energy from alternative suppliers. Id., pp. 81-83.

The Competitive Intervenors object to PP&L's proposals with regard to the generation rates for PLR customers. They note that these rates as proposed by the Company will basically be wholesale prices which will be passed through to customers without a markup. Competitive Intervenors M.B., p. 17. They contend that PP&L's proposals are not consistent with Section 2807(e) of the Act. The Competitive Intervenors explain their position in this regard as follows:

> PP&L's proposed scheme in its restructuring plan is completely inconsistent with the Commission's stated interpretation of Section 2807(e) and is noncompliant with the Act for a whole array of reasons. First, PP&L is improperly attempting to implement Section 2807(e)(3) through this restructuring proceeding. Subsection (e)(2) expressly mandates that the provisions of Subsection (e)(3) pertaining to the connection, delivery and acquisition of electricity for default customers be implemented through the promulgation of regulations. No other authority is provided to the Commission as to implementation of this portion of the statute. Furthermore, Subsection (e)(2) dictates that the mandatory rulemaking to implement Subsection (e)(3) establish the ECD's "obligations that will exist at the end of the phase-in period" as ordered by the Commission in this proceeding.

> Subsection (e)(3) sets the standard governing the Commission's promulgation of regulations and states that, under the regulations, the PLR is required to "acquire electric energy at prevailing market prices to that customer and shall recover fully all reasonable costs." Read together, the two subsections require the Commission to promulgate rules following restructuring which define the EDC's obligation to serve including the terms and conditions under which it will acquire and sell power to default customers. Until such regulations are finalized, the EDC must charge default customers current unbundled tariff rates unless the Commission finds that rate reductions are warranted under Chapter 13 procedures.

Id., pp. 19-20, footnotes omitted.

The Competitive Intervenors also assert that Section 2807(e)(3) requires an EDC to acquire, not sell, energy at prevailing market prices, and requires full recovery of all reasonable costs. They state that "[p]resently, EDCs recover all reasonable costs associated with providing generation supply to customers through regulated rates and should continue to do so in the rates they charge default customers until such time as the Commission finds justification for reducing those rates through ratemaking activity or until the Commission promulgates regulations which establish an alternative methodology for computing market based rates for default customers." Id., p. 20. The Competitive Intervenors further contend that "[e]ven if the Commission could implement a market based pricing scheme without a rulemaking, PP&L has not met its burden of demonstrating that its proposed default prices for 1999 and 2000 recover all reasonable costs." Id.

In addition to the Competitive Intervenors' position as set forth in its briefs, MAPSA, a member of the Competitive Intervenors, also contends in its own supplemental brief that PP&L's wholesale market price projections are too low to foster competition. MAPSA Sup. B., pp. 2-3. MAPSA asserts that PP&L's generation rates should be based on the long run cost of energy added to the long run cost of capacity, plus a credit for the additional services which suppliers are required to provide. Id., pp. 4, 9.

Finally, SER/Gilberton provide arguments similar to The Competitive Intervenors and MAPSA. SER/Gilberton M.B., pp. 6-11. They contend that, "[s]hould PP&L fail to add to the wholesale acquisition cost of each unit of electricity all expenses reasonably incurred in performing the supplier-of-last-resort service (including, for example, a 'buying group' service charge or commission), it would be guilty of predatory pricing that would impede fair competition." Id. p. 10. SER/Gilberton conclude as follows:

> To avoid the anomaly of rewarding the least adventurous consumers (i.e., those for whom PP&L is the default service provider) with arguably the lowest priced electricity available in the marketplace, the commission should require that at no time may the BUSS energy price be set *below* the standard offer price for the same class of service marketed by PP&L's unregulated Generation Supply Group. This will ensure that the BUSS rate is a representative surrogate for retail energy prices set by free market forces rather than an unfairly subsidized artifact of cost of service rate making. In the alternative, the commission should specifically define which operating costs (in addition to direct bulk energy acquisition cost) must be factored into the BUSS energy price to achieve parity with prices set through competition. This would allow the legitimacy of the rate to be confirmed by audit.

Id., p. 11.

We agree with the OCA that in a competitive market, PLR customers should be afforded the same opportunity to receive market-based generation rates as those customers who choose to go elsewhere for their electric energy. However, we also agree generally with all the parties who contend that the Company's generation rates for these customers should not be priced so low as to undercut the market and thwart competition in the first place. Such rates should be genuine market-based retail rates that include all reasonable costs incurred to obtain the energy. Therefore, we recommend that during the phase-in period, PP&L's generation rates for its PLR customers be based on its projected market price of generation as adjusted in the manner set forth by OCA. However, we also recommend adoption of the SER/Gilberton position that these rates should at no time be set below the standard offer price for the same class of service marketed by PP&L's unregulated Generation Supply Group. In this way, the development of reasonably competitive generation rates for PLR customers should be ensured.

With regard to the proper generation rates to be charged after the phase-in period, it appears that the Company must await the promulgation of regulations by the Commission, as required under Section 2807(e)(2) of the Act, before the provisions of Section 2807(e)(3) can be fully implemented. Thus, we find PP&L's proposed PGCR mechanism to be premature, and we recommend that it be rejected at this time.

D. Availability of Tariff Rates

PPLICA objects to PP&L proposals to make its interruptible and price response rate schedules, as well as Rate Schedules RTD and RTS, available only to those customers who currently take service under these schedules and elect to remain bundled sales customers of PP&L. SER/Gilberton objects to these proposals as well. Both of these parties object mainly to the fact that under these proposals, customers of the affected rate schedules who choose to buy energy from a competitive provider would be charged a CTC based on the firm rate schedule applicable to their level of load, rather than on their current rate schedule. Large Customers M.B., pp. 71-77, SER/Gilberton M.B., pp. 3-4.

PPLICA asserts that an interruptible customer's CTC liability is based on embedded stranded costs, and is naturally smaller than that of a firm customer. PPLICA argues that such liability for an interruptible customer should not change simply because that customer chooses to access the competitive market. Large Customers M.B., pp. 72-74. PPLICA contends that PP&L's proposals are in violation of the cost shifting prohibitions of Chapter 28 because they cause interruptible customers who exercise their right of access to pay higher rates. Also, PPLICA asserts that they will result in the collection of greater CTC revenues from interruptible customers than would otherwise occur, leading to an earlier termination of the CTC which would, in turn, result in all other customers on the PP&L system paying a lower CTC than they otherwise would. Id., p. 74. PPLICA also contends that PP&L's proposals with regard to the rate schedules in question violate the pro-competition and pro-business growth goals of Chapter 28 of the Act by producing higher prices for electric service, and restricting access to the competitive market for those customers affected. Id., pp. 75-77, 82-83.

In response, PP&L argues that the benefits of interruptible service provided to the Company and its customers are related totally to generation service. PP&L asserts that there is never a need for interruptions of delivery service on its system because the Company never experiences any local transmission or distribution emergencies that would require such interruptions. Therefore, PP&L concludes that customers who purchase energy from a competitive provider and receive only delivery service from PP&L should not receive the discounts offered under interruptible service rates, but should be served under rate schedules for firm service. PP&L M.B., pp. 144-146; R.B., p. 56-58. PP&L makes a similar argument with regard to its Residential Thermal Storage (RTS) rates. PP&L R.B., p. 59.

We find PP&L's arguments to be persuasive with regard to this issue. Interruptible service customers who choose to purchase energy from competitive providers will no longer provide the benefits to the Company and its remaining ratepayers that they did as fully bundled service customers of PP&L. For all practical purposes they will no longer be interruptible service customers since they will no longer face the prospect of being interrupted by PP&L for generation related emergencies. This applies also to customers of other rate schedules who, in changing generation service providers, would no longer supply the benefits to the Company that they would as full service customers. Under circumstances such as these, we do not find that the shifting of customers from one rate schedule to another violates the rate cap since no tariffed rates are actually being changed. Customers who wish to enjoy the benefits of a competitive market for electric energy must be willing to forfeit some of the benefits they received as bundled service customers of a monopoly provider, when such benefits are no longer applicable. For these reasons, we recommend that PP&L's proposals with regard to these rate schedules be approved, and that the positions of the opposing parties be rejected.

E. Economic Incentive Rates

PP&L offers a number of incentive rates in the form of riders, rate schedules and billing options which are designed to promote economic growth and/or improve the Company's load factor. PP&L M.B., p. 150. Although many of these incentive rates are scheduled to terminate in the relatively near future, PP&L is proposing to extend their availability through the end of the CTC application period so as not to violate the rate cap required by Section 2804(4) of the Act. However, PP&L is proposing to limit the availability of incentive rates to customers presently being served under them, and using PP&L's BUSS service for their energy supplies. Also, customers who temporarily use alternative competitive energy suppliers and return to PP&L's BUSS service will not be eligible to receive service under the incentive rates.[51] According to PP&L, the reason for these proposals is that the incentive rates were designed to benefit the

[51] PP&L notes that there is one exception to the requirement to use BUS service. Unlike the other incentive rates, the Competitive Rate Rider (CRR) does not require the use of BUS service. However, PP&L states that discounts under the CRR are limited to delivery charges and the CTC. PP&L M.B., p. 152, Footnote 75.

Company and its customers from a generation standpoint, and have no relation to delivery service. Thus, customers who do not utilize PP&L for their generation supply services would provide no benefit to the Company under the terms and conditions of the incentive rates. Therefore, PP&L argues, the rates should not be made available to these customers. Id., pp. 151-153.

The OCA objects to PP&L's proposals as they relate specifically to the Competitive Rate Rider (CRR). Since the discounts offered under the CRR would apply to the CTC (as well as the delivery charges), the OCA contends that such discounts could result in cost shifting through the CTC reconciliation process, in violation of the Act. The OCA argues that the Act requires the CTC to be nonbypassable, and therefore, prohibits the discounting of the CTC on behalf of any customer. OCA M.B. pp. 86-87.

The Competitive Intervenors also appear to object to PP&L's proposals, and advocate the necessity for the Company to eliminate its incentive rates as originally scheduled. The Competitive Intervenors cite the Commission's rulings in the PECO Restructuring Proceeding in support of their claim. Competitive Intervenors M.B., pp. 56-58.

SER/Gilberton also oppose PP&L's proposal with regard to the economic incentive rates. SER/Gilberton argue that such a proposal is anti-competitive because it discourages customers from choosing an alternative power supplier, and because such incentive rates would allow PP&L's regulated Electricity Delivery Group to undercut the future retail market. SER/Gilberton M.B., pp. 4-5. SER/Gilberton also argue, as does the OCA, that PP&L's proposal with regard to the CRR violates the requirement that the CTC be nonbypassable. Id., pp. 5-6.

PPLICA supports PP&L's proposal to extend the availability of incentive rates, and objects to the OCA's opposition to this proposal. PPLICA argues that it is the OCA's proposal to eliminate the incentive rates as originally planned that is contrary the Act. This is so, according to PPLICA, because the elimination of these rates would violate the rate cap, and would cause cost shifting since PP&L would then have extra resources available which must necessarily benefit either other rate classes or the Company's shareholders. Large Customers M.B., pp. 80-82. PPLICA also rejects the argument of The Competitive Intervenors that the Commission's PECO decision requires the elimination of the economic incentive rates. PPLICA contends that the PECO decision requires that all competitively priced services such as interruptible service, economic development rates and special contracts must be continued throughout the transition period. PPLICA R.B., p. 50.

As discussed above, we agree with the proposition that customers who switch to alternative energy providers and thus, no longer provide any benefits to the Company or its other ratepayers under the terms and conditions of certain rate schedules, should no longer be considered eligible to receive service under those rate schedules. Thus, we agree with the Company that any customer who chooses an energy provider other than PP&L should not be eligible for the benefits provided under the incentive rates in question. However, we find no reason to recommend that the termination dates of these incentive rates be extended as the Company proposes. PP&L's only reason in support of its proposal appears to be its fear that to terminate the incentive rates before the end of the transition period would violate the rate cap. However, as discussed above, we do not believe that the shifting of customers from one rate schedule to another for eligibility reasons represents a violation of the rate cap since no actual rates are being changed. Therefore, although we would advocate limiting the applicability of the various incentive rates to only BUSS customers of PP&L, we do not support the Company's proposal to extend the applicability of these rates beyond their original termination dates. Thus, we recommend that this proposal be rejected.

F. Interruptible Service Tariff Provisions

PPLICA objects to two PP&L proposals relating to interruptible service. The first of these concerns the Company's proposal to remove the limitations on the frequency and duration of economic interruptions that exist in its currently effective tariff. PPLICA contends that such a change diminishes the value of interruptible service without providing any compensatory decrease in rates. PPLICA argues that this effectively raises the cost for interruptible customers over and above the level of rates as of January 1, 1997, in violation of the Act's rate cap. Large Customers M.B., pp. 84-85.

In response to PPLICA's complaint, PP&L asserts that the limitations existing under the current tariff are not sufficient to protect other BUSS customers from the increasing average cost of service resulting from interruptible customers using energy when prices are high. PP&L M.B., pp. 146-147.

We agree with PPLICA that PP&L is attempting to decrease the value of its interruptible service in this proceeding without a reduction in rates. We do not find sufficient evidence to justify this change. Therefore, we recommend that PP&L's proposal to remove the limitations regarding the frequency and duration of economic interruptions be rejected.

The second proposal to which PPLICA objects relates to a change in the price charged to a customer who chooses to "buy through" an interruption. The current charge is the sum of the charges normally incurred under the rate plus the PJM billing rate for the buy-through period. The proposed charge is the otherwise applicable charge plus the estimated spot price of replacement capacity and energy. PPLICA contends that this proposed change should be rejected because 1) it was unsupported in Company testimony; 2) it provides customers with no certainty as to what the actual buy-through charge will be, nor does it provide a procedure to reconcile actual spot prices with the Company's estimates; and 3) it violates the Act's rate cap because if the Company's estimate is incorrect, the customer may pay more to buy through an interruption than it would under rates in effect on January 1, 1997. Id., pp. 86-87.

With regard to this objection, PP&L contends that its proposed estimated spot price more accurately reflects actual circumstances than a pre-established rate. It also states that the PJM tariff is currently being reviewed by FERC, and final provisions regarding sales and purchases relating to usage by interruptible customers during economic interruptions have not been determined. PP&L R.B., pp. 60-61. PP&L argues that its proposal cannot be said to violate the rate cap since it is not known whether or not a presently unknown spot price exceeds a presently unknown PJM billing rate. Furthermore, PP&L asserts that there is no reason to conclude that any errors it may make in estimating the spot price would be substantial, or would be detrimental to the interruptible service customer. Id., p. 61. PP&L states that the only alternative to its proposal "would be to wait until actual spot prices are known which may be long after the transaction has taken place, thereby defeating the ability of large customers to weigh the 'buy through' option against an interruption." Id.

Once again, we find the arguments of PPLICA to be persuasive. The Company is attempting to make changes to the terms and conditions of its interruptible service in this proceeding without providing sufficient evidence for such changes. Moreover, these changes do not appear to have any direct relationship to the main purpose of this proceeding, which is to restructure the Company's rates and services to promote a more competitive market for the provision of electric energy. Therefore,we recommend that PP&L's proposed change in its buy-through charge for interruptible service be rejected.

