ANDREWS & KURTH L.L.P.
A REGISTERED LIMITED LIABILITY PARTNERSHIP
ATTORNEYS
1701 PENNSYLVANIA AVENUE, N.W.
SUITE 200
WASHINGTON, D.C. 20006-5805

OTHER OFFICES:
HOUSTON
DALLAS
LOS ANGELES
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THE WOODLANDS
LONDON

TELEPHONE:(202) 662-2700
TELECOPIER:(202) 662-2739
TELEX: 79-1208

ROBERT M. LAMKIN
202-662-2779



February 9, 1998



**VIA OVERNIGHT MAIL**



James J. McNulty
Prothonotary
Pennsylvania Public Utility Commission
North Office Building
Commonwealth Avenue and North Street
Harrisburg, Pennsylvania 17120

Re: Duquesne Light Company Restructuring Proceeding,
Docket No. R-00974104

Dear Mr. McNulty:

Pursuant to Sections 1.4 and 5.502 of the Pennsylvania Public Utility Code, enclosed please accept for filing: (1) an original and nine (9) copies of the Public Version (Protected materials redacted) Main Brief of Hospital Shared Service ("HSS") and Administrative Resources, Inc. ("ARI"); and (2) an original and nine (9) copies of the Confidential Version of the Main Brief of HSS and ARI in the above-captioned proceeding.

Also, please find an additional copy of the cover of the Main Brief for each of the two versions to be stamped and returned to me in the enclosed self-addressed postage prepaid envelope.

Sincerely,

Robert M. Lamkin
One of Counsel for Hospital Shared Services
and Administrative Resources, Inc.

Enclosures

cc: Judge Corbett (w/encl.
and computer diskette version)
Service List



90

ORIGINAL

**REDACTED -- PUBLIC DISCLOSURE VERSION**

**BEFORE THE**
**PENNSYLVANIA PUBLIC UTILITY COMMISSION**

| | | |
|---|---|---|
| Pennsylvania Public Utility Commission, | ) | |
| v. | ) | Docket No. R-00974104 |
| Duquesne Light Company Application to approve restructuring plan pursuant to 66 Pa. C.S. § 2806(d) | ) | |



**MAIN BRIEF OF**
**HOSPITAL SHARED SERVICES AND**
**ADMINISTRATIVE RESOURCES, INC.**



February 10, 1998

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**BEFORE THE**
**PENNSYLVANIA PUBLIC UTILITY COMMISSION**

| | | |
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| Pennsylvania Public Utility Commission, | ) | |
| v. | ) | Docket No. R-00974104 |
| Duquesne Light Company Application to approve restructuring plan pursuant to 66 Pa. C.S. § 2806(d) | ) | |

To: The Honorable John H. Corbett, Jr.
Presiding Administrative Law Judge

**MAIN BRIEF OF**
**HOSPITAL SHARED SERVICES AND**
**ADMINISTRATIVE RESOURCES, INC.**

Pursuant to interim orders of the Presiding Administrative Law Judge, Hospital Shared Services ("HSS") and Administrative Resources, Inc. ("ARI")[1] hereby submit their main brief. [2]

---

[1] The following entities support the participation of Hospital Shared Services ("HSS") and Administrative Resources, Inc. ("ARI") in this proceeding:

Allegheny General Hospital
Children's Home/Pittsburgh
Forbes Metropolitan Hospital
Forbes Nursing Center
Forbes Regional Hospital
Gateway Rehabilitation Center
Healthsouth Harmarville
LGAR Health & Rehabilitation Center
Ohio Valley General Hospital
Presby SeniorCare/Allegheny
Riverview Center for Jewish Seniors
St. Clair Hospital
Vincentian Home

South Hills Health System:
James Bibro Pavilion
Jefferson Health Services/Homestead

(continued...)

## I. INTRODUCTION AND SUMMARY OF ARGUMENT

### A. Introduction

This case presents significant challenges to the intervenors and the Pennsylvania Public Utility Commission ("Commission"), perhaps far in excess of the challenges presented by the restructuring cases filed by any of the other utilities in the Commonwealth. There are two reasons that support that conclusion.

The first of those reasons is that Duquesne Light Company's ("Duquesne") approach to this case has been, and continues to be, a moving target. The tests it proposes for qualifying for stranded cost recovery change as Duquesne's recalculates its alleged stranded costs, and the proposals that Duquesne would have the Commission approve vary dependent upon circumstances such as the status of the proposed merger of Duquesne with Allegheny Power Systems ("APS") or the

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[1](...continued)

Jefferson Hospital
Jefferson Surgery Center

*University of Pittsburgh Medical Center:*
UPMC/Beaver Valley
UPMC/Braddock
UPMC/Montefiore
UPMC/McKeesport
UPMC/Passavant
UPMC/St. Margaret
UPMC/Seneca Place
UPMC/Shadyside
UPMC/Southside
UPMC/The Heritage

[2] The structure of the brief follows the specified outline. In those instances where HSS/ARI have taken no position on an issue, the heading for that issue has been omitted.

willingness of the Commission to allow Duquesne to defer specification of a stranded cost claim that in Duquesne's view satisfies the known and measurable standard. Nonetheless, there is one undisputed fact that demonstrates that Duquesne's proposals in all forms must be rejected.