G. Transmission and Distribution Unbundling

In its proposed tariff, PP&L unbundled its rates into three components, namely, the delivery charge, the market price of energy, and the CTC. However, both PP&L and PPLICA agree that the delivery charge must be further unbundled into transmission and distribution components. This is so because customers who arrange to receive transmission service from PJM under its Open Access Transmission Tariff should not have to pay PP&L a rate that includes charges for transmission service that it is not providing. These customers should only be required to pay a distribution charge to PP&L. Thus, the unbundling of the delivery charge is necessary. PP&L M.B., pp. 157-158; Large Customers M.B., pp. 92-93. PPLICA's witness Baron provided worksheets detailing such an unbundling. PPLICA St. No. 1, Exhs. SJB-7-13. PP&L appears to accept PPLICA's proposed unbundling method. PP&L St. No. 12-R, p. 8.

Because this proposed unbundling of delivery service appears to be necessary and reasonable, and because there is no objection to it, we recommend that it be adopted.

H. Federal/State Jurisdictional Determination

FERC has determined that it has jurisdiction over the transmission of electric energy in interstate commerce by a public utility. Thus, there is a need to distinguish between facilities used for transmission and those used for distribution. PP&L further explains this need as follows:

> In Order No. 888, FERC found that once retail service was unbundled, there would be a need to draw a distinction between facilities that are used for transmission and those used for local distribution because, in determining the extend and scope of its exclusive jurisdiction, FERC has concluded that it has jurisdiction of retail transmission in interstate commerce to the point of local distribution. Order No. 888, 61 Fed. Reg. at 21,627. FERC also stated that it would defer to state recommendations on where to draw the jurisdictional line, provided that state regulators specifically evaluate seven specific indicators and any other relevant facts and make recommendations consistent with the essential elements of Order No. 888.

PP&L M.B. p. 156.

The seven indicators to which PP&L refers are as follows:

1. Local distribution facilities are normally in close proximity to retail customers.
2. Local distribution facilities are primarily radial in character.
3. Power flows into local distribution systems; it rarely, if ever, flows out.
4. When power enters a local distribution system, it is not recognized or transported to some other market.
5. Power entering a local distribution system is consumed in a comparatively restricted geographical area.
6. Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.
7. Local distribution systems will be reduced voltage. PP&L St. 12, pp. 17-18. Id., pp. 156-157

PP&L states that in applying these tests, it has concluded, subject to Commission and FERC approval, that its facilities operating at voltages of 69 kV and above are transmission facilities, and facilities operating at less than 69 kV are local distribution facilities. Id., p. 157.

No party has opposed the Company's analysis and proposal with regard to this issue. We also find the proposal to be reasonable and recommend that it be adopted.

I. Modifications to Terms and Conditions of Existing Tariffs

PP&L has proposed various modifications to existing tariff rules, which it explains as follows:

- Rule 4 is changed to indicate that the Company may upon request supply services over and above those which the Company would normally provide, if the customer agrees to pay the Company a fair and non-discriminatory price for those related services.

- Rule 9E was changed to indicate that the Budget Billing interest rate is changed from the number 1% per month to one-twelfth of the average of 1-year Treasury Bills for the months of September, October, and November of the previous year.

In Tariff 210, changes include the following:

- Rule A has been amended to exclude fuel supply disruption from qualifying for backup power supply.

- Paragraph E(5) has been added to Rule 6A to indicate that a customer-specific, fixed, per month CTC developed by the Company, which will equal 100 percent of the customer's estimated CTC revenue, will be applied if the customer elects to install on-site generation on or after January 1, 1999.

> Paragraph E(5) was based on Section 2808(a) of the Act, which permits recovery through a non-bypassable CTC of stranded costs from customers that install new on-site generation facilities. Under Section 2808(a), the CTC for such customer should be fixed and recover the customer's fully allocated share of stranded costs.

PP&L M.B., pp. 153-154.

Because these proposed changes to the Company's tariff provisions appear to be reasonable, and have not be opposed by any party in this proceeding, we recommend that they be adopted.

IX. PHASE-IN ISSUES

The Act mandates the following phase-in schedule for retail access:

> [T]he following schedule for phased implementation of retail access shall be adhered to unless a determination is made by the commission under subsection (c) [which allows for an additional six month transition period under certain circumstances]:
>
> (1) As of January 1, 1999, a maximum of 33% of the peak load of each customer class shall have the opportunity for direct access.
>
> (2) As of January 1, 2000, a maximum of 66% of the peak load of each customer class shall have the opportunity for direct access.
>
> (3) As of January 1, 2001, all customers of electric distribution companies in this Commonwealth shall have the opportunity for direct access.

66 Pa.C.S. § 2806(b).

The Act gives the Commission specific instructions:

The time line for the transition to and phase-in of direct access to competitive electric generation shall be in accordance with section 2806. 66 Pa.C.S. § 2804(11).

A. Phase-in Selection Method

PP&L's proposed phase-in schedule tracks that mandated by the Act. As described in the testimony of Mr. Henry W. Baumann, PP&L Sts. 14 and 14-R, PP&L proposes an initial sign-up period for each phase-in period during which all customers interested in participating in competition can notify the Company. If any rate classes are over-subscribed, PP&L will conduct a random selection among customers seeking to participate. PP&L St. 14-R, p. 4. Enron, OSBA and PPLICA witnesses believe that this methodology should not apply to the selection of commercial and industrial customers, based on the possibility that non-participating customers may suffer a competitive disadvantage over participating customers. *See* Enron St. 5.0, pp. 19-20; OSBA St. 1, pp. 51-52;. PPLICA St. 1, pp. 58-59.

PPLICA witness Stephen Baron asserts that the most appropriate methodology for selecting industrial customers is on a first-come, first-served basis, with the customer designating a desired level of load for participation. PPLICA St. 1, pp. 58-59. If there is an over-subscription of load, Mr. Baron proposes a pro-rata reduction to each subscriber's nominated load. To alleviate any remaining competitive disadvantages, Mr. Baron proposes that PP&L begin selection for the second phase and implement such a selection process by permitting retail access for up to 66% of peak load beginning January 2, 1999. PPLICA St. 1, p. 59.

Enron witness Mr. Bowen advocates a similar approach. Under Enron's proposal, Enron would be willing to accept the "first through the meter" approach, where Enron would supply the first portion of the customer's electricity received in a given hour and the EDC would supply the remainder. Enron would also be willing to "follow the customer's load" and provide a fixed percentage of its customers' load throughout the day. Enron St. 5.0, p. 20.

OSBA witness Robert Knecht suggests a variation on PPLICA's and Enron's approach to apply to commercial customers. He suggests that minimum levels of customer participation be set for the GS rate classes for each of two phase-in years. Under Mr. Knecht's proposal, if a rate class is over-subscribed and the random drawing produces too few customers, those few customers selected should be limited in the amount of their load that is subject to competition. OSBA St. 1, p. 53.

We reject these arguments. As discussed above, the phase-in schedule established under the Act is mandatory. The Act requires the Commission to establish regulations specifying that, within each customer class, the customers that are eligible for direct access during the phase-in period shall be determined by the Commission on a first-come, first-serve basis "unless otherwise determined by the commission . . . to prevent competitive disadvantages among similarly situated customers within a customer class." 66 Pa.C.S. § 2806(4). Neither Enron, OSBA nor PPLICA has made a showing of specific competitive disadvantage sufficient to justify a departure from the statutory presumption that the phase-in period will occur in the three stages established in Section 2806 on a first-come, first-served basis.[52] We reject the efforts of these intervenors to disrupt the "orderly" transition to a competitive generation market envisioned under Section 2806(14) of the Act, particularly in light of PP&L's express commitment to address any competitive problems on a case-by-case basis. PP&L St. 14, p. 5.

We also reject the various complex proposals for phasing in choice that would require customers to receive part of their service from their Alternative Supplier and part from their EDC. In the words of PP&L witness Dr. Tierney: "As a former regulator, I cannot imagine a phase-in proposal that would create more confusion among the public and more administrative difficulty for PP&L and the suppliers." PP&L St. 9-R, p. 50.

B. Grandfathering of Pilot Customers

Customers who are participating in the PP&L's pilot program can enroll in and will be selected for retail access as described above, with one exception. Customers who are participating in PP&L's pilot program, but which are not selected for the first or second phase of retail access can elect to be "grandfathered" into retail access. However, customers in the Primary and Transmission/Subtransmission groups who have load limits in the pilot program will be limited to that level of load when "grandfathered" into retail access. PP&L St. 14, pp. 4-

[52] Although the Commission found otherwise in *PECO*, PECO had already agreed to an accelerated phase-in schedule in its Partial Settlement. There is no settlement proposal in this case, nor does the record support a finding of competitive disadvantage, particularly for residential customers, who do not compete with each other.

5. As discussed above, the intervenors have failed to provide record support that would justify a departure from this proposal.

X. CODE OF CONDUCT AND COMPETITION ISSUES

In its Restructuring Plan filing, PP&L announced a voluntary restructuring of its retail electric business and a Retail Access Code of Conduct. *See* PP&L St. 13-R, Exh. RMG-4. PP&L implemented it Retail Access Code of Conduct contemporaneously with the filing of its Restructuring Plan, as another manifestation of PP&L's strong support for the development of a healthy competitive market for retail electricity. However, several intervenors have submitted separate proposals. We view these proposals as being designed to micromanage the competitive marketplace, handicap PP&L's efforts to compete in retail markets, and shield the new entrants from the very market pressures the General Assembly sought to invoke in adopting the Act. Such handicaps have no function in a truly competitive retail electric power market, and we reject them.

A. Purpose and Goal of Codes of Conduct and Competitive Access Rules

The Commission is charged under the Act with overseeing the development of a competitive retail electric generation market in a manner that treats both shareholders and customers fairly. Establishing standards of conduct to govern the relationship between electric distribution companies and their affiliated electric generation suppliers is an important part of ensuring that the competitive retail electric generation market will function in a way that fulfills the Act's directive to allow "electric generation suppliers and end-use customers to utilize and interconnect with the transmission and distribution system on a non-discriminatory basis at rates, terms, and conditions of service comparable to the transmission and distribution company's own use of the system to transport electricity from any generator of electricity to any end-use customer." 66 Pa.C.S.§ 2803.

The Commission is in the process of developing regulations concerning Customer Supplier Interaction at Docket No. M-00960890.F0011 and has opened a rulemaking to receive comments on the recommendations contained in the Final Report of the Competitive Safeguards

Working Group ("CSWG").[53] PP&L proposes that the Code of Conduct set forth in the testimony of Robert M. Geneczko, PP&L St. 13-R, Exh. RMG-4, should govern the relationship between its EDC and EGS until regulations of general applicability are adopted.

As Dr. Kalt explained at the hearing, in addressing competitive safeguards the Commission has at least three options: (1) prevent extension of remaining monopoly power; (2) handicap utility affiliates; or (3) affirmatively support or subsidize rivals. PP&L St. 1-R, pp. 9-12. Only the first option, however, truly promotes and protects competition. As Dr. Kalt confirmed, "actions and advantages of the unregulated affiliates of an incumbent utility that should be regulated or eliminated are solely those that derive from leveraging of continued ownership and control of monopoly functions (i.e., transmission and distribution). Actions and advantages not so derived represent the tools of competition that the unregulated affiliates bring to non-monopoly marketplaces, and the consumer will be harmed if denied access to these." PP&L St. 1-R, pp. 9-10.

The second option, handicapping utility affiliates, will benefit competitors, but will harm consumer interests. Such handicaps would subject utility affiliates to complex and cumbersome reporting, operational, and compliance specifications not shared by their rivals and would result in the Commission promoting the interests of certain competitors, rather than competition itself. See, PP&L witness Dr. Kahn at PP&L St. 18-R, p. 6; also PP&L M.B. at pp. 162-165.

The third alternative, supporting or subsidizing PP&L affiliate rivals is, again, not in the best interests of consumers. For example, "marketing restrictions that raise the costs of the incumbent or deny the incumbent the use of assets that consumers value (such as brand name) are the functional equivalent of a subsidy to rivals, who do not have to bear such costs or build up such assets to remain competitive in the marketplace. This policy strategy is consistent with the interests of PP&L's rivals, but not the interests of consumers." PP&L St. 1-R, pp. 11-12.

Enron witness Mr. Dirmeier is incorrect when he argues that: "My position does not handicap anyone; rather it is intended to place all competitors on the same initial footing, recognizing that, in reality, PP&L has a decided initial advantage that it seeks to prolong." Enron

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[53] The CSWG was formed in early 1997 to address the role and scope of competitive safeguards in a restructured retail electric generation market. The CSWG issued its Final Report to the Commission on October 6, 1997, which contains ten principles adopted by the working group. PP&L was a member of the CSWG and indicated its support for the ten principles by signing the Final Report.

St. 6.1, p. 8. To make all competitors equal at the outset, the Commission would have to take into account the numerous inherent advantages and disadvantages of competitors, some based on efficiency and some based on basic cost differences. Such solutions would deprive customers of the benefits of more efficient producers. Instead, the Commission should adopt standards of conduct narrowly tailored to fulfill the purposes of the Act. If PP&L provides non-discriminatory access to regulated facilities, and does not engage in cross-subsidization or improper exchange of customer data, then any advantages it has in the marketplace derive from its ability to give consumers something they want.[54]

B. Existing Prohibitions on Anticompetitive or Discriminatory Behavior

Any additional protections required by the Commission should be considered in light of the pervasive safety net of competition protection that already exists. Existing antitrust laws, the Federal Power Act and the FERC's Order Nos. 888 and 889 contain numerous prohibitions on and protections against anticompetitive or discriminatory behavior. Moreover, Section 2811 of the Act gives the Commission the authority to monitor competitive conditions and conduct investigations.

1. Antitrust Laws

The Commission need not rewrite the antitrust laws in order to fulfill its mandate under the Act. The sole objective of the federal antitrust laws is to ensure a competitive economy. *United States v. South-Eastern Underwriters Ass'n,* 322 U.S. 533 (1944). The federal antitrust laws have, for over a century, focused on protecting fair competition in open markets.

The antitrust laws cover a wide variety of competitive injuries normally associated with the transition to competitive markets. These include among others, prohibitions against tying, monopolizations, denial of reasonable access, monopoly leveraging and price fixing. Most importantly, however, antitrust enforcement agencies and the courts have extensive experience in balancing the procompetitive benefits of efficient operation against potential harm to competitors. *See Tenneco Gas v. F.E.R.C.,* 969 F.2d 1187, 1204 (D.C. Cir. 1992) ("[T]he

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[54] Neither the antitrust laws nor a workably competitive market require such a radical approach designed to handicap incumbents and subsidize new entrants. *See, e.g., Brown Shoe v. United States*, 370 U.S. 294, 320 (1962).