Duquesne's President and Chief Operating Officer testified that he would not commit Duquesne to sell power at the prices forecast by Duquesne's witness Schnitzer. Marshall, Tr. 83:1-84:5. That is compelling because Schnitzer's price forecasts lie at the heart of Duquesne's contention that it has stranded costs, and it is that single claim that Duquesne relies upon with respect to every proposal that it has put forward for the Commission's consideration. Thus, Duquesne is asking the Commission to impose stranded cost liabilities upon ratepayers potentially in a range of $2 billion notwithstanding the risk that Schnitzer's forecast will turn out to be wrong, although Duquesne is unwilling for its shareholders to bear that same risk. Duquesne also is asking the Commission to impose that liability on ratepayers based upon Schnitzer's price forecasts notwithstanding that Mr. Marshall expressly testified that he does not support Duquesne's claim of $1.9 billion that is based upon Schnitzer's price forecasts (Marshall Tr. 79:4-7), presumably because in Marshall's opinion, Schnitzer's post-2005 price projections (which are critical both to Duquesne's 1999 and post-2005 stranded cost calculations) are inconsistent with the known and measurable standard. Marshall, Tr. 82:21-25. Given Mr. Marshall's testimony, there is no basis upon which to grant any of Duquesne's requests.

The second reason that this case presents significant challenges relates to the remedies required in the absence of record support for Duquesne's proposals. At first glance, those remedies may appear to be harsh. Nonetheless, Duquesne had the burden of proving that it has net known and measurable stranded costs, and it did not satisfy that burden. Moreover, alternate stranded cost

estimates (marginally lower than Duquesne's estimate) sponsored by the Office of Consumer Advocate ("OCA") and the Duquesne Industrial Intervenors ("DII") are based upon computer-generated price forecasts that are no more reliable than those of Mr. Schnitzer.

On the other hand, there is substantial evidence in this case that demonstrates that Duquesne's generation assets have positive market value and that, as a consequence, Duquesne has no stranded costs at all. That evidence consists of studies performed by Duquesne, itself, and its consultants, as well as corroborating evidence in the form of actual market transactions, the sum total of which constitute compelling evidence of the positive market value of Duquesne's generation assets. That evidence, thus, demonstrates that the required remedies are not harsh; they merely put Duquesne in the position in which it should be in view of the actual market value of its assets. As a result, it is appropriate and necessary to provide ratepayers the rate relief to which they are entitled.

**B. Summary**

The Electricity Generation Customer Choice and Competition Act (the "Customer Choice Act" or "Act"), 66 Pa. C.S. §§ 2801-13 (1997), provides an electric utility the opportunity to recover through a nonbypassable Competitive Transition Charge ("CTC") the utility's net known and measurable stranded costs. Thus, the predicate for a utility obtaining authority to charge a CTC is that the utility carry its burden of proof by establishing that it has net known and measurable stranded costs. 66 Pa. C.S. § 2803 (1997) (definition of transition or stranded costs). Absent the utility satisfying that burden, the utility has no right under the Act to charge a CTC.

Notwithstanding that standard, Duquesne submitted an application in this case in which it proposed to charge a CTC but failed to set forth a specific stranded cost claim as of January 1, 1999, the date upon which it would commence charging the CTC under its proposal. Exh. RBW-2, p. 2.

Duquesne failed to set forth that quantification based upon its assertion that administrative or computer-generated stranded cost quantifications inherently are unreliable such that they cannot satisfy the known and measurable standard. Duquesne Statement No. 1 at 14:12-14. Even though it did not set forth a specific claim that it had known and measurable stranded costs as of January 1, 1999, in addition to proposing to charge a CTC, Duquesne proposed:

(1) that it be permitted to accelerate $1.7 billion in amortization and depreciation allegedly to offset any stranded costs Duquesne might have (the effect of which would be to increase artificially Duquesne's generation-related revenue requirement);

(2) that it be permitted to continue to charge the equivalent of its current unreasonably high rates so that Duquesne can recover the inflated revenue requirement that results from accelerating amortization and depreciation; and

(3) that at some time in the future (perhaps 2002 or 2003) a final valuation would be performed to determine Duquesne's stranded costs based upon market data.

The obvious questions given Duquesne's application and proposal are: how does Duquesne claim to support collection of a CTC (which by definition is the recovery mechanism for net known and measurable stranded costs), and how does Duquesne attempt to justify its request to accelerate amortization and depreciation of $1.7 billion, if Duquesne has not shown that it has stranded costs in the first place? The answer is: by a slight of hand designed to camouflage the fact that Duquesne's case, in each of its variations, relies upon the very type of computer-generated stranded cost claim that Duquesne testified does not satisfy the known and measurable standard.

HSS/ARI will show herein that the Duquesne case is a house of cards.[3] Its most obvious shortcoming is that Duquesne's requests for stranded cost recovery (inclusive of its request to accelerate amortization and depreciation) rely upon the very methodology (computer-generated price projections), and specific price projections ( Schnitzer's), that Duquesne testified are inadequate for purposes of satisfying the statutory requirement that a utility establish its net known and measurable stranded costs. Duquesne Statement No. 1 at 14:12-14; Marshall, Tr. 83:1-84:5. In that regard, Duquesne's original proposals as set forth in its direct testimony all were based upon its position that as of December 31, 2005, it would have remaining stranded costs in a range of $8 million to $582 million. Duquesne Statement No. 2 at 29:20-22; Exh. DJC-3 at 1. And, Duquesne's more recently modified positions are based upon its claim that as of January 1, 1999, it will have stranded costs of $1.916 billion. Duquesne Statement No. 2R at 12:3-21; Exh. DJC-20 at 1. Given that each of those stranded cost claims are derived directly from Schnitzer's price projections, there simply is no basis to accept Duquesne's evidentiary presentation in support of its proposals.

Equally compelling is the fact that Duquesne failed to bring to the Commission's attention a wealth of evidence that shows that Duquesne has no stranded costs and/or has not taken adequate measures to mitigate any stranded costs it arguably might have. For instance, in contrast to its current claim that its generation assets have negative market value of $1.9 billion, Duquesne did not produce to the Commission Duquesne's own internal study that shows that Duquesne estimated that its sales of its generation assets could "add $500-$750 million in after tax cash for investing." Exh.

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[3] Indeed, Duquesne's decision to waive cross-examination of all witnesses may well indicate Duquesne's apprehension in having live witnesses describe the many shortcomings in its application.

RBW-3, at 12. Duquesne also failed to apprise the Commission of studies performed for it by its financial advisor, just eight months prior to the filing of Duquesne's application, that show that a sale of Duquesne's generation assets could produce premiums over net book value in a range of $377 million to $734 million. HSS/ARI Statement No. 1, at 21; *see also* Exh. RBW-10.

Also, notwithstanding its contentions that real market data reflecting actual market transactions are more reliable than administrative determinations, Duquesne failed to bring to the Commission's attention the results of Duquesne's sale of its interest in the Ft. Martin plant and the implications of that sale to a valuation of Duquesne's remaining generating assets. That actual sale, which fetched a purchase price approximately 4.5 times net book value, corroborates the findings of Duquesne and its financial advisors. Duquesne also failed to apprise the Commission of corroborating evidence that shows that there is a robust market bidding to purchase generation assets and that generation assets around the country currently are being sold at multiples of net book value.

Duquesne claims in it rebuttal testimony that a Commission decision rejecting Duquesne's stranded cost claim and Duquesne's rate proposals would result in a massive write-off that could affect Duquesne's financial integrity. Duquesne Statement No. 2R at 45:17-20. However, as Duquesne's own Treasurer essentially admitted, that claim is not a relevant factor if its consideration would require the Commission to grant Duquesne stranded cost recoveries that are not authorized by the Act.[4] Clayton, Tr. 276:5-277:17. Thus, the only relevant consideration in this case is: did

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[4] Further, HSS/ARI submit that Duquesne's threat to write-down its assets is not justified in any event. Financial Accounting Standard ("FAS") No. 121, the rule that Duquesne relies upon for its threatened write-down (Clayton, Tr. 255:17-256:23), does not authorize that write-down. In discussing the evidence that is needed to measure an impairment of expected future cash flows, FAS 121 provides, *inter alia*, that "[t]he weight given to the evidence [of estimates of (continued...)

Duquesne make the statutory required showing that it has net known and measurable stranded costs. HSS/ARI will show below that the evidentiary record leads only to one conclusion, *i.e.*, Duquesne failed to satisfy that standard. HSS/ARI will show that Schnitzer's price projections are not credible, *inter alia*, because they are based upon input assumptions that unreasonably minimize future market prices. HSS/ARI also will show that Duquesne's cost projections are far in excess of reasonable levels. HSS/ARI also will discuss in detail the substantial evidence, referred to above, that indicates that Duquesne's facilities have positive market value.

Based upon the foregoing, HSS/ARI submit that Duquesne's stranded cost claim should be denied in its entirety. As a result, HSS/ARI ask that the Commission deny Duquesne's request to accelerate amortization and depreciation of its generation assets. HSS/ARI further ask that the Commission require Duquesne to reduce immediately the generation component of its rates and its distribution rates, as well. Finally, HSS/ARI ask that the Commission reject Duquesne's request to delay a final valuation of its generation assets until 2002 or 2003. In support of these requests, HSS/ARI state as follows:

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[4](...continued)
expected future cash flows] should be commensurate with the extent to which the evidence can be verified objectively." HSS/ARI Cross Examination Exh. 2 at 3, ¶ 9. HSS/ARI submit that notwithstanding Mr. Clayton's claim to the contrary (Clayton, Tr. 260:6-19), an estimate of expected cash flow that relies upon Mr. Schnitzer's price forecasts cannot be verified objectively. Further, in view of Mr. Marshall's testimony, Duquesne could not even project for accounting purposes an estimate of expected cash flow based upon Mr. Schnitzer's price forecasts. As a result, FAS 121 would not provide Duquesne grounds to take a write-down as a result of the Commission rejecting Duquesne's stranded cost claim, a claim that, after all, is based upon Mr. Schnitzer's unverifiable and unreliable price projections.