Commission 'must also consider the extent to which various remedies would interfere with any efficiencies that may stem from pipeline integration into marketing.' . . . 'The selection of a remedy . . . is thus a delicate balancing process involving the degree of competitive harm, the effectiveness of the remedy, and the competitive and administrative costs of the proposed remedy'").[55]

2. Federal Power Act

The Supreme Court has held that the FERC's regulatory mandate "clearly carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate utility operations." *Gulf States Utilities Co. v. F.P.C.,* 411 U.S. 747, 758-60 (1973) (*"Gulf States"*); *see also F.P.C. v. Conway Corp.,* 426 U.S. 271, 279 (1976). This mandate has been held to include advancing the "fundamental national economic policy" of competition and economic efficiency expressed in the antitrust laws. *Gulf States,* 411 U.S. at 759.[56]

In a case frequently cited by the courts and the FERC for this proposition, *Northern Natural Gas Company v. F.P.C.,* the Court of Appeals held that "the basic goal of direct governmental regulation through administrative bodies and the goal of the indirect governmental regulation in the form of antitrust law is the same — to achieve the most efficient allocation of resources possible." 399 F.2d 953, 959 (D.C. Cir. 1968). Indeed, the Supreme Court has observed:

> Consideration of antitrust and anticompetitive issues by the Commission, moreover, serves the important function of establishing a first line of defense against those competitive practices that might later be the subject of antitrust proceedings.

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[55] The Court quoted approvingly from the comments of the United States Department of Justice and the Federal Trade Commission submitted in Response to the Notice of Inquiry into Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines, F.E.R.C. Stats. and Regs, Regulations Preambles 1986-1990 ¶ 35,520 (1986).

[56] Under the Federal Power Act, the obligation of utilities not to discriminate exceeds the burdens imposed by the antitrust laws on firms acting unilaterally. Thus, under Section 205 of the FPA, public utilities have an affirmative obligation not to "make or grant any undue preference or advantage" or to "maintain any unreasonable difference" in rates, practices, or facilities. 16 U.S.C. § 824c(b). Similarly, under Section 212, rates, charges, terms, and conditions for transmission ordered under Section 211 shall not be "unduly discriminatory or preferential." 16 U.S.C. § 824k(a) (Supp. 1995).

3. FERC Order Nos. 888 and 889

In Order No. 888, the FERC required all public utilities that own, control or operate transmission facilities to file open access transmission tariffs, to take transmission service for their own new wholesale sales and purchases under those tariffs, to develop and maintain a same-time information system to give all transmission users the same access to transmission information that the public utility enjoys and to separate transmission from wholesale merchant functions and communication. The FERC required utilities in Order No. 889 to adopt standards of conduct designed to functionally separate transmission and wholesale merchant functions and to prevent transmission providers from giving their wholesale merchant counterparts within the public utility an undue preference over their customers though the exchange of "insider" information between the company's system operators and employees of the public utility, or any affiliate, engaged in wholesale merchant functions. *See* 18 C.F.R. § 37.4. PP&L plans to extend its Order No. 889 Code of Conduct to its retail transmission operations. PP&L St. 13, p. 5.

C. Basis and Extent of PP&L's Proposed Code of Conduct

PP&L's proposed Code of Conduct will govern the relationship between PP&L's Generation Supply Group and its the Electric Delivery Group.[57] The Code of Conduct is intended to control dissemination of confidential customer information; restrict access to competitive information; prevent cross-subsidies between regulated and unregulated operations; and prevent discriminatory practices. It is designed to ensure that employees of the Electric Delivery Group engaged in transmission system operations function independently of the Generation Supply Group employees who are engaged in the purchase and sale of electric energy, in order to ensure that the Electric Delivery Group does not use its access to information about transmission to benefit unfairly its own or the Electric Generation Group's sales.

PP&L's proposed Code of Conduct is set forth in PP&L Exhs. RMG 2 and RMG 4; it is discussed in PP&L St. 13-R. PP&L envisions that this Code of Conduct will remain in effect until such time as the Commission adopts regulations establishing permanent standards of

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[57] At the time of the hearing, PP&L had not yet determined the names under which its Electric Delivery Group and Generation Supply Group will do business. PP&L's Electric Delivery Group is now doing business as "PP&L Access," and PP&L's Generation Supply Group is marketing energy to wholesale and retail customers under the name "PP&L Energy Plus."

conduct. PP&L's proposed Code of Conduct tracks the principles adopted by the Competitive Safeguards Working Group. Specifically, the Retail Access Code of Conduct provides for:

- Open, Non-Discriminatory Access to and Pricing of Regulated Monopoly Services (PP&L Exh. RMG 2, pp. 4-5; PP&L Exh. RMG 4, pp. 1-2).
- Prohibitions on Conditioning (Tying) of Access to Monopoly Services on Purchase from Generation Supply (PP&L Exh. RMG 2, pp. 4-5; PP&L Exh. RMG 4, p. 2).
- Non-Discriminatory Dissemination of Disclosed Market and Competitively Sensitive Information (PP&L Exh. RMG 2, pp. 3-5).
- Confidentiality of Customer and Supplier Information (PP&L Exh. RMG 2, p. 4; PP&L Exh. RMG 4, p. 1).
- Segregation of Personnel and Information by Group (PP&L Exh. RMG 2, p. 1; PP&L Exh. RMG 4, p. 1).
- Restriction of Information Transfer Via Personnel Assignment (PP&L Exh. RMG 2, pp. 2-3; PP&L Exh. RMG 4, p. 1).
- Separate Cost Allocation, Books, and Records (PP&L Exh. RMG 2, p.5; PP&L Exh. RMG 3, p. 2).
- Enforcement of Employee Education in the Codes of Conduct (PP&L Exh. RMG 2, pp. 5-6; PP&L Exh. RMG 3, p. 2).
- Compliance Reporting, Auditing and Dispute Resolution (PP&L Exh. RMG 2, p. 6; PP&L Exh. RMG 3, p. 2).

These rules and protections will assure a fair and open market without unfairly handicapping PP&L as a competitor.[58]

D. Additional Competitive Restrictions Proposed

1. Prohibit Use of "PP&L" Name

Mr. Dirmeier would have the Commission believe that Enron faces a Herculean task overcoming the single brand of PP&L. Enron St. 6.1, p. 2. Similarly, Mr. Dirmeier claims that

[58] PP&L has chosen not to include Subsections (1) - (6) as listed in the "Code of Conduct" section of the common briefing outline adopted in this case. The relevant provisions of PP&L's Code of Conduct are referenced in the bullet points above and throughout the remainder of this section.

although it is possible that some entrants will find advantages of their own, overcoming the name and goodwill advantages of the incumbent EDCs will be daunting at best. Enron St. 6.1, p. 9.

This argument simply is not correct. Enron and many other potential competitors have a strong market presence and have the resources to overcome the single brand name of PP&L.[59] To date, [more than thirty] firms are licensed to be alternate retail suppliers under the Act.[60] The list of licensed generation suppliers includes companies with considerable experience and success in unregulated markets or in markets with partial deregulation. PP&L's potential competitors include numerous other vertically integrated utilities based in other jurisdictions, independent power producers and marketers, energy service firms such as Enron, and retailing companies such as American Express that have expressed interest in entering electricity markets[61].

a) The use of the name "PP&L" by the Generation Supply Group will not lead to customer confusion.

Enron witness Mr. Dirmeier asserts that PP&L's proposed Code of Conduct would lead to customer confusion because it does not go far enough to prevent PP&L's non-regulated operations from using the name of the EDC in a manner in which customers could reasonably imply that the electric generation supply is being provided by PP&L as the EDC rather than PP&L as the electric generation supplier. Enron St. 6.0 , p. 31-33; *see also* Enron St. 6.1, pp. 1-4 .

Mr. Dirmeier is incorrect. There will be no customer confusion under PP&L's proposal by the use of the name "PP&L Energy Plus" because as described above, by Mr. Geneczko,

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59 Enron has a significant, national market presence. Enron advertised during the Super Bowl telecast in January 1997 and has been advertising its brand name heavily throughout the country. Enron witness Mr. Shapiro stated that one of Enron express corporate objectives is to become the premier seller of electric energy at retail in the United States. Tr. 1605 (8/26/97). Mr. Shapiro agreed at the hearing that Enron is taking steps that any competitor would in trying to break into new market. Tr. 1605-06 (8/26/97). For example, Mr. Shapiro admitted that "It is very likely that one of the products that we will try to bring into the marketplace is a lower priced product than our other competitors." Tr. 1607 (8/26/97).

60 In addition, 89 firms have registered as members of PJM, with the reasonable presumption being that most of them have intentions of participating in the marketplace in which PP&L will operate.

61 The Commission in the PECO Order did not prohibit PECO's competitive affiliates from using PECO's name. PECO at 131.

PP&L will clearly and explicitly distinguish delivery service and generation supply service as separate operations. Tr. 553 (8/18/97).

Moreover, *prohibiting* PP&L's Generation Supply Group from using the PP&L name will lead to customer confusion and may deceive customers. Dr. Kalt put this succinctly at the hearing:

> It is inappropriate to in any way deceive consumers and imply that they are not getting service from some company. Taking information out of a market is not plausibly a sound public policy. The reason for that, as I have said, is that information to consumers is valuable because they value such things as peace of mind, assurance, et cetera, reputation.

Tr. 459 (8/18/97). Enron witness Mr. Dirmeier acknowledged that it would be wrong to mislead customers as to who is providing their power. Tr. 687 (8/19/97). As recognized by Mr. Dirmeier, a name benefits consumers by providing information and assurance. Tr. 439 (8/18/97). Mandating the use of a different name would deprive consumers of the added assurance of quality and price derived from putting the parent's reputation at stake.

b) PP&L's Name is a Shareholder Asset.

The name PP&L and the good reputation associated with the name are shareholder assets, and, as such, are not included in the ratebase. The name and reputation of a utility therefore are not assets to which ratepayers have a claim. Ratepayers have never had to pay through rates a return on the value of goodwill or for enhancement of the utility's name, and name and reputation are cost free to PP&L's customers. Thus, there is no ratepayer harm in allowing PP&L to continue to use its name, or in allowing its affiliate to use the name.

PP&L's name <u>and</u> reputation do not, as Mr. Dirmeier claims, "result [from] its providing regulated monopoly service under the quality service guidelines established, in this jurisdiction, by the Pennsylvania Public Utility Commission[.]" Enron St. 6.1, p. 10. Indeed, whether a utility's brand name is a good one or a bad one is not a function of utility assets. If that were true, all regulated utilities in the United States would have good reputations.[62] As Dr. Kalt stated:

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62 Mr. Dirmeier agreed that some utilities do not have good reputations with their customers. Tr. 688 (8/19/97).

> We're all aware that some utilities around the country have good brand names, some of them have real bad brand names. And that fact suggests, of course, that it's not a function of their ownership of essential facilities, T & D, the natural monopoly function that's generating the brand name. Otherwise they'd all have great brand names. . . . I think you cannot conclude that the good brand name's a function of the natural monopoly attributes or just a fact of regulation over the last 75 years. Tr. 518 (8/18/97).

c) Prohibiting the Use of the PP&L Name is Anti-Competitive and Will Harm Consumers.

The various ways in which firms distinguish themselves and the advantages that certain firms have over others in a competitive market benefit consumers because they allow the firm which possesses them to deliver something that consumers want, or to deliver what consumers want on better terms. These advantages and distinctions may arise through luck, savvy, or history. Firms' distinguishing characteristics may include brand names that are well-respected, convenient locations that reduce transportation costs or a base of potential customers encountered in related markets. The process of rivals each trying to find their own advantages and overcome the advantages of their competitors is what allows consumers to "win." PP&L St. 1-R, p. 14. The Act, like the antitrust laws, does not mandate that all such advantages and disadvantages be leveled. It was not designed to be an assistance program for disadvantaged competitors. *See, e.g., United States v. Syufy,* 903 F.2d 659, 668 (9th Cir. 1990); *Olympia Equip. Leasing Co. v. Western Union Tel. Co.*, 797 F.2d 370, 374 (7th Cir. 1986).

d) It is Not Appropriate For the Electric Generation Supply Group to Have to Pay a Royalty or Fee to Use Its Name.

Enron witness Mr. Dirmeier asserts that if there is value in PP&L's name, then the name should not be conferred without compensation. Enron St. 6.0, pp. 28-29, Enron St. 6.1, pp. 10-11. The payment of a royalty is inappropriate for several reasons. First the utility's name is not a ratepayer asset, as discussed above. Requiring PP&L's Generation Supply Group to pay a royalty for the use of the PP&L name would constitute a taking without just compensation. The imposition of a royalty would constitute a requirement that a regulated company dedicate its intangible assets, for which ratepayers have never paid and do not own, to the ratepaying public. Second, a percentage royalty, which is one type of royalty that has been proposed in other jurisdictions, does not bear any relationship to costs or benefits from the association of the affiliate with the utility and would be difficult if not impossible to value. It is also questionable whether the Commission has the authority to require an unregulated, private business to pay a royalty to affiliated utilities' ratepayers. Such an order may be an improper extension of ratemaking authority. Absent a showing that ratepayers will be charged an unreasonable cost for service as a result of a transaction between a regulated company and its affiliate, the Commission does not have the authority to order a regulated company to charge its affiliate for benefits allegedly conferred on the affiliate as a result of its relationship with the regulated company.

2. Ancillary Services

Several parties, including Enron, *See* Enron St. 3.0,contend that in addition to revenue cycle services, ancillary services also should be unbundled. These proposals are not only beyond the intent of the Act, they are beyond the Commission's jurisdiction as well. Ancillary services are services offered in connection with the transmission of electric power. They are clearly transmission-related not distribution-related services. As such, they are within the exclusive jurisdiction of the FERC. *See* Section X.D.4. Indeed, the FERC unbundled anciallary services in Order No. 888.

3. Prohibit Joint Marketing

PP&L's proposed Code of Conduct provides that the Electric Delivery Group will not favor the Generation Supply group in any marketing of energy supply products. In addition, PP&L witness Mr. Geneczko agreed during the hearing that PP&L's Generation Supply Group will have access to bill inserts on the same terms and conditions as other electric generation suppliers. Tr. 586 (8/18/97).

As clarified by Mr. Geneczko at the hearing, PP&L's Electric Delivery group may engage in joint marketing of energy supply products with PP&L's Generation Supply group, but will only do so as long as comparable opportunities are available to other suppliers and the purpose of the joint effort is economic development. Tr. 554 (8/18/97). The Electric Delivery group still has an interest and community responsibility to facilitate economic development, but is indifferent, however, as to which alternate suppliers provide the energy part of the package. PP&L St. 13-R, p. 24. It will inform alternative suppliers of any such arrangements on a "rather immediate" basis, which may include posting such arrangements on OASIS. Tr. 583 (8/18/97).

4. Require that Surplus Power Be Offered to Alternate Suppliers

Several intervenors suggested that PP&L should be required to offer any surplus power to Alternate Suppliers. Enron St. 6.0, p. 37. Such a requirement would be a drastic intrusion into the competitive process that the Act has determined "will no longer be regulated . . ." 66 Pa.C.S. § 2802(14). Moreover, such a requirement would clearly be beyond the Commission's jurisdiction. The sale of surplus power to Alternate Suppliers is a wholesale transaction that falls squarely within the FERC's exclusive jurisdiction under the Federal Power Act ("FPA"). Section 201 of the FPA gives the FERC plenary, exclusive and non-delegable jurisdiction over such sales. 16 U.S.C. § 824(b)(1). *Federal Power Comm'n. v. Southern California Edison Co.*, 376 U.S. 205, 216 (1964) (FERC jurisdiction is plenary and extends to all wholesale sales in interstate commerce except those which Congress has made explicitly subject to regulation by the States). *See also Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 53 (1986); *Mississippi Power & Light Co. v. Mississippi*, 487 U.S. 354, 374 (1988). The fact that power will ultimately be used to serve retail customers does not change the wholesale nature of the transaction. *Pacific Gas and Elec. Co.*, 77 FERC ¶ 61,265 at 62,088 n.43 (1996).

5. Require the Delivery Group to Make Non-Delivery System Information Available to All Alternate Suppliers

Enron witness Mr. Dirmeier suggests the need for an internet bulletin board to document *all* information shared between the Electric Delivery Group and the Generation Supply Group. This recommendation is far too broad and is not supported by any provision in the Act. As explained in Mr. Geneczko's rebuttal testimony, Company personnel necessarily will meet from time to time to discuss matters of a corporate nature, such as personnel, or matters relating to joint work outside of the Electric Delivery group's service territory. Much of the information discussed in these meetings is confidential in nature, the sharing of which is not necessary to achieve a competitive retail electric generation market. PP&L St. 13-R, p. 15. Thus there is no reason or authority for the Commission to address such non-delivery information in this proceeding.

6. Prohibit Market-Driven Contracts Before Choice is Implemented

Enron has proposed that in the time before direct access begins to be phased in, PP&L should not be permitted to enter into "market priced" contracts unless PP&L first offers to competitive suppliers the opportunity to bid to provide service to the customer and that customers who entered into such contracts subsequent to the date on which the Act was passed to cancel such contract. Enron St. 6.0, p. 46. Mr. Dirmeier admits that he has no information that would lead him to believe that PP&L is engaging in the behavior he would prohibit.

As discussed by Mr. Kalt in his rebuttal testimony, requesting the Commission to "open up" pre-existing market-based contracts is a transparent attempt to gain Commission intervention in a competitive market to favor PP&L's competitors. As explained by Dr. Kalt,

> long term contracting is a mechanism by which customers -- particularly the relatively large and sophisticated kinds of customers commonly seeking long term contracts -- can visit the force of impending competition on a utility's electricity sales even before the commencement of choice. The reason is obvious: the pending opening of choice can enhance the bargaining position of a utility's customers regarding price, length of contract, and other terms and conditions. The presence of choice on the near horizon enables customers to credibly threaten to take only standard tariffed service and/or insist on near-term termination rights that would enable them to depart for other suppliers upon the start of choice.
>
> In short, customers are better off having the option of signing long term purchase contracts with a utility in the face of pending open access than they would be if their only option were to stay with a utility's standard tariffed service and exercise choice upon a future date. It is understandable that rivals would like to expand the number of customers they can chase upon the opening of access, but it is not in customers' interests nor does competition require that customers be required to wait for access in order to realize some of its benefits. PP&L St. 1-R, pp. 51-52.

7. Require a Uniform State-Wide Code of Conduct

The Commission intendes to adopt uniform, state-wide standards of conduct. Until those standards are adopted, however, we agree with PP&L that its proposed Code of Conduct should govern the relationship between its Electric Delivery Group and Generation Supply Group.

8. Require PP&L to Permit Alternate Suppliers to Bill for Distribution Services and Be the Sole Contact for Customer Service

The Commission currently permits two billing options: (1) the EDC will provide a bill for all basic services to customers who have not chosen a generation supplier and those who have chosen a generation supplier but asked to receive a single bill; and (2) the EDC will provide a bill for all basic services except generation to customers who have chosen a generation supplier but asked to receive separate bills from the supplier. As explained below, consideration of a "third" billing option, permitting alternate suppliers to bill for distribution services should await the forthcoming Commission rulemaking.

9. Limitations on the Provision of Non-Utility Services

Several intervenors have raised concerns over the plan of PP&L's Electric Delivery Group to continue marketing products such as electronic thermostats, Power Watch™ devices and Heat Comfort™ controls. *See* Enron St. 6.0, p. 18; Tr. 570 (8/18/97). These concerns are misplaced. Prohibiting the EDC from providing these services is not required under the Act, and is by no means a prerequisite to carrying out the primary purpose of the Act – "to permit retail customers to have access to a competitive *generation* market as long as safe and affordable transmission and distribution service is available" at current levels of reliability. 66 Pa.C.S. § 2802(3). There is no indication that the General Assembly had a concern with utility involvement in non-generation products and services, as long as customers have fair and non-discriminatory access to a competitive generation market and competitive suppliers of electricity.

E. Further Unbundling of Distribution Rates or Services

1. Metering, Billing and Collection Services

Several intervenors have argued in this proceeding that customer metering and billing services should be unbundled from other EDC customer services in order to create an additional opportunity to provide value-added services to consumers. *See* Enron St. 4.0, p. 3. As noted by the Commission in the PECO Order, the Commission has addressed these issues through various working groups, rulemakings and Orders. Although section 2804(3) of the Act provides that "the Commission may require the unbundling of other services" in addition to basic unbundling of transmission, distribution, and generation services, the Commission concluded in the PECO Order that Section 2807 of the Act, which sets forth the duties of electric distribution companies, does not assume that any additional unbundling is required and that "EDC's continue to have the duty to provide all distribution services, including metering and billing, in compliance with existing Commission requirements." PECO Order at 138-39. The record established in this proceeding mandates the same conclusion.

a) Customer Billing

Several of the intervenors have argued that a customer should be able to receive a single bill from its EGS that includes EDC charges. *See* Enron St. 5.0, pp. 6-7. Section 2807(c) of the Act provides that the EDC may be responsible for billing customers for all electric services but grants the customer the right to choose to receive a separate bill from its generation supplier. The Act itself explicitly specifies a presumption that the EDC shall have the duty to provide a single bill, including competitive generation services, to all customers unless the customer chooses to receive a separate bill directly from its EGS. The Commission has initiated a rulemaking to address the manner and details of the interaction between customers, suppliers, and EDCs at Docket No. M-00960890.F0011.

The Commission recognized in the PECO Order that there may be potential benefits of such proposals but concluded that it is inappropriate to unbundle billing based on the record presented in that proceeding. The Commission directed PECO to provide all billing services, including billing for generation services, unless a customer indicates a preference to receive a separate bill directly from the supplier for generation services. PECO Order at 139. The record in this proceeding mandates the same conclusion.

b) Metering

As indicated in the Commission's rulemaking at Docket No. L-00970120, the Commission has decided that it is unnecessary to unbundle metering as a competitive service at this time. In that rulemaking, the Commission outlined the standards and procedures to ensure that customers have real options for competitive metering while retaining all physical work related to metering as a regulated EDC function.

The Commission decided in the PECO Order that all customers may, in conjunction with their EGS, request use of a "qualified meter" that has been approved by the Commission based on the recommendations of a working committee composed of interested parties. The Commission will ensure that the list of qualified meters includes all meters necessary to support market services such as two-way communication, remote readings, time-of-use capability, and net metering.

2. Require Delivery Group to Supply Customers Not Eligible to Choose Alternate Suppliers During the Phase-In.

Various parties asserted that PP&L had decided that customers not yet eligilble to choose would be served by its competitive generation supplier during the phase-in period. However, as PP&L explained, customers not yet eligible to choose would be served under traditional regulated rates. Tr. 743 (8/19/97). This treatment is consistent wiht the PECO Order, pp. 132-134; Order on Reconsideration, pp. 20-21.

F. "Open Architecture" Standards for Metering and Other Distribution Services

PP&L witness Anthony M. Osmanski indicated PP&L's support for open system architecture for all metering services hardware and software. PP&L St. 21-R, p. 3. PP&L advocates the use of the standards currently being developed by the IEEE SCC-31 Standards Coordinating Committee. *Id.* PP&L believes that the installation of the actual metering hardware should remain part of the regulated distribution services. The energy information exchange would be provided as a "Standardized and Open Architecture" data stream to a customer interface. This interface gateway should be the marketable product open to competition, providing a receptacle for data and a gateway to communication and information services. The market may be driven to provide this information service with no initial cost to the customer. PP&L St. 21-R, p. 12.

G. Treatment of Partial Payments by Customers

Enron witness Raymond W. Bowen, Jr. suggests that payments received from customers by PP&L should be applied to services provided by PP&L and services provided by the supplier on a pro rata basis. Enron St. 5.0, pp. 16-17.

As Mr. Bowen acknowledged at the hearing, however, if payments are provided to the supplier on a pro rata basis, the amount of the EDC's non-recovery will increase. Tr. 1339-40 (8/22/97). Despite this fact, Mr. Bowen asserts, without foundation, that an increase in the amount of the EDC's non-recovery would not increase the EDC's cost of providing service. *Id.*

The Commission has already considered and rejected the pro rata payment approach advocated by Enron. *See* Final Order Re: Guidelines for Maintaining Customer Services at the Same Level of Quality Pursuant to 66 Pa. C.S. § 2807(D), and Assuring Conformance with 52 Pa. Code Chapter 56 Pursuant to 66 Pa. C.S. § 2809(E) and (F) (entered July 11, 1997). Instead, the Commission decided that the "priority" method of applying partial payments is preferable to the "prorata" method, particularly in terms of administering the process and complying with applicable Chapter 56 provisions at 52 Pa. Code §§ 56.23 and 56.24. Order at 32-33.

H. Allocation of PJM Intertie Capacity

Enron witness Richard D. Tabors urges the Commission to require PP&L to make its PJM-allocated intertie benefits available to either its former retail customers who choose an alternative generation supplier or to that customer's supplier. Enron St. 8.0, p. 3. The relief requested by Enron, however, is beyond the scope of the Commission's jurisdiction, power and authority.

It is well-established that the rates, terms and conditions of wholesale sales of power by public utilities fall squarely within the FERC's exclusive jurisdiction under the Federal Power Act ("FPA"). Section 201 of the FPA gives the FERC plenary, exclusive and non-delegable jurisdiction over such sales. 16 U.S.C. § 824(b)(1). *See, e.g., Mississippi Power & Light Co. v. Mississippi*, 487 U.S. at 374. Indeed the FERC considered the very issue in its recent order on the restructuring of the PJM Interconnection. *See Pennsylvania-New Jersey-Maryland Interconnection*, 81 FERC ¶ 61,257 (1997).

I. Customer "Slamming"

Section 2807(d) of the Act requires the Commission to promulgate regulations to ensure that customer consent is obtained prior to a change of electric suppliers. The Act allows an authorized change to be initiated once an EDC has received direct oral confirmation from the customer or written evidence of the customer's consent. The Commission issued a Proposed Rulemaking Order Establishing the Standards for Changing A Customer's Electric Supplier at Docket No. L-00970121 in April 1997, which provides that a change of a customer's supplier may be initiated once the EDC has received direct oral confirmation from the customer or written evidence of the customer's consent. Under the proposed rules, "written evidence of the customer's consent" is limited to a document signed by the customer, the sole purpose of which is to initiate a change of electric suppliers.

Enron witness Mr. Bowen believes that the "written evidence" requirement should not require "direct" written communications from the customer through a letter of authorization or an agency agreement, nor should it require that the customer execute the document submitted to the EDC. Rather, Enron believes that "written evidence of the customer's request" should include any document which evidences to the EDC that customer consent was received by the supplier. Enron St. 5.0, p.24.

PP&L disagrees with this approach and argues that incidences of slamming will be minimized if the customer is directly involved in the process. Tr. 1236 (8/21/97). PP&L's proposal accomplishes the same goal as the Commission's proposed regulations—to ensure that a customer consents to the switching of its generation supplier. Under PP&L's proposal, an alternative supplier may provide written notification to PP&L of a customer's decision to purchase electricity from that alternative supplier. The Company will then send the supplier's written notification to the customer and request that the customer inform the Company if any of the information is incorrect or inaccurate. If the customer does not respond, the Company will assume the supplier's notification information is correct. PP&L St. 14, p.6.

XI. CUSTOMER EDUCATION

PP&L's Customer Choice Education Program ("CCEP") is clearly focused on carefully developing and providing customers with educational information that will give them the information they need to make informed choices. As explained by PP&L's witness, Dawn G. Lennon, the key principles of PP&L's CCEP are:

- PP&L will provide clear, balanced and practical explanations of what customer choice is, how it works, what the risks and trade offs are, and how to select an electricity supplier.
- PP&L will be recognized as a consistent, reliable and trustworthy source of information on customer choice.
- PP&L will separate customer choice education efforts from sales and marketing initiatives.
- PP&L will produce customer choice educational materials which are easy to read and understand and which meet high standards of objectivity.
- PP&L will pursue partnerships with the Commission and with educational, service, and consumer organizations in the development, implementation, dissemination, and evaluation of educational materials and programs on customer choice.
- PP&L will continue its customer choice education efforts to address new needs and changes, ensure understanding, and provide ongoing support for customers.

PP&L St. 17, pp. 4-5. PP&L's CCEP includes reliance on community based organizations ("CBOs") and other stakeholder groups to assist PP&L in its education efforts.

PP&L's Customer Choice Handbook is the centerpiece of its CCEP. It will include an overview of the restructuring of the electric utility industry, an explanation of customer choice and how it works, consumer protection tips, worksheets for determining the customer's choice of suppliers and answers to important questions about the retail access market place.

In addition to the Handbook, PP&L will offer interactive telephone technology and presentations by customer choice educators. PP&L will sponsor a Customer Choice Education Advisory Committee composed of leaders from consumer, education and community organizations to oversee the development of customer choice educational workshops for target groups. The group will develop the details of the consumer education plan, commission the development of materials, design the methods of dissemination, analyze evaluation research on the program and ensure that PP&L's consumer education program provides balanced and unbiased knowledge to customers.

A. Statewide Customer Education Program

PP&L's CCEP is designed to be implemented on a local level by PP&L and various community based organizations. Nevertheless, PP&L will support and actively participate in a statewide effort if the Commission ultimately determines that such an effort is appropriate. As Ms. Lennon emphasized, however, a statewide effort alone cannot effectively educate customers. PP&L St. 9-R, p. 48.

As suggested by OCA witness Barbara Alexander, individual market participants should supplement any statewide effort with their own customer education activities. OCA St. 5, p. 17. It is not only appropriate to allow and encourage the various market participants to play a role in informing consumers, but it is also not realistic to bar PP&L — or others — from distributing information to their existing and potential customers. PP&L strongly disagrees with Enron witness Mr. Bowen's recommendation that the Commission or an independent third party under the Commission's supervision prepare and distribute educational information on a centralized basis. Enron St. 5, p. 28-29. While a Commission-led customer education program can be part of a successful education campaign, it cannot substitute for local customer education programs, which are best developed and implemented on a service territory by service territory basis.