## III. TRANSMISSION AND DISTRIBUTION RATES; UNBUNDLING ISSUES

### A. Introduction

A primary requirement of the Customer Choice Act is that utilities "unbundle" the generation, distribution and transmission components of their rates. 66 Pa. C.S. §2804 (3). While the Act provides that absent certain exceptions, not relevant here, a utility may not charge unbundled rates that exceed capped levels approved as of January 1, 1997, the Act does not impose a rate freeze that requires ratepayers to pay existing transmission and distribution rates if those rates exceed just and reasonable levels. To the contrary, because the transmission and distribution components of a utility's rates will continue to be regulated under Chapter 13 of the Public Utility Code, the rates for those components must be just and reasonable. *Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code,* Docket No. R-00973953 (December 11, 1997) (hereinafter "PECO Order") *mimeo* at *61; see also* 66 Pa. C.S. §1301. As a result, the Commission expressly has held that parties may challenge utilities' existing transmission and distribution rates in restructuring proceedings. *Id.* The right to challenge Duquesne's distribution rates is particularly important because those rates are based, *inter alia*, upon hundreds of millions of dollars of past and projected capital expenditures that never have been shown to be just and reasonable. Further, a review of the evidence demonstrates that Duquesne presented no evidence in this case to attempt to show that either its past or projected distribution-related capital expenditures are just and reasonable. As a result, Duquesne's distribution rates should be reduced immediately.

## B. 1996 Test Year Cost Of Service

In considering issues concerning Duquesne's distribution rates, it must be remembered that Duquesne, of its own volition, has not filed a rate case since 1986. Duquesne Statement No. 4 at 22:15-20. Indeed, Duquesne's decision not to file a rate case appears to have been part of a purposeful corporate strategy. *See, e.g.*, Exh. RBW-28, p-0059146 ("No base rate cases anticipated"); *see also* HSS/ARI Statement No. 1 at 80:18-22. Thus, the Commission has not reviewed any of the capital or other expenditures that Duquesne made associated with its distribution cost of service for over a ten year period. As a consequence, Duquesne had the burden of establishing that its expenditures over that ten year period were just and reasonable to the extent that those costs are subsumed within Duquesne's current distribution rate structure. 66 Pa. C.S. § 315 (A). As the Commission has held in other proceedings, "[i]f and when [a utility] seeks recognition of [capital expenditures], it will then be required to support the prudence of those expenditures." *Pennsylvania Public Util. Comm'n v. Philadelphia Electric Co.*, Docket No. R-891364, *et al.*, 1990 Pa PUC Lexis 155 at p* 54-57 (1990). Additionally, a utility has the burden of proof with respect "to the total amount of the claimed costs," as well. *Id.* at 57. Notwithstanding those evidentiary burdens, Duquesne produced no evidence whatever to support its past capital expenditures. Therefore, Duquesne's distribution rates should be reduced from current levels to eliminate the impact of costs that Duquesne has not justified.

According to Duquesne's testimony, as of December 31, 1996, Duquesne's total investment in distribution plant was $1,233,255,730.00. Exh. MKO-1A, page 7 of 17. Also at the end of test year 1996, Duquesne had accumulated depreciation of $372,851,189.00. *Id.* at page 10 of 17. As a result, Duquesne claimed net book value of distribution plant in the amount of $860,374,541.00.

*Id.* at page 13 of 17. That net book value is the major component of Duquesne's distribution-related rate base for purposes of deriving unbundled distribution rates. *See* Exh. MKO-1C, page 1 of 13. That net book value necessarily includes substantial costs of capital additions that Duquesne never has shown to be just and reasonable.

Duquesne's FERC Form 1 reports show that between 1987 and 1996, during which time Duquesne chose not to file a rate case, Duquesne made distribution related capital expenditures of approximately $473 million. HSS/ARI Statement No. 1, at 55-56. HSS/ARI's witness, Dr. Robert B. Weisenmiller, set forth those data in his direct testimony and stated that "Duquesne's past capital expenditures obviously must be considered in the context of determining whether Duquesne's proposed rates are reasonable." *Id.* at 57:7-8. Nonetheless, neither in its rebuttal testimony nor at any other time did Duquesne attempt to rebut Dr. Weisenmiller's testimony directly, nor did Duquesne introduce any evidence to attempt to suggest that its past capital expenditures were just and reasonable.

Section 1301 of the Public Utilities Code provides that "[e]very rate made, demanded, or received by any public utility . . . *shall* be just and reasonable . . ." 66 Pa. C.S. § 1301 (emphasis added). Further, the Commission has held that:

> [t]here is no presumption of reasonableness which attaches to a utility's claims, at least none which survives the raising of credible issues regarding a utility's claims. A utility's burden is to affirmatively establish the reasonableness of its claim. It is not the burden of the other party to disprove the reasonableness of the utility's claims.

*Pennsylvania Pub. Util. Comm'n v. Equitable Gas Co.*, 57 Pa. PUC 423, 444 n.37 (1983). Thus, there is no basis to assume the reasonableness of Duquesne's past expenditures when

Duquesne itself never even addressed the issue. Given this circumstance, it would be entirely within the Commission's authority under *Pa. Pub. Util. Comm'n. v. Equitable Gas, supra* to require a disallowance of the entirety of Duquesne's 1987-96 distribution-related capital expenditures. However, that would be a harsh result because presumably some of Duquesne's expenditures were reasonable.

Nonetheless, the Commission should not assume that Duquesne's total expenditures were reasonable in the absence of any record support for that conclusion. Further, Duquesne should not be rewarded for an apparent corporate strategy of precluding the scrutiny of its rates as would have occurred had Duquesne filed a rate case during the last 10 years. Thus, to balance the interests of all concerned, HSS/ARI recommend that the Commission disallow 50% of the $473 million in distribution-related capital expenditures that Duquesne apparently made between 1986 and the present, and order the rate reduction that would result from that disallowance.[5]

### G. Other Issues

Just as Duquesne had the burden of establishing that its past capital expenditures were just and reasonable, it had the same burden with respect to its projected expenditures. 66 Pa. C.S. § 315 (A). However, just as in the case of its past expenditures, Duquesne made no attempt to demonstrate that its projected capital expenditures for distribution-related service are just and reasonable. It is paramount for the Commission to address the issue of those projected expenditures now rather than wait perhaps another decade for Duquesne to file its next rate case.

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[5] Of course, it also is within the Commission's authority to order a greater disallowance if the Commission believes that would be appropriate in the circumstances.

In considering this issue, it is important to review it in the context of Duquesne's proposal that it be permitted to maintain its current rates. That is an important consideration because Duquesne's cost of service study upon which its proposed rates are based does not assume an adjustment to 1996 test year data with respect to distribution plant. See Exh. MKO-1B, p. 6 of 12. However, that cost of service study is misleading in the context of Duquesne's overall rate proposal.

In Duquesne Exhibit DJC-3, Duquesne sets forth, *inter alia*, a revenue requirement forecast for generation, transmission and distribution. As can be seen on each page with revenue requirement forecasts for the years 1997 through 2005, Duquesne in all instances assumes a return on equity of 11.5% consistent with its proposal in this case. *See* Exh. DJC-3, pp. 2 through 22 of 67. Presumably, Duquesne intended, in noting the return on equity in the exhibits to suggest that through 2005, Duquesne likely would not earn more than its requested return on equity of 11.5% if it is permitted to continue to charge its current rates. However, Exhibit DJC-3 is revealing in terms of understanding the level of capital expenditures Duquesne will have to make to achieve such a result.

Specifically with respect to distribution-related capital expenditures, Exhibit DJC-3 reveals that between 1997 and 2005, Duquesne would have to make capital additions of $532 million (more than one-half of its current net plant investment) to provide a cost basis that would allow it to back-in to an 11.5 % return on equity. *See* Exh. DJC-3, pp. 22 and 28 of 67; *see also* HSS/ARI Statement No. 1 at 58. On its face, that level of projected capital additions appears excessive. Nonetheless, Duquesne did not offer any evidence even to explain the purported bases for the expenditures, let alone to attempt to demonstrate why such costs might be reasonable. Thus, one is left to ask: how excessive will Duquesne's return on equity be if Duquesne does not expend the forecasted amounts?

Similarly, one can ask: is there evidence to suggest just how excessive Duquesne's forecasted expenditures might be?

The answer to the first question concerning Duquesne's potential returns on equity is suggested by materials Duquesne presented in an August, 1996 rating agency presentation. As is shown in those materials, Duquesne projected returns on average common equity of 14.6%, 15.4%, 14.9%, 14.3% and 14% for the years 1996 through 2000, respectively. Exh. RBW-28, p. 0059280; *see also* HSS/ARI Statement No. 1 at 78; 1-14. Those projections are consistent with Duquesne's recent financial performance. For instance, in a September 23, 1997 presentation to NatWest Securities, Duquesne boasted that its earnings per share as of the twelve months ending June 30, 1997 were up by 8.4% from the prior 12-month period. Exh. RBW-29 at 2. Duquesne also boasted of annual compound growth rates in earnings per share and dividends of 8.0% and 6.2%, respectively. *Id.* at 3. Further still, Duquesne gloated that its 5-year growth rates in earnings per share was sixth highest of all ranked utilities; its 5-year growth in dividends per share was second highest of the ranked utilities; and, its payout ratio was lowest of all utilities. *Id.* at 4; *see also* HSS/ARI Statement No. 1 at 78:18-79:3. Thus, Duquesne's projections of distribution-related capital expenditure appear to be designed to help Duquesne maintain its substantial financial achievements for its shareholders, with no commensurate benefit for its ratepayers.

The evidentiary record also provides for a conclusion concerning the question of just how excessive Duquesne's projected capital expenditures might be.

**PROTECTED MATERIALS**
**REDACTED**

As a result, at a minimum, it is appropriate to adjust Duquesne's

proposed distribution rates to assume future capital additions of 10% less than forecast by Duquesne. *See* PECO Order, *mimeo* at 82.