Moreover, PP&L has an obligation under the Act to provide balanced unbiased information from which customers can make an informed decision to exercise choice. Specifically, Section 2807(d)(2) of the Act requires each EDC to provide adequate and accurate customer information to enable customers to make informed choices. Section 2807(d)(3) of the Act further directs the Commission and each electric distribution company to implement a consumer education program informing customers of the changes in the electric utility industry prior to the implementation of any restructuring plan.

The Commission recently initiated a proceeding regarding the Creation and Implementation of a Statewide Consumer Education Program for Electric Restructuring in the Commonwealth of Pennsylvania, Docket No. M-00981036 (entered Jan. 16, 1998). In its Order, the Commission solicited comments on a comprehensive consumer education program which will include a statewide media campaign and a local community initiative. As the Commission recognized, "[p]articipation in a statewide media campaign or the use of CBOs on a local level does not eliminate the requirement that the EDCs actively participate in the comprehensive consumer education program at the local level." Order at 7.

PP&L continues to believe that the most useful tools to educate are reference materials (print, audio and website) that customers can access and revisit. While the use of mass media can be an effective tool to create customer awareness, it must be followed by information such as brochures, pamphlets, direct mail and other forms of communication to expand the "soundbite" messages of a media campaign. The best way to educate is to mobilize and equip people in the community using community-based organizations. Tr. 2009 (8/29/97).

B. Specific Milestones and Budgets

PP&L provided the OCA with a five year preliminary budget for its CCEP. PP&L St. 17-R, Exh. DGL-2. This budget will allow PP&L to meet the stated objectives of its CCEP. Any statewide consumer education program should be developed in an orderly and logical manner. Specifically, the program details and components should be designed before the budget for statewide activities is established, not vice versa. It simply does not make sense to set a budget and then develop programs to utilize the allocated funds.

C. Customer Research

PP&L 's CCEP is based on extensive customer research. PP&L St. 17-R, p. 5-6. Based upon input from a variety of stakeholders, including the results of an independent customer research project, PP&L is revising its Customer Choice Handbook to provide education to consumers as the phase-in of full retail competition begins. Tr. 1974 (8/29/97).

D. Evaluation of Customer Education Efforts

PP&L is committed to conducting a full evaluation of its CCEP. Evaluation of PP&L's overall education efforts will be ongoing throughout the transition to retail competition. PP&L St. 17, p. 7. PP&L's research will continue to focus on what customers know and understand about choice, the best vehicles for obtaining this information, the most credible sources of information, the usage profile and related demographics. Customers already surveyed will continue to be surveyed and compared to new customers. PP&L will share this information with the Commission.

E. Separation of Education from Marketing Activities

Separation of PP&L's CCEP and its communications and marketing efforts is one of the key principles of PP&L's proposal. PP&L will not use its CCEP to market competitive business products. PP&L St. 15-R, p. 22. Its education efforts will not favor one supplier of energy or capacity over another. PP&L St. 17-R, p. 22-23. Customer choice education initiatives will be managed by the Company's Customer Services department and customer information will be managed by its Corporate Communications department. PP&L's marketing activities will seek to promote products and services through either its Delivery Services & Economic Development department or through its Generation Supply Group.

Enron witness Mr. Bowen suggests that PP&L's name should not appear on customer education communications. Enron St. 5, p. 31. As stated by Ms. Lennon: "To develop and disseminate consumer education materials and not to put the Company name on them would be deceptive. Consumers are entitled to know where any materials come from so they can ascertain for themselves whether or not to accept the messages in them." PP&L St. 17-R, p. 23.[63]

XII. Universal Service and Customer Assistance Programs

PP&L has been among the industry leaders in implementing programs to address customer and community needs, especially those of low-income customers. In 1996, the Company's annual funding level for universal service programs and energy conservation programs was over $7 million. The Company has reviewed its existing programs and concluded that it must continue its leadership role in this area. As outlined in the testimony, of Timothy R. Dahl, PP&L plans to increase its annual funding for universal service programs and energy conservation programs from a current level of $7 million to approximately $14.3 million by the year 2002. PP&L St. 16, p. 4.

Section 2802(10) of the Act provides that "the commonwealth must at a minimum, continue the protections, policies and services that now assist customers who are low-income to afford electric service." Section 2802(17) specifies that the public purpose of the programs is to be "promoted by continuing universal service and energy conservation policies, protection and

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[63] *See* Section X.D of PP&L M.B., which responds in detail to intervenors' arguments that PP&L's Generation Supply Group should not be permitted to use the "PP&L" name.

services and full recovery of such costs is to be permitted through a non-bypassable rate mechanism."

PP&L witness Dahl explained that PP&L plans to build upon its existing universal service and energy conservation programs. PP&L operates five programs that provide energy assistance to low-income customers.[64] These programs and their current level of funding are as follows:

Customer Assistance and Referral Evaluation Service ("CARES")		$260,000
Operation HELP		$795,000
Winter Relief Assistance Program (WRAP)		$3,023,300
Keep Warm Plan		$1,000,000
On Track Payment Program Pilot		$2,000,000
	Total	$7,078,300

The Company is proposing to move OnTrack from its pilot phase to a full-time program. The level of enrollment would be increased from 1,040 customers to about 10,000 customers by the year 2001. This "ramping up" of OnTrack anticipates an increase of 3,000 new participants annually. The expanded OnTrack program will target customers who have annual household income at or below 150 percent of poverty; are payment troubled[65]; and have an overdue electric bill.

There are approximately 58,000 customers who may be eligible for OnTrack based on the above characteristics. PP&L St. 16, p. 19. As a result, PP&L plans to concentrate the program on low-income customers who have a demonstrated inability to pay and may be subject to service termination. However, PP&L desires the flexibility to enroll customers who have mitigating circumstances as long as their annual household incomes do not exceed 175 percent of the federal poverty level.

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64 Mr. Dahl describes each of these programs in his direct testimony. PP&L St. 16, pp. 8-13.

65 A payment troubled customer is a customer who has missed a payment, who has contacted PP&L to negotiate a payment plan and with whom PP&L has negotiated a payment plan. Tr. 1942 (8/29/97).

A. Increased Funding

As the Commission has recognized, the challenge for the EDCs, the parties and the Commission is to set appropriate spending levels for universal service and energy conservation, in light of other spending priorities and the rate cap provisions of the Act, while maintaining funding for other aspects of safe and reliable local distribution services at least at current levels. Final Order Re: Guidelines for Universal Service and Energy Conservation Programs Made Pursuant to 66 Pa. C.S. § 2803, § 2807(17), 2804(8) and 2804(9) (entered July 11, 1997) at 3 ("Final Guidelines for Universal Service").

Although neither the Act nor the Commission's Final Guidelines for Universal Service specify a particular funding level or mandate an increase in total expenditures for universal service and energy conservation programs,[66] PP&L plans to increase its expenditures by over $7 million dollars above current funding levels. The annual level of funding for OnTrack will be expanded from $2 million to $9 million over a three-year period beginning January 1, 1999. Because PP&L will continue to solicit donations from its customers and employees, donations to Operation HELP are expected to increase annually. PP&L proposes to maintain the current level of annual funding for CARES, WRAP, and the Keep Warm Plan. PP&L St. 16, pp. 17-18.

In general, we believe the intervenor witnesses propose an unreasonable and unwarranted increase in funding levels for universal service and energy conservation programs, in some cases to over three times current levels, and expansion of the programs' eligibility criteria. *See, e.g.,* testimony of OCA witness Ms. Nancy Brockway; CEO witnesses Mr. Michael Karp, Mr. Craig Kuennen, and Mr. Geoffrey Crandall; and AARP witness Mr. Mark Cooper. These proposals are not supported by the Act or the evidentiary record in this case.

The Act has a focused purpose; that is, promoting effective competition in the area of generation. Section 2802(3) of the Act provides that " . . . it is now in the public interest to permit retail customers to obtain direct access to a competitive generation market . . ." Providing cost-effective programs for low-income customers is an important component of the Act, but certainly it is not the *raison d'être* of the legislation. The primary intent of the universal service

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[66] *See* Final Guidelines for Universal Service at 14 ("[W]e must emphasize that nothing in these guidelines mandates an increase in total expenditures directed to meet universal service and energy conservation goals. To the contrary, these guidelines emphasize improving the cost effectiveness of existing efforts by shifting expenditures from less productive efforts to more effective programs.")

provisions of the Act is to ensure that current protections for low-income consumers are maintained in a competitive generation market: "The Commonwealth must, at a minimum, continue protections, policies and services that now assist customers who are low-income to afford electric service." 66 Pa. C.S. § 2802(10). The funding levels proposed by CEO, OCA and AARP simply were not envisioned by the Act. The intent of the Act is to restructure the electric utility industry to reflect competitive forces in the marketplace, not to implement a broad expansion of customer assistance programs.

As a basis for establishing the level of need for universal service and energy conservation programs, CEO's Mr. Kuennen presents information derived from the U. S. Census about poverty rates and the number of low-income households in PP&L's service area. However, Mr. Kuennan has erred in his conclusion about the need for utility-sponsored customer assistance programs.

The 1990 U. S. Census data for the Company's service area show that approximately 177,000 PP&L customers are at or below 150 percent of the federal poverty guidelines. This guideline is the proposed eligibility standards for programs such as OnTrack and WRAP. However, most of these customers (approximately 70 percent) pay their electric bills and are not in arrears with PP&L. PP&L St. 16-R, p. 7. It would be counterintuitive for the Company to encourage customers who have been paying the full amount of their electric bills to join OnTrack and begin paying only a portion of their bills.

The Commission urged regulated utilities to implement Customer Assistance Programs ("CAPs") such as OnTrack as an adjunct to collection activities for low-income customers. OnTrack has been an effective alternative for some low-income, payment-troubled customers who are confronted with termination of service. The program has improved customers' payment patterns and has helped PP&L to avoid the costs associated with collections and regulatory intervention. It was never intended, however, to be a broad social welfare program.

OCA witness Ms. Brockway recommends that PP&L's annual funding for OnTrack and weatherization (WRAP, Keep Warm Plan) should be \$11.7 million and \$4.7 million, respectively. OCA St. 6, pp. 23, 34. Ms. Brockway's proposal represents an increase in the funding levels suggested by PP&L of 30 percent (OnTrack) and 17.5 percent (WRAP and Keep Warm Plan). AARP witness Mr. Cooper has stated that deep discounts should be made available to all low-income households. AARP St. 1, pp. 25-26. The cost of extending OnTrack credits to all of PP&L's low-income customers would be prohibitive. The average OnTrack credit is $50 per month, or $600 annually. PP&L St. 16-R, p. 9. The cost of extending the credits, as Mr. Cooper suggests, would exceed $106 million annually (177,000 x $600). For the reasons described above, the increased funding levels recommended by these parties should be rejected.

B. Availability of Universal Service and Customer Assistance Programs

CEO witness Mr. Kuennen recommends that PP&L target 40 percent of low-income households (specifically, 71,000 customers) for participation in OnTrack.[67] CEO St. 1, p. 22. OCA witness Ms. Brockway suggests that PP&L should serve 18,500 customers in OnTrack. OCA St. 6, p. 30. These proposals present three significant problems: 1) it would be impractical to effectively identify, interview, and enroll tens of thousands of customers; 2) the costs would be prohibitive; and 3) good-paying customers would be encouraged not to pay under the CEO's proposal.

Mr. Kuennan and Ms. Brockway also advocate increased funding levels for the baseload program under WRAP. As acknowledged by Ms. Brockway, each utility should tailor its energy conservation programs to address the conditions in its own service area. Tr. 2042 (8/29/97). Given that PP&L has the highest electric heat saturation rate of the eight major Pennsylvania electric utilities, PP&L Cr. Exam. Exh. 12, PP&L has properly chosen to focus its weatherization activities on electric heat customers.[68]

C. Allocation of Universal Service Program Costs

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[67] Mr. Kuennen projects that 71,000 customers could be enrolled in OnTrack at an annual cost of about $23 million. This is a gross underestimation of the annual cost, which the Company estimates would be at least $53 million annually. The cost may even be higher because some of these customers would enter the program with overdue balances that would be forgiven if they made their monthly payments. The average revenue shortfall (i.e., the difference between the actual bill and the required OnTrack payment) for an OnTrack customer is $600. If 71,000 customers were enrolled in OnTrack, the annual revenue shortfall cost alone would be approximately $42.6 million (71,000 x $600).

[68] This focus is also consistent with the Commission's low income usage reduction regulations, 69 Pa. Code § 58.10, which require utilities to place the highest priority on those eligible customers with the largest usage and greatest opportunities for bill reductions relative to the cost of providing program services.

A number of intervenors recommend a kWh assessment of universal service program costs on all customer classes. As explained more fully in Section IX.D of PP&L's M.B., PP&L instead proposes to allocate its universal service charges on a per customer basis. PP&L's approach is consistent with the Commission's Final Guidelines for Universal Service, in which the Commission found that a kWh assessment would place a disproportionate responsibility for funding universal service and energy conservation programs on high volume users and is inconsistent with rate treatments for these programs in recent base rate cases. Final Guidelines at 20.

D. Other Universal Service and Customer Assistance Program Recommendations

1. "Transfer" of Uncollectible Accounts

CEO witness Mr. Kuennan and OCA witness Ms. Brockway suggest that PP&L's current level of write-offs and credit and collection expenses associated with non-OnTrack low-income customers could be "transferred" to fund an expanded OnTrack Program rather than booking write-offs and credit and collection expenses associated with these amounts, in essence reducing its billings to these customers. CEO St. 1, p, 26; OCA St. 6, p. 26. Ms. Brockway acknowledges that this approach would not improve PP&L's bottom line, yet she asserts that even if no associated benefits of lowered collection costs or improved dollar payment amounts were realized by PP&L, the customer would benefit from this transfer from a delinquent debt posture to one of a reasonable opportunity to make complete payments.

As Mr. Dahl pointed out, Ms. Brockway's proposal should be rejected because it is based on the key false assumption that low-income customers do not pay any portion of their bills. To the contrary, however, PP&L's experience shows that low-income customers, even those that are payment-troubled, do often pay some amount toward their bills. For example, PP&L evaluated approximately 1,000 very low-income customers (at or below 110% of the federal poverty guidelines) and determined that even those customers pay PP&L six or seven times per year. Tr. 1948 (8/29/97).

2. Customer Choice for OnTrack Customers

PP&L supports the OCA's recommendation to allow OnTrack customers to choose Alternative Suppliers; however, this participation must be subject to three important conditions. First, OnTrack participants who select an Alternative Supplier would be required to receive a single bill from PP&L. Second, as a condition of serving OnTrack customers, Alternative Suppliers would agree to discount the energy portion of the supply bill by a percentage equal to the overall percentage reduction established pursuant to the OnTrack program. Third, the Alternative Suppliers would agree to absorb the supply portion of the revenue shortfall that is written off monthly for OnTrack customers.