Further, relying upon *Green v. Pa. Pub. Util. Comm'n.*, 473 A.2d 209; 81 Pa. C.S. 55 (1984), the Commission has held that it should disallow expenses projected more than 12 months after a rate case test year. *Pennsylvania Pub. Util. Comm'n. v. Pennsylvania Power & Light Co.*, 67 PUR 4th 30, 50-51 (1985). As a result, particularly given the lack of any evidence to support Duquesne's projected expenditures, it also is appropriate for the Commission to disregard Duquesne's distribution related projections in their entirety and assume a declining rate base that would result from straight line depreciation. To do otherwise would assume without foundation that Duquesne will make certain expenditures that it has not shown are known and measurable. It also would place Duquesne in a position (particularly in the out years as it depreciates existing plant) to extract a return on equity well in excess of the 11.5% return it claims to be requesting.

**H. Conclusion**

For the reasons set forth above, Duquesne's distribution-related rate base should be reduced to eliminate 50% of the net book value associated with Duquesne's 1987-96 distribution-related capital expenditures of $473 million that never have been shown to be just and reasonable. Further, Duquesne's 1996 test year distribution-related rate base should be reduced to reflect a declining rate base through the year 2005 consistent with the effect of straight line depreciation.

## IV. TRANSITION OR STRANDED COSTS

### A. Overview of Stranded Cost Valuation and Recovery Approaches

#### 1. Introduction

The Customer Choice Act requires the Commission to determine the amount of stranded cost recovery that is just and reasonable. 66 Pa. C. S. §§ 2804(13), 2804(14); PECO Order, *mimeo* at 63-64. To determine the amount of recovery ultimately found to be just and reasonable, the Commission must first identify the level of stranded costs that "actually exist" pursuant to the definition of "transition or stranded costs" provided in the Act. PECO Order at 64. Section 2803 of the Act defines "transition or stranded costs" as follows:

> [a]n 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.

66 Pa. C. S. § 2803. Duquesne thus has the "burden to prove, based on substantial evidence in the record, that each [stranded cost] request would recover the net present value of the unmitigated, net, known and measurable generation related expense within the definition of stranded costs." PECO Order at 68. Moreover, Duquesne has the "burden to prove that such costs would have been recoverable under traditional regulation but will not be recoverable in a competitive market." *Id.* Duquesne has failed to meet its burdens.

Duquesne's stranded cost claim inextricably is tied to its proposal to maintain its current rates. Duquesne claims an entitlement to maintain those rates based upon Section 2804(4)(v) of the Customer Choice Act which states:

> If an electric distribution utility rolls its energy cost rate into base rates at a combined level that does not exceed its combined level of such rates which have been approved by the Commission as of the effective date of this chapter, the utility shall not be required to reduce its capped rates below the capped level . . . *if* [1] *the Commission determines that any excess earnings achieved under the cap are being utilized to mitigate transition or stranded costs for the benefit of ratepayers or [2] to offset other known and measurable cost increases that would be recoverable under traditional ratemaking but are not included within the capped rates.*

66 Pa. C.S. § 2804(4)(v) (emphasis added). Duquesne claims an entitlement to the rate floor protection of that provision based upon Duquesne's proposal to accelerate depreciation and amortization of its generation assets by $1.7 billion through 2005 ostensibly for the purpose of mitigating stranded costs. However, Duquesne also insists that its stranded costs are not known and measurable at this time. Thus, Duquesne proposed that a valuation of its generation assets and stranded costs, if any, should take place in 2003 based upon a premise that public sources of objective market data will be available at that time to satisfy the known and measurable standard. Duquesne Statement No. 3 at 46:14-16; Duquesne Statement No. 1 at 14:17-18. As a result, Duquesne would have the Commission grant Duquesne authority to charge a CTC to recover stranded costs prior to an actual determination that Duquesne, in fact, has stranded costs to recover. As will be demonstrated below, however, Duquesne has not proven even on a preliminary basis that it has any stranded costs in the first place. Therefore, Duquesne has failed to carry its evidentiary burden that would serve as support for its request to accelerate amortization and depreciation. Thus, Duquesne's request to accelerate amortization and depreciation by $1.7 billion represents nothing more than an attempt by Duquesne to manufacture an inflated cost of service to attempt to justify the maintenance of exorbitant rates and collection of amounts in excess of those to which Duquesne is entitled under traditional ratemaking methodologies.

2. Duquesne's Approach

When Duquesne originally filed its application, Duquesne stated that it had to make two showings to establish a *prima facie* case to justify its rate proposals. First, Duquesne had to show that "a mechanism exists to ensure that if revenues under [its proposed] rate cap are greater than the normal cost of service, these 'excess earnings' will be used to mitigate transition or stranded costs . . . ." Duquesne Statement No. 3, at 22:6-8. Second, Duquesne stated that it "must demonstrate that stranded costs still remain in 2006 even after the 'excess earnings' mitigation . . . ." *Id.* at 22:14-15. Duquesne claimed to make the latter showing by claiming that as of December 31, 2005, it "likely [will] have remaining stranded costs of $8 to $582 million . . . ." Duquesne Statement No. 2 at 29:20-21. But, how did Duquesne derive its estimated range of claimed post-2005 remaining stranded costs? It did so by relying upon computer-generated market price projections notwithstanding Duquesne's compelling criticisms of those projections. Moreover, in Duquesne's case, those price projections are best characterized as nothing more than back of the envelop calculations.

Using a simple computer program of his own design, Duquesne's witness Schnitzer calculated future retail market prices in some cases out to the year 2026. To derive those price projections, Schnitzer input unreasonable assumptions into his computer and made unreasonably modest adjustments to Duquesne's summer 1997 wholesale RFP results, the net effect of which was to produce unreasonably low projections of future retail market prices. Based upon those price projections, Duquesne calculated revenues that it claimed it would gain (1) through 2005 and (2) through the retirement dates of its various plants (Schnitzer's projected market prices times projected plant output). *See* Exh. DJC-3. Duquesne then calculated its costs of operation assuming acceleration of $1.7 billion in amortization and depreciation. Based upon those cumulative data,

Duquesne claimed that as of 2006, its plants would have a net book value of $535 million, but market value only in a range of a negative $47 million to a positive $527 million depending upon whether Schnitzer's low or high price projections were used to determine the future operating margins for Duquesne's plants. It was Duquesne's comparison of those projected market values to net book investment as of December 31, 2005 that served as the basis for Duquesne's initial claim that, notwithstanding its acceleration of amortization and depreciation, Duquesne likely would have remaining stranded costs ranging from $8 million to $582 million as of January 1, 2006. Duquesne Statement No. 2 at 29:20-22; Exh. DJC-3 at 1.[6] Thus, it was the claimed market values derived principally from Schnitzer's price predictions that served as the basis for Duquesne's initial requests (1) that it be provided authorization to accelerate depreciation and amortization by $1.7 billion allegedly to mitigate stranded costs that Duquesne claimed otherwise would remain in 2006 and (2) that it be granted authorization to continue to charge its current rates.

However, Duquesne miscalculated the cost side of its equation. Duquesne was forced to admit that it had overstated its projected costs and that, as a result, as of January 1, 2006, Duquesne might not have any stranded costs at all. *See* Exh. RBW-1. Duquesne's corrected calculations, in fact, showed that its generation assets might have positive market value of as much as $233 million assuming Schnitzer's high case price projection. *See* Attachment A to Exh. RBW-1; *see also* Duquesne Statement No. 2R at 9:8-10. Thus, as HSS/ARI's witness, Dr. Weisenmiller, pointed out in his direct testimony, Duquesne would have flunked its own test for qualifying for its rate proposals based upon its own revised data, *i.e.*, Duquesne could not demonstrate that it was likely

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[6]$535 million (net book value)- $527 million (market value) = $8 million in stranded costs. $535 million (net book value)- ($47) million (market value) = $582 million in stranded costs.

that stranded costs still would remain in 2006 even after the excess earnings mitigation. HSS/ARI Statement No. 1 at 6:8-15.

As a consequence, in its rebuttal testimony, Duquesne modified its claim. In its rebuttal testimony, Duquesne claimed for the first time that it would have quantifiable stranded costs as of January 1, 1999 in the amount of $1.916 billion. Duquesne Statement No. 2R at 12:18-21; Duquesne Statement No. 3R at 2:12-14. The $1.916 billion claim was derived using a similar formulation to that described above. Again, Duquesne used Schnitzer's unreasonably modest adjustments to wholesale RFP results and computer-generated price projections to calculate plant revenues. Duquesne's witness Clayton then used those unreasonably low price forecasts to calculate projected plant margins, *i.e.*, the difference between projected plant revenues (Schnitzer's projected market prices times projected plant output) and Duquesne's unreasonably high projections of the costs of operating its plants. Clayton then netted those plant margins against the net book value of Duquesne's generation plants, costs Duquesne claims it will experience independent of operation of the plants and decommissioning costs to determine stranded costs of $1.9 billion that Duquesne now claims it will have as of January 1, 1999. Duquesne Statement No. 2R at 12; Exh. DJC-20, page 1 of 49.

To understand the significance of Schnitzer's price projections to Duquesne's claim, it is important to understand that Duquesne's $1.916 billion stranded cost claim is based upon Schnitzer's *low* case price projections. If one merely adjusts for Schnitzer's *high* case projection (another unreasonably low price forecast), Duquesne's stranded costs would be $1.537 billion, or $379 million lower than Duquesne's claim. And that almost $400 million reduction does not take into account a host of other adjustments that should be made that would raise Schnitzer's high case price

projections or reduce Duquesne's cost projections and claimed regulatory assets. Thus, an almost $400 million swing is produced by a mere penny per kWh swing in price projections used to determine revenues commencing in 2006. *See* Duquesne Statement No. 2R at 12; Exh. DJC-20 at p. 1 of 49. As a consequence, it is obvious that the significance of mere pennies in price projections is the difference between a stranded cost claim of almost $2 billion and a finding that Duquesne has no stranded costs at all. Thus, it is beyond dispute that the accuracy of Schnitzer's price projections are critical in determining whether Duquesne has the right to have the Commission approve any of Duquesne's proposals. More specifically, the accuracy of Schnitzer's price projections are critical in determining whether Duquesne has the right to charge a CTC while deferring an actual stranded cost calculation until some future time date.