A key objective of OnTrack is to encourage and develop good payment habits among customers. This objective could be best accomplished by offering one bill to OnTrack customers who choose an Alternative Supplier. PP&L believes so strongly in this concept that it greatly simplified the OnTrack bill to encourage regular payments. A combined bill would streamline administrative procedures for the OnTrack agencies and reduce confusion for customers who may have questions. Requiring these customers to write two checks monthly -- one to PP&L and one to the Alternative Supplier -- would add unnecessary complexity to the program.

PP&L's average monthly electric bill for low-income, payment-troubled customers is about $88, and the average monthly electric bill for OnTrack customers is $47. In other words, the Company provides a monthly bill reduction of $41, or 53 percent. This revenue shortfall is written off monthly. PP&L St. 16-R, p. 22. PP&L recommends that Alternative Suppliers provide a pro rata reduction in energy supply charges to those OnTrack customers who choose an Alternative Supplier. Without such a pro rata reduction, the amount of the monthly bill reduction could reduce the transmission and distribution portion of the customer's bill to less than zero.

PP&L also believes that Alternative Suppliers should share in the costs of the revenue shortfall associated with OnTrack customers. Generation accounts for approximately 25 percent of the bill, and using the above example of the $41 revenue shortfall for the average OnTrack customer, an Alternative Supplier would be responsible for $10.25 of the write-off. The remaining $30.75 would be assigned to PP&L. Because the revenue shortfall includes some generation charges, it is fair for Alternative Suppliers to assume responsibility for the portion of their the revenue shortfall. PP&L's proposal would treat both PP&L and the Alternative Supplier on the same basis while satisfying the Act's objective of providing choice to all customers in Pennsylvania.

XIII. ENVIRONMENTAL ISSUES

A. Disclosure of Fuel Mix and Waste Discharge Information

Environmentalists witness Bruce E. Biewald proposes that the Commission require all retail electricity suppliers selling in Pennsylvania to disclose their fuel mix and key air and other waste emissions to consumers in the form of a label and that the tracking of transactions to support disclosure and labeling should be done by the PJM Independent System Operator ("ISO"). Environmentalists' St. 2, p. 5. OCA witness Barbara Alexander also advocates fuel mix disclosure. OCA St. 5, pp. 29-30.

Mr. Biewald's proposal goes beyond the Commission's recently-proposed rules on Customer Information Disclosure for Electricity Providers Docket No. L-00970126, which propose that suppliers provide a written disclosure statement of energy sources, and, if the supplier cannot identify the energy source of its supply (if, for example, the supply is purchased from a power pool), disclosure of the average energy mix from the relevant market, including an identification of that market by name. The source of supply mix must be provided to customers upon request, upon entering into a sales agreement and whenever a significant change occurs in the terms of service. The proposed rules do not require the disclosure of environmental attributes other than fuel mix. The Commission's rulemaking is a more workable system than the one proposed by Mr. Biewald that satisfies the needs of responsible disclosure. *See* PP&L St.10-R, p. 20 Moreover, we believe as argued by PP&L, that this Commission lacks the power to require the PJM ISO to adopt Mr. Biewald's proposal.

The Environmentalists witness Mr. Schoengold asserts that PP&L has not proposed to improve significantly the environmental performance of its existing generating plants. Environmentalists' St. 1, p. 36. Therefore Schoengold argues, PP&L's generating plants will be able to compete unfairly in a competitive market where builders of new power plants will be required to meet stringent emissions standards.

Consequently Schoengold recommends that the Commission require that all power purchased in Pennsylvania come from plants meeting the latest environmental standards, Environmentalists' St. 1, p. 37. Mr. Schoengold notes that other states have enacted similar regulations based on their right to protect the health and welfare of their citizens. We recommend that this proposal be rejected for the following reasons.

First, although the Commission retains broad authority to regulate utility service, facility and rate issues, it is the Pennsylvania Department of Environmental Protection and the U.S. Environmental Protection Agency that have the broad authority to implement and administer programs for the protection of the environment, including rules relating to air emissions.[69] *See, e.g., Country Place Waste Treatment Co., Inc. v. Pa. P.U.C.*, 654 A.2d 72, 75-76 (Pa. Commonwealth Ct. 1995) (the Pennsylvania Utility Code fails to directly or indirectly grant the Commission the authority to regulate air pollution produced by public utilities); *Rovin v. Pa. P.U.C.*, 502 A.2d 785 (Pa. Commonwealth Ct. 1986) (Department of Environmental Protection, not the Commission, has jurisdiction over complaint alleging water quality issues).

Although § 2802(21) of the Act authorizes the Commission to work with state environmental regulators and to support certain changes to federal law and regulation on the issue of air emissions, the Act does not extend rate regulation authority for emission policy above and beyond compliance with current law and regulation from environmental regulators. Tr. 830 (8/19/97).

Second, 48% of the capital expenditures necessary to operate PP&L's facilities for the period 1997 through 2001 will be incurred to ensure environmental compliance. PP&L St. 10-R, pp. 37-38.

Third, there is no evidence to support the claim that existing plants enjoy a competitive advantage under the current environmental regulatory scheme. PP&L St. 10-R, pp. 39-40.

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[69] For example, EPA has proposed a rule requiring certain Northeast and Midwest states to revise their air pollution control plans to mitigate the transport of ozone across state lines. *Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone*, 62 Fed. Reg. 60318 (Nov. 7, 1997). EPA hopes to issue a final rule in September 1998. The DEP administers the EPA's air quality regulations through the Pennsylvania State Implementation Plan and has concurrent authority to impose penalties for noncompliance.

B. Renewables Pilot Program

OCA witness Ms. Brockway's suggests that PP&L provide funding of $700,000 for photovoltaic and active solar water heating pilots. Neither the Act nor the Commission's Final Guidelines for Universal Service mandate such pilot programs.[70]

Developing, implementing, and evaluating these pilots would be time consuming and expensive for the level of benefits received. As described in PP&L witness Mr. Dahl's testimony, because of the long payback period, the complexity of the systems, the difficulty of installation and maintenance, the likely resistance from landlords, and the Commission's direction in its final order, we recommend that the OCA's recommendation to fund renewable energy pilots be rejected.

XIV. PUBLIC INPUT HEARING CONCERNS

As we stated earlier, thirteen (13) public input hearings were held during the weeks of May 30, 1997 and September 2, 1997. Public input hearings were held in Allentown (June 2), Bethlehem (June 2 and September 3), Harrisburg (May 30 and September 3), Hazleton (June 4), Lancaster (May 30 and September 2), Pottsville (June 4), Scranton (June 3 and September 4), Williamsport (June 5), and Wilkes-Barre (June 3). A total of 75 persons testified at the public input hearings.

It is difficult to recapitulate all the concerns voiced by the customers of PP&L throughout its territory. However, at the hearing in Bethlehem there was one witness who expressed volumes in one quiet statement. We believe her statement expresses the concerns of many.

Nancy Tate, 23 Riegelsville, Pennsylvania, Post Office Box 344, an organizer and peace worker since 1965, summed up the range of issues which we heard at the majority of public input hearings. Here concern about a whole range of "justice" issues. Ms. Tate spoke as a PP&L customer representing many of over 600 members of LEPOCO, which stands for the Lehigh

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70 The Commission's Final Guidelines for Universal Service expressly provide that: "Although we believe that research and development are important, we will not direct that universal service and energy conservation funds be spent for research and development. Unlike the California legislature that specifically provided funds for research and development, the Commonwealth's Act gives no direction for such expenditures." Final Guidelines for Universal Service at 6.

Pocono Committee of Concern (also customers) and has worked locally in the Lehigh Valley for peace and justice for over 30 years.

"Unfortunately, the issues around deregulation and competition and electric generation have not received adequate public attention and debate. That was true as the enabling law was rushed through the Pennsylvania Legislature, and is again true as public opinion is being sought for PP&L's restructuring proposal. Most of us have only a few clues about what this will mean, and many probably have no idea that drastic changes are coming in the way electricity is provided in this state. While many of the powerful in our country currently sing unquestioning praises for competition and no government interference in business, there are also some of us who believe that the regulations that have been placed on businesses like electric utilities came about to provide fair and equitable access to this service and to protect the average consumer. Indeed, that system has not always served that average consumer. Just witness the development of nuclear power, in my opinion. But moving to a system that serves mainly large businesses cannot be seen as an improvement. Dare I say, more public control, not less, is the direction we should be moving. But given our current situation, I have several questions and concerns that I hope the Pennsylvania Public Utility Commission will address as they review the PP&L proposal. What protections will there be to prevent customers from harassing calls and solicitations that have accompanied the deregulation of telephone service? There are many of us who feel there should be much more to life than shopping, whether that be at a mall or through the phone calls offering you the best deal on long distance rates or electric rates. What unbiased review will be available to the consumer to assist in making an intelligent, wise choice in electric service? For starters, such information should weigh environmental benefits or hazards of such service, how fair the service will be to the poorest in our community, what special deals are being cut for the richest. Are the workers of the provider being paid a living wage? Do they have union representation? Are their rates fair and comparable? There are probably many other issues that will be important for the consumer to make a truly intelligent choice. Many of us feel deregulation and competition in telephone service has really meant higher rates for the average consumer. What will be done to prevent this eventuality as electric providers establish duplicate marketing and production networks? What protections will be given for adequate, affordable service to the poor in our communities? What protection will be given to assure that heat is available to everyone during the winter months and is not cut off unfairly? What will you do to assure that the workers and employees of other electric providers besides PP&L have union representation and protection like the present workers at PP&L? How will you prevent the profits of *competing* providers from being made at the expense of lower wages for the workers? How will you prevent PP&L's profits from being made from layoffs of their workers? What protection will you give to assure that the small and environmentally friendly producer of power has a good opportunity to be among the electric generators? What measures will be taken to guarantee that this new system encourages rather than discourages energy conservation? And what protection is there that large powercustomers don't get savings at the expense of the average electric consumer? Finally, I believe it is grossly unfair to the average consumer to be asked to pay for the decision by PP&L management and stockholders to build the nuclear power plants that are located near Berwick, Pennsylvania. It was an unsafe and uneconomical decision at the time it was made, and remains so. Indeed, to allow them to bill the average consumer for this expense while these plants continue operating, producing ever more nuclear waste, is doubly hazardous. These stranded costs should be borne by those who were the advocates of nuclear power, as I have said, management and the stockholders.These are the many points that I want to raise, and thank you for the opportunity to do so." *TR*. 176-184 (June 2, 1997).

XV. CONCLUSIONS OF LAW

I. That the Pennsylvania Public Utility Commission properly has jurisdiction over PP&L, Inc.'s ("PP&L") Restructuring Plan filing at Docket No. R-00973954;

II. That PP&L's Restructuring Plan as modified herein is fully consistent with the requirements and standards of Section 2804 of the Electricity Generation Customer Choice and Competition Act ("Act"), 66 Pa. C.S. §2804, in that it, inter alia:

A. Will ensure the continuation of safe and reliable electric service to PP&L's customers;

B. Is consistent with the implementation schedule set forth in Section 2806 of the Act, 66 Pa. C.S. §2806;

C. Complies with the rate caps set forth in Section 2804(4) of the Act, 66 Pa. C.S. §2804(4);

D. Ensures that PP&L will provide transmission and distribution service to all retail electric customers in its service territory and to all alternative generation suppliers, either affiliated or nonaffiliated, on rates, terms of access and conditions that are comparable to PP&L's own use of its system;

E. Ensures that PP&L's restructuring does not unreasonably discriminate against one customer class to the benefit of another;

F. Ensures that universal service and energy conservation policies, activities and services are appropriately funded and available in PP&L's territory;

G. Provides for a competitive transition charge for the recovery of transition or stranded costs in accordance with Section 2808 of the Act, 66 Pa. C.S. §2808;

H. Ensures an orderly transition to a competitive generation market that protects electric system reliability, is fair to customers and provides PP&L and its investors with a fair opportunity to fully recover its just and reasonable stranded costs;

III. That PP&L's Restructuring Plan as modified herein is fully consistent with the requirements of Section 2807 of the Act, 66 Pa. C.S. §2807, regarding the obligations applicable to electric distribution companies;

IV. That PP&L's claimed stranded or transition costs are not known, measurable, just and reasonable in accordance with all requirements of the Act, including Sections 2803 and 2808 (66 Pa. C.S. §§2803, 2808); and

V. That PP&L's Restructuring Plan does not fully comply with the requirements of Section 2810 of the Act, 66 Pa. C.S. §2810, regarding revenue-neutral reconciliation.

XVI. RECOMMENDED ORDER

THEREFORE,

IT IS ORDERED:

1. That the Application of Pennsylvania Power & Light Company for approval of its restructuring plan pursuant to Section 2806(d) of the Public Utility Code, 66 Pa. C.S. 2806(d), filed on April 1, 1997 and docketed with the Pennsylvania Public Utility Commission at No. R-00973954, is hereby adopted as herein modified.

2. That Pennsylvania Power & Light Company shall remain the provider of last resort consistent with the determinations made herein and the requirements of 66 Pa. C.S. 2802(16).

3. That Pennsylvania Power & Light Company shall phase-in direct access to alternative generation suppliers in the manner specified in this decision, pursuant to the following schedule:

a. 33 % of the peak load of each customer class shall have the opportunity for direct access as of January 1, 1999;

b. 66% of the peak load of each customer class shall have direct access as of January 1, 2000;

c. All customers shall have direct access as of January 1, 2001.

4. That the competitive transition charge may be collected from January 1, 1999 until December 31, 2005 or for a shorter period of time as the Commission deems appropriate.

5. That the competitive transition charge authorized in the preceding ordering paragraph is subject to the following requirements:

a. The competitive transition charge may be collected from January 1, 1999 until December 31, 2005.

b. The competitive transition charge shall be calculated and applied consistent with the directives contained herein.

c. The competitive transition charge shall be reconciled and may be modified on an annual basis as required by 66 Pa. C.S. 2808(f).

d.. The competitive transition charge shall be calculated in a manner recognizing monthly receipt of competitive transition charges revenues.

6. That Pennsylvania Power & Light Company shall modify its transmission and distribution revenue requirement and rate structure to incorporate the adjustments, including cost allocation method, as directed herein.

7. That Pennsylvania Power & Light Company continue to provide service to existing customers through existing tariffs throughout the transition period, and all special contracts shall remain in force, except as modified herein.

8. That Pennsylvania Power & Light Company comply with the determinations contained herein relating to customer billing and metering and that Pennsylvania Power & Light Company reflect this action in its compliance filing.

9. That, pending the outcome of the Commission's rulemaking proceeding on a generic Code of Conduct, Pennsylvania Power & Light Company shall modify its proposed Code of Conduct as herein directed.

10. That Pennsylvania Power & Light Company's proposed Universal Service and Energy Conservation Programs are approved as modified herein.

11. That Pennsylvania Power & Light Company participate in the state-wide consumer education initiative,which the Commission established in its decision in the Application of PECO Energy Company at Docket No. P-00973953 (Opinion and Order entered December 23, 1997); that in its compliance filing, Pennsylvania Power & Light Company include a comprehensive plan for consumer education with an associated budget for both mass media and local educational efforts and set forth its proposals for its role in consumer education; and that Pennsylvania Power & Light Company recover the costs of its consumer education program from its ratepayers.

12. That Pennsylvania Power & Light Company shall, within twenty (20) days of entry of the Commission's final Opinion and Order at this docket, submit a compliance filing that incorporates all of the conclusions and directives contained in this Recommended Decision, including, but not limited to:

a. For each tariff class or schedule, the compliance filing shall:

i identify the unbundled chargesfor generation, transmission and distribution service;

ii. identify the CTC, calculated to recover the authorized principal amount, consistent with the allocation methodology, collection period, monthly amortization, total sales, and return adopted herein; and

iii identify all other adjustments necessary to the terms and conditions of service to reflect a competitive generation market as provided herein.

b. Each tariff class or schedule shall reallocate Administrative and General expense as provided herein.

13. That Pennsylvania Power & Light Company serve a copy of its compliance filing on all parties to this proceeding on the same date that it is filed with the Commission.

14. That all parties to this proceeding may file written comments concerning non-compliance with the Commission's Opinion and Order within seven (7) days after the filing of Pennsylvania Power & Light Company's compliance filing.

15. That, in addition to the specific requirements contained in the foregoing ordering paragraphs,Pennsylvania Power & Light Company shall comply with all other directives contained in this Recommended Decision.

16. That the complaints filed by the Office of Consumer Advocate (OCA) , PP&L Industrial Customer Alliance (PPLICA), Office of Small Business Advocate (OSBA), Office of Trial Staff (OTS), Allegheny Power, American Association of Retired Persons (AARP), Commission on Economic Opportunity (CEO), Delmarva Power & Light, Enron Power Marketing Inc.(Enron), Environmentalists, Local 1600, International Brotherhood of Electric Workers (IBEW), Eric Epstein, Gilberton Power, Mid-Atlantic Power Supply Association (MAPSA), New Energy Ventures (NEV), Pennsylvania Petroleum Association (PPA),), Schuylkill Energy Resources (SER), and United States Department of Defense;Together with, the interventions of the following are inactive parties in Docket No R-00973954: Allegheny Electric Cooperative, American Energy Solutions, Anthracite Regional Power Producers (ARIPPA), Bethlehem Steel, Center for Energy and Economic Development (CEED), Duke Energy Trading Marketing, Dupont Power Marketing, Electric Clearinghouse Inc., ERI Services Inc., GPU Energy, Kraft Foods, Noram Energy Management, PECO Energy Company, Pennsylvania Association of Plumbing Heating & Cooling Contractors (PAPHCC), Pennsylvania Electric Consumers Council, PP&L Rate Payers Association, and Pennsylvania Retailers Association, Vastar Power

Marketing. be and are hereby granted or denied to the extent set forth in this Recommended Decision.

Dated: April 1, 1998

GEORGE M KASHI
Administrative Law Judge

STRATEGIC ENERGY

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MICHAEL SWIDER
MANAGER, REGULATORY AFFAIRS
202-669-1602

VIA E-MAIL

RE: Developing Consensus Recommendations on Stranded Costs

TO: Susan Larsen, Virginia State Corporation Commission

CC: Stranded Cost Working Group

FR: Michael Swider, Strategic Energy LLC

Date: 8 May 2003

Strategic Energy supports the proposal submitted by the Virginia Committee for Fair Utility Rates (VCFUR) as being the best methodology for determining whether the recovery of stranded costs in the wires charge and the capped rate "has resulted or is likely to result in the overrecovery of underrecovery of just and reasonable net stranded costs" as required in the Restructuring Act (§56-595.) A thorough review of the amount of net stranded costs, and the amount of stranded costs that have been and will be recovered through the wires charge and the capped rate is an effective methodology that will provide the data necessary to determine when and where underrecovery ends and overrecovery begins.

The Dominion Virginia Power ("DVP") proposal does not provide a complete methodology for determining net stranded costs. First, DVP proposes a flawed mechanism for determining the market value of assets by relying on the wires charge methodology. The wires charge methodology, fundamentally, uses spot market prices to set a proxy value for market revenues from a utility's generation assets. However, the true market value of any generation asset is based not just on the spot market-clearing price relative to its operating costs. A full and proper valuation must include the option value of the asset that is created by the market[1]. Second, DVP proposes to assess its "actual 'above-market' or 'potential' stranded cost exposure" but not its stranded benefits collected or accrued under the capped rates. The Act clearly requires that "net" stranded costs be monitored, which requires any stranded benefits be added to the equation.

The Staff "earnings test" approach is workable, but incomplete. To complete the evaluation of net stranded cost the earnings test would have to consider not only current years revenues ("actual stranded costs") but an estimate of the discounted value of future years revenues. For example, a utility may be front-loaded with out-of-market power purchase agreements, but be back loaded with low-cost generation. Looking at only the front years would therefore grossly

[1] For example, an asset owner with a flexible unit can sell into the bilateral market and maximize the option value of the unit by running the unit (covering its short position) only when spot price exceeds the contract price.

underestimate the utility's stranded benefits. Estimates of future rates are complex and rely on assumptions. However, these types of studies are done every day for every type of asset that is bought, sold and built.

It is not impossible to develop a reasonable estimate of long-run net stranded costs and compare those to the amount of stranded cost recover that has already occurred and will occur during the capped-rate period to determine whether there will be underrecovery or overrecovery of net stranded costs. Performing this type of analysis is the only way that consumers will be sure that the stranded cost recovery period will not extend beyond that which is reasonable.

In conclusion, Strategic Energy believes that the SCC's report to the LTTF should include a recommendation to perform a study to compare the foregone regulated revenues to the long-run market revenues as described in the VCFUR proposal. The result of the study should be used to determine whether those utilities that currently charge a wires charge should cease collecting this charge prior to July 1, 2007 for the purpose of advancing to goals of competition and economic development as required in the Act (§56-596).

-mjs.

Ms. Susan Larsen
Deputy Director, Public Utility Accounting
Virginia State Corporation Commission
Tyler Building
1300 E. Main Street
Richmond Virginia, 23219

Dear Ms. Larsen,

At the last meeting of the Virginia Stranded Cost Working Group, Commission Staff requested comments on three proposals for dealing with the issue of over or under recovery of just and reasonable net stranded costs. Pepco Energy Services firmly believes that to the extent that stranded costs exist for utilities in Virginia, they are a product of the enactment of Virginia's Electric Utility Restructuring Act ("Act"), that they are measurable, and that over or under recovery from capped rates and wires charges should be measured against these costs. Pepco Energy Services supports the proposal presented by Ed Petrini for the Virginia Committee for Fair Utility Rates ("Committee"). Pepco Energy Services also believes that the earnings test that is part of the Staff's proposal is consistent with the Committee's proposal but believes that the Staff's concept of actual vs. potential stranded costs is not consistent with the Act. Further, Pepco Energy Services does not believe that Dominion Virginia Power's clarification to its proposal overcomes the flaws within that proposal.

Pepco Energy Services urges the adoption of the methodology put forth by the Committee in its proposal. This is supported by our comments below.

Virginia Committee for Fair Utility Rates Proposal

At the April 29th meeting of the Stranded Cost Working Group, Ed Petrini, representing the Virginia Committee for Fair Utility Rates ("Committee"), distributed a general overview regarding a proposal for measuring stranded costs as well as determining whether or not utilities have been over or under recovering these costs through capped rates and wires charges. Pepco Energy Services supports this proposal and believes that it is a reasonable framework for defining stranded costs and for measuring the recovery of those costs.

First, the Committee's proposal lays out the foundation for why this approach is appropriate. Section 56-584 of Virginia's Electric Utility Restructuring Act ("Act") provides that:

> "each utility shall only recover its just and reasonable net stranded costs through either capped rates as provided in § 56-582 or wires charges as provided in § 56-583."

Capped rates and wires charges are the two and only two means by which a utility may recover just and reasonable net stranded costs. The Act does not define stranded costs or just and reasonable net stranded costs. The Act only recognizes that these costs may exist and to the extent they do exist provides a framework for recovery.

Pepco Energy Services advocates the position that it is the creation of the right allowing customers to choose alternative suppliers that establishes stranded costs not the actual act of customers switching. Prior to the Act, utilities in Virginia had a regulatory franchise to provide generation services to customers within their respective service territories. The Act took away that exclusive franchise in order to allow the higher good of competitive choice. The removal of the franchise in favor of allowing customers to choose created a change in the expected return of and on the generating assets that each utility had invested in. The difference in the cost recovery from those generation assets that were expected under the regulated franchise and the cost recovery under competition are stranded costs. The Committee's proposal is consistent with this approach to stranded costs.

Section 56-595 of the Act establishes the Legislative Transition Task Force ("Task Force"). As part of its responsibilities, the Task Force is to monitor

> "whether the recovery of stranded costs, as provided in §56-584, has resulted in the overrecovery or underrecovery of just and reasonable net stranded costs" (§ 56-595 C (iii)).

Pepco Energy Services believes that the most reasonable reading of the Act is that the General Assembly expected that the Task Force "with the assistance of the Commission, the Office of the Attorney General, incumbent electric utilities, suppliers, and retail customers" (§56-595.C (iii)) would define just and reasonable net stranded costs, determine a methodology for measuring those costs, and "annually report to the Governor and each session of the General Assembly" (§ 56-595 C (v)). It is impractical to measure the over or under recovery of just and reasonable net stranded costs through capped rates and wires charges without having measured just and reasonable net stranded costs in the first instance. Pepco Energy Services supports the Committee's proposal as being completely consistent with the Act and as an acceptable framework for the calculation of both just and reasonable net stranded costs and their recovery under the Act. Pepco Energy Services also supports the Committee's proposal to use the annual information filings (AIFs) required of incumbent electric utilities as the basis for calculating a utility's historical cost of providing service as well as any revenues in excess of those that may be available for recovering stranded costs.

There are still several details that are not included in the Committee's proposal. The most prominent of those is the point at which just and reasonable stranded costs should be calculated. The three most logical points would be (i) July 1, 1999, the date that the Act was enacted, (ii) January 1, 2002, the date that customer choice was made available in Virginia, or (iii) some time this year. The first two dates represent in slightly different ways the end of the utilities' generation franchise, specific points against which to measure the change in value of their generation assets. The third date may serve as a matter of convenience. Since some may argue that it is too difficult to determine historical forward pricing curves, then an alternative would be to measure stranded costs from the current period. Pepco Energy Services has not taken a position on which is the most appropriate date of measurement except that the company would oppose moving the measurement date beyond 2003. In order to begin the process of measuring over or under recovery, stranded costs must be measured now. Moving the date out would create a moving target against which to measure.

Staff Proposal

Staff presented a proposal titled "Stranded Costs – An Accounting Perspective". The basis of this proposal is the use of an earnings test as the basis to determine the over or under recovery of stranded costs. Staff, like the Committee in its proposal, recommends the use of the AIFs as the source for data for the earnings test. The Committee and Staff proposals both use an earnings test and both use the AIF as the source for data for that test. Pepco Energy Services fully supports this approach. However, Pepco Energy Service cannot support the application of this approach by Staff.

As part of its proposal Staff also provided definitions. Among these are "actual stranded costs" and "potential stranded costs". Staff defines actual stranded cost "as the underrecovery of just and reasonable generation costs in a competitive environment." In general Pepco Energy Services agrees with this definition, however, Staff goes further to state: "Actual stranded costs would occur after the termination of capped rates and wires charges if actual generation costs exceed market prices."

As stated earlier, Pepco Energy Services asserts that it is the end of the utility monopoly franchise on generation services that creates the stranded costs not the end to capped rates and wires charges. Staff takes the position that stranded costs are to be mitigated using capped rates and wires charges but not measured until the end of the capped rate period. This is not consistent with the concept of monitoring over or under recovery during the period as required by the Act.

Staff argues for the use of potential stranded costs, defined as the annual stranded cost exposure during the capped rate period, as the mark against which to measure stranded cost recovery. One significant flaw with this approach is that to calculate potential stranded costs under the Staff model, there is an assumption that everyone is paying market based rates for electricity. Although customers are currently allowed to choose in Virginia, there are no effective choices to make for standard electricity, therefore, there are no market based rates from which to make this determination.

Pepco Energy Services believes that Staff's interpretation of actual and potential stranded costs as presented in its proposal is inconsistent with the Act. Further the use of potential stranded costs will: (a) impair the functioning of a competitive market by creating price uncertainty, and (b) necessitate further complication by making it a certainty that there will be either over or under recovery, and rates will have to be developed to address this eventuality.

<u>Dominion Virginia Power Proposal</u>

Dominion Virginia Power ("DVP") provided a proposal, which was subsequently modified for clarification purposes. These clarifying statements have done nothing to overcome the flaws inherent within this proposal. The DVP proposal calls for four (4) reports. The first report would be to simply calculate whether the revenues collected from the wires charge, which is based on forecasted prices, where higher or lower than forecasted. This proposal is flawed in that it does not measure the over or under recovery of stranded costs but merely compares actual versus forecasted prices. There is no defining of stranded costs or how the wires charges are used to offset those costs.

The second report would track "potential stranded cost exposure" by comparing revenues under capped rates versus a calculation of revenues under market prices. Market prices are defined as the same prices used in the calculation of wires charges. DVP appears to be advocating the use of wholesale prices as a proxy for retail market prices. This would have the effect of significantly overstating stranded costs. This proposal also uses capped rates as the basis from which to measure potential stranded cost exposure rather than rate of return basis. Since the Act contemplates cost recovery for stranded costs from both wires charges and capped rates, this will also cause stranded costs to be overstated.

The third and fourth reports would detail expenditures by each utility that would mitigate and add to stranded costs respectively. Pepco Energy Services contends that stranded costs should be calculated first. Pepco Energy Services would concur that cost mitigation measures should be tracked and reported but would argue that this does not mitigate the need to calculate total stranded costs, costs that were created as a byproduct of ending the generation franchise of the utility.

Recommendations for Legislative or Administrative Action

LTTF requested action #9 reads: "Include in its reports to the LTTF any recommendations for legislative or administrative action that the Commission, the work group, or both, determine to be appropriate in order to address any overrecovery or underrecovery of just and reasonable net stranded costs." As shown earlier, the Act clearly contemplates capped rates and wires charges as the only means to recover just and reasonable net stranded costs. It is therefore imperative to measure total stranded costs immediately, measure the costs recovered to date through capped rates and wires charges, and examine the expected rate of recovery through the end of the capped rate period. If it becomes apparent that a utility has or, during the capped rate period, will significantly over or under recover its just and reasonable net stranded costs, then action should be taken to the extent possible to adjust for this over or under recovery. If a utility is significantly over recovering stranded costs, then Pepco Energy Services would advocate legislative changes to the method for calculating the charges for the recovery of stranded costs that would have the effect of reducing or eliminating the wires charges. This would have the effect of reducing recovery and stimulating competition. On the other hand, if the utility is significantly under recovering stranded costs, then the Commission should consider whether capped generation rates should be raised.

Sincerely,

A. Glenn Simpson
Vice President
Pepco Energy Services, Inc.

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May 7, 2003

Via Electronic Delivery Only

Susan D. Larsen, Deputy Director
Division of Public Utility Accounting
State Corporation Commission
1300 East Main Street
Richmond, VA 23218-1197

Re: *Commonwealth of Virginia, ex rel. State Corporation Commission In the Matter of Developing Consensus Recommendations on Stranded Costs Case No. PUE-2003-00062*

Dear Ms. Larsen:

Here are the comments of Washington Gas Energy Services (WES) based on the four questions raised at the April 29, 2003 meeting of the Stranded Costs Work Group. We thank the Commission for moderating the meetings and look forward to our continued involvement in the process of an orderly development of a fully competitive electricity market in Virginia

Q1) LTTF requested action #9 reads: "Include in its reports to the LTTF any recommendations for legislative or administrative action that the Commission, the work group, or both, determine to be appropriate in order to address any overrecovery or underrecovery of just and reasonable net stranded costs." Please discuss whether the definitions and/or methodologies discussed by the work group might require any action as contemplated by Requested Action #9. Discuss what action may be necessary, the timing of that action, and why it is necessary.

WGES Answer: 1) LTTF Requested Action #9

The definitions and/or methodologies discussed by the Stranded Costs Work Group would not require any action by the LTTF as contemplated by Requested Action #9 in Phase I. However, in Phase II, the Commission could recommend a true-up process to the LTTF for any overrecovery or underrecovery of just and reasonable net stranded costs to be conducted at least annually. It should be made clear that the cessation of stranded costs recovery is 2007.

Another clarifying point worth making is that stranded costs recovery in Virginia commenced on the same day that capped rates were effective for each utility company. The utility-specific effective date for capped rate recovery is superior to either the effective date for

Choice in each service territory or when the Restructuring Act was enacted because stranded costs are deemed to be recovered in capped rates or wires charges. Therefore, the recovery date is the same with the derivation of revenues from capped rates and wires charges. It is not unreasonable to expect that each utility considered the calculus of stranded costs and the recovery mechanism prior to agreeing to the restructuring plan. We urge Staff not to recommend the separation of stranded costs recovery date from the initiation of capped rates.

Q2) Comments Regarding the Stranded Costs Proposal Put Forth by Ed Petrini.

Answer: 2) Mr. Petrini's proposal offers a direct approach to the calculation of stranded costs. It is not unlike the Asset Valuation Model that would meet the request of the LTTF. Therefore, WGES finds the suggestion acceptable.

Q3) Comments on the Staff Proposal Discussed at the 4/29/2003 Meeting.

Answer: 3) Although Staff's proposal was presented as complimentary to the Asset Valuation Model, WGES could neither support a method that fails to compute stranded costs nor a new recovery mechanism outside capped rates and wires charges. It would also not be appropriate to assume that actual stranded costs would occur after the expiration of any recovery mechanism as the accounting approach would entail. The public interest and that of the orderly development of competition in the Virginia electricity market would be well served if potential and actual stranded costs considerations are concluded within the transition period without further meddling with "cost-based unbundled generation rates (at a fair return)" as the model also contemplates. The latter would seem an unacceptable cost-of-service scenario to deal with stranded costs. Based on the aforementioned, WGES is not in favor of the accounting perspective presented by Staff on April 29, 2003.

Q4) Comments on the Clarifications of Dominion's Proposal.

Answer: 4) WGES is not persuaded that Dominion's approach properly deals with over/under recovery of stranded costs through revenues from wires charges only. Further, the methodology proffered would not lead to the calculation of stranded costs for each utility company as intended by the LTTF, further refinements and clarifications included. Therefore, we remain opposed to the Dominion's proposal.

Respectfully submitted,

Ransome Owan

Ransome E. Owan, Ph.D.
Director, Regulatory and External Affairs

National Energy Marketers Association

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

COMMONWEALTH OF VIRGINIA, ex rel.

STATE CORPORATION COMMISSION

In the Matter of Developing Consensus Recommendations on Stranded Costs — **Case No. PUE-2003-00062**

COMMENTS OF THE NATIONAL ENERGY MARKETERS ASSOCITION

The National Energy Marketers Association hereby submits comments on the stranded cost proposals presented in the April 29, 2003, Stranded Costs Work Group meeting in the above-referenced proceeding, pursuant to the April 30, 2003, email request for comments.

The National Energy Marketers Association (NEM) is a national, non-profit trade association representing wholesale and retail marketers of energy, telecom and financial-related products, services, information and related technologies throughout the United States, Canada and the U.K. NEM's Membership includes wholesale and retail suppliers of electricity and natural gas, independent power producers, suppliers of distributed generation, energy brokers, power traders, and electronic trading exchanges, advanced metering and load management firms, billing and information technology providers, credit, risk management and financial services firms, software developers, clean coal technology firms as well as energy-related telecom, broadband and internet companies.

This regionally diverse, broad-based coalition of energy, financial services and technology firms has come together under NEM's auspices to forge consensus and to help resolve as many issues as possible that would delay competition. NEM members urge lawmakers and regulators to implement:

- Laws and regulations that open markets for natural gas and electricity in a competitively neutral fashion that bring suppliers and consumers together at the lowest possible cost;
- Standard rates, tariffs, taxes and operating procedures that unbundle competitive services from monopoly services and encourage true competition on the basis of price, quality of service and provision of value-added services;

- Accounting and disclosure standards to promote the proper valuation of energy assets, equity securities and forward energy contracts, including derivatives; and
- Policies that encourage investments in new technologies, including the integration of energy, telecom, digital communications and Internet services to lower the cost of energy and related services.

Introduction

As an initial matter, NEM recommends that the methodology for calculating "just and reasonable net stranded costs" must be implemented in a manner that provides market participants with long term certainty as to the amount of the charge and the duration over which it will be imposed. Competitive providers need long-term certainty as to the viability of the Virginia retail marketplace before they will make the infrastructure investments necessary to serve retail access customers.

Question 1. Requested Actions paragraph 9 of the Legislative Transition Task Force (LTTF) Resolution requests that the work group "Include in its reports to the LTTF any recommendations for legislative or administrative action that the Commission, the work group, or both, determine to be appropriate in order to address any overrecovery or underrecovery of just and reasonable net stranded costs." **Please discuss whether the definitions and/or methodologies discussed by the work group might require any action as contemplated by Requested Action #9. Discuss what action may be necessary, the timing of that action, and why it is necessary.**

NEM submits that the requirement imposed by Section 56-583(B) that the wires charge be assessed to retail access customers only is a major statutory constraint faced by the Work Group. Net stranded costs should be collected on a competitively neutral basis. This provision prevents that result by penalizing customers that switch with a wires charge to collect stranded costs. NEM submits that the wires charge as currently instituted is a major barrier to competitive entry. NEM urges the Commission and the Work Group to recommend that the legislature reexamine Section 56-583(B) consistent with the Commission's authority, vested in Section 56-596, to, "take into consideration, among other things, the goals of advancement of competition and economic development in the Commonwealth."

NEM suggests that in reexamining Section 56-583(B) the legislature consider that recovering stranded costs solely from departing customers penalizes consumers who shop for lower priced energy and should not be permitted for a number of reasons as set forth below including: a) all customers benefit from robust retail energy price competition; b) competitively neutral charges are necessary to provide market participants with long term certainty to make investments in the Virginia market; c) if stranded cost charges are not assessed on a competitively neutral basis, inaccurate price signals will be sent to consumers; d) a competitively neutral stranded cost charge will eliminate the issue of uncertainty with respect to using retail open access load forecasts to set charge amounts; and e) a competitively neutral stranded cost charge will avoid the "retail access death spiral" effect. (See NEM's Initial Comments, Response to Question 4, http://www.energymarketers.com/documents/NEM_stranded_cost_cmts_final.pdf).

Question 2, 3, and 4. The Work Group Stranded Cost Recovery Proposals

The proposals submitted to the Work Group do not address the issue of whether the "unavoidable" costs at issue are, in fact, costs properly attributable to Provider of Last Resort-related services. NEM submits that any determination of costs that are truly stranded must necessarily address the issue of whether the "unavoidable" costs at issue are, in fact, costs properly attributable to Provider of Last Resort-related services. Accordingly, NEM urges the Commission to implement embedded cost-based unbundled rates at the earliest possible time and to quantify the levels of migration and monitor utility mitigation efforts prior to developing just and reasonable methods to recover stranded costs. This will ensure that utilities receive the appropriate revenue requirements based on the embedded costs associated with the actual services provided to migrating customers versus full sales customers versus POLR customers.

NEM recommends that any costs that are unavoidable because utilities must incur such costs to perform Provider of Last Related (POLR)-related services should be recovered through adjustments to the rates charged for POLR-related services. Utilities should not be permitted to recover revenue shortfalls through a transition surcharge in delivery rates based on a formula that assumes all unavoidable costs are caused by migration rather than by the necessity to provide POLR-related services. Any actual unrecovered costs or revenues lost that are not connected with the utilities' provision of POLR-related services and/or fully bundled sales service should be added to distribution rates in a competitively neutral fashion.

A. Earnings Test Mechanism

The Earnings Test Mechanism proposes that a "bundled earnings test . . . be used until such time as bundled, capped rates are terminated" and that "a functionalized cost of service study" be undertaken. As an initial matter, NEM believes that utility rates should be unbundled, as soon as reasonably practicable, based on the utilities' fully embedded costs. Unbundled utility rates based on fully embedded costs allow utilities to both quantify and, if properly mitigated, recover stranded costs within a reasonable time frame. Properly unbundled utility rates also provide customers and competitors with true, accurate price signals that will permit meaningful price competition in the shortest possible time. When utilities' rates reflect and utility customers pay less than fully embedded costs, customers end up paying an artificially low, subsidized price for competitively available services. This situation will slow customer migration and cause utilities to continue to incur costs for competitive services that may ultimately become stranded.

B. DVP Method

Under the DVP method, a utility will compare the revenue collected annually from switching customers via the wires charges, based on the projected market prices established by the Commission, to the revenue that would have resulted had wires charges been based on the actual market prices experienced during that year. The DVP method, self-admittedly, cannot finally determine the over- or under-recovery of a utility's total stranded costs until after July 1, 2007. NEM is concerned that the DVP proposal will not provide any future certainty on the level of net stranded costs to be collected through the wires charges and bundled rates until after the transition period has expired. Therefore, consumers will not be able to commit to enter into long-term contracts with competitive service providers (CSPs) because a component of future rates will be unpredictable. This is not conducive to the development of a competitive market, and will do little to attract competitive suppliers to the Virginia market.

C. NEM's Recommendations

NEM recommends that the methodology for calculating "just and reasonable net stranded costs" should be implemented after just and reasonable unbundled rates or shopping credits based on fully embedded costs have been implemented and actual migration has occurred. A reasonable period of time (e.g. one year or a migration rate of 25%) should be given to customers to comparison shop with shopping credits based on fully embedded cost-based unbundled rates (i.e. credits against utility bills) for contestable services.

Once a reasonable time (e.g. one year or 25% migration) has elapsed during which consumers are able to shop for one or more competitive services with embedded cost-based credits, then a calculation of the difference between the revenues that the utility would have received using fully embedded cost-based rates and the revenues actually received by the utility due to lost sales of specific services from the menu of competitive products, services, information and technology that each customer actually elects to purchase from the utility versus a competitive supplier should be compared to determine the maximum amount of potentially "qualifying revenue losses" that may be arguably recoverable, subject to the following qualifications:

1. The utility must show that the costs are material.
2. The utility must demonstrate that they have productively managed and reasonably mitigated costs in the subject areas.
3. The utility must not be earning in excess of their earnings/sharing cap, and
4. The utility must identify specifically which costs or revenue losses are a result of (a) the utility being required to provide POLR services and/or (b) the utility's need to provide fully bundled services to customers that do not migrate.

Conclusion

NEM appreciates this opportunity to comment on just and reasonable net stranded costs and reiterates our commitment to working with the Commission and the other stakeholders to devise fair and effective ways to implement competitive restructuring in Virginia.

Sincerely,

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Dated: May 8, 2003.

- Section 56-595.C (iii) of Virginia's Electric Utility Restructuring Act ("Act") provides that the members of the Legislative Transition Task Force ("LTTF") " ... shall: ... monitor ... whether the recovery of stranded costs, as provided in § 56-584, has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs.

- To monitor an "over-recovery" or "under-recovery," the LTTF must determine and compare two amounts: first, the amount that has been, or will be, available for recovery of just and reasonable net stranded costs, and, second, the amount of just and reasonable net stranded costs.

- Section 56-584 of the Act provides for two sources of revenue for the recovery of just and reasonable net stranded costs -- capped rates and wires charges.

- Thus, the amount that has been, or will be, available for recovery of such costs is the net revenue collected from wires charges and capped rates. Because the incumbent utility must collect sufficient revenue to recover its costs of providing service, the net revenue available for the recovery of just and reasonable net stranded costs is the revenue from capped rates and wires charges in excess of the revenue needed by the utility to recover its costs of providing service (*i.e.*, the utility's revenues in excess of its "revenue requirement").

- The following approach recognizes both sides of the inquiry required of the LTTF – *i.e.*, (i) the amount of just and reasonable net stranded costs and (ii) the amount available for recovery of such costs through wires charges and capped rates.

    To calculate just and reasonable net stranded costs compare asset values based on the net present value of the difference between the revenues that arise from remaining in a regulated market (cost plus a fair return) and the revenues that arise in a competitive market (over the life of the assets). From this amount subtract revenues via capped rates (to the extent capped rates exceed actual and likely costs including a fair return) and wires charges to determine the over- or under-recovery of just and reasonable net stranded costs.

- The above approach represents an acceptable, administrative methodology for the calculation of both just and reasonable net stranded costs and their recovery under the Act. By reference to the "regulated market (cost plus a fair return)," the methodology incorporates traditional ratemaking concepts in a regulated environment, including consideration of a utility's regulated cost of service used in setting "just and reasonable" rates, and including concepts of "prudence," mitigation, verification, and the "netting" of stranded costs and margins. The methodology properly requires consideration of the useful life of assets.

- As is true of any administrative method of determining stranded costs, the above approach involves estimates based on long-term revenue and cost projections. Such estimates are data-intensive and highly sensitive to the underlying assumptions and models used in making them. Long-term projections, however, are almost always used, implicitly or explicitly, in valuing assets for commercial purposes. Reasonable forecasts of items affecting such calculations and the development of estimates under reasonable scenarios would be required.

- Incumbent electric utilities must make annual informational filings ("AIFs") that include specified financial information with the State Corporation Commission. The Commission reviews such AIFs for compliance with Commission requirements for accounting and ratemaking treatment of costs and revenues. As approved by the Commission, AIFs would provide an acceptable basis for calculating a utility's historical cost of providing service and any revenues in excess of those costs that may be available for recovering stranded costs.