3. HSS/ ARI Approach

HSS/ARI's approach to this case was to examine Duquesne's stranded cost claims in three different ways. As a first step, HSS/ARI examined the evidence that Duquesne relies upon as the basis for its stranded cost claim, both in terms of price and cost projections. The purpose of that examination was to determine whether, in HSS/ARI's view, Duquesne's evidence establishes that Duquesne has stranded costs. The need for that first step evaluation flows directly from the assignment to Duquesne of the evidentiary burden in this case.

A second way in which HSS/ARI approached this case was to examine documents produced by Duquesne itself in discovery and circumstances other than those relied upon by Duquesne. The purpose of examining such documents and circumstances was to determine whether there is evidence of the market value of Duquesne's generation assets other than the evidence relied upon by Duquesne.

HSS/ARI's third approach to this case was to examine facts and circumstances concerning Duquesne's mitigation efforts, or lack thereof.

As a result of its examination of the evidence, HSS/ARI has concluded that Duquesne failed to meet its burden and, thus, should be denied any stranded cost recovery. Duquesne failed to meet that burden for two principal reasons. First, its stranded cost claim, in all its variations, depends upon Schnitzer's computer-generated price projections. As HSS/ARI will discussed herein, the evidence shows that those price projections were derived in a manner to assure an unreasonably low result, the net effect of which was to maximize and overstate Duquesne's potential stranded costs. Thus, HSS/ARI agree with Duquesne's President and CEO that Schnitzer's computer-generated price projections are inconsistent with the known and measurable standard. Marshall, Tr. 83:1-84:5. The second principal reason that Duquesne failed to meet its burden was that it inflated its cost projections, as well. Thus, by understating projected market prices and overstating projected operating costs, Duquesne inappropriately maximized and grossly overstated its stranded cost claim. *See* Clayton, Tr. 265:17 - 266:14. HSS/ARI will discuss the evidence that demonstrates the flaws in Duquesne's price and cost projections in sections IV. B.3 and IV. B.4, respectively.

HSS/ARI also has concluded that there is substantial evidence relevant to an assessment of the market value of Duquesne's generation assets that Duquesne *did not* put in the record in this case. HSS/ARI will show in section IV. B.3(c), that actual valuations of Duquesne's assets performed by Duquesne and its consultants mere months before the filing of Duquesne's application show that Duquesne's assets have positive market value. Those studies, as well as evidence of market value demonstrated by actual market transactions, including, but not limited to, Duquesne's sale of its interest in the Ft. Martin plant, show that Duquesne has no stranded costs at all.

Finally, HSS/ARI will discuss evidence that demonstrates that notwithstanding Duquesne's claims that it intends to fully mitigate its claimed stranded costs, Duquesne has failed to undertake actions that could have or would mitigate any stranded costs Duquesne claims to have.

4. Conclusion

In view of Duquesne's failure to establish that it has net know and measurable stranded costs, substantial evidence that shows that Duquesne's generation assets have positive market value and Duquesne's failure to properly mitigate any stranded costs it claims to have, HSS/ARI request that the Commission:

(1) deny Duquesne's request to accelerate depreciation and amortization;

(2) deny Duquesne recovery of any amount claimed to be a stranded cost;

(3) deny Duquesne the right to charge its customers a CTC; and

(4) deny Duquesne's request to have its potential stranded costs reexamined through a final valuation conducted at some future date.

## B. Generation-Related Stranded Costs (Recovery Pursuant To Section 2808(3))

1. Introduction

Duquesne has failed to demonstrate that it will have any generation-related stranded costs as of January 1, 1999, nor has Duquesne demonstrated that it will have stranded costs as of January 1, 2006. Clearly, therefore, it has failed to satisfy the "known and measurable" standard imposed by the Customer Choice Act as a predicate to a utility recovering *any* stranded costs.

2. Net Book Value

(a) Total Net Book Value

Duquesne claims a total net book value of $918 million for its generation assets. Exh. DJC-10. Based upon certain adjustments set forth in Exhibit DJC-10, Duquesne would increase its net book value up to $1.236 billion to reflect certain generation-related expenses. Duquesne also claims to have $374.45 million in generation-related regulatory assets.

HSS/ARI do not dispute Duquesne's calculation of a net book investment in generation-related assets is $1.236 billion. However, HSS/ARI do object to the use of that net book value for purposes of establishing the generation component of Duquesne's rates or Duquesne's potential stranded costs. HSS/ARI will discuss here their objection to the inclusion in Duquesne's net book value the costs of capital additions made during the period 1986 to 1997. HSS/ARI will discuss in subsection (c), below, issues related to Phillips and Brunot Island costs. HSS/ARI will discuss its position with respect to Duquesne's regulatory asset claims in Section IV. E.

With respect to Duquesne's generation-related capital additions constructed since 1986, as was discussed previously in the context of Duquesne's distribution rates, it must be remembered that Duquesne has chosen not to file a rate case since 1986. Duquesne Statement No. 4 at 22:15-20. Thus, as is the case with Duquesne's distribution-related capital expenditures, the Commission has not reviewed any of the capital or other expenditures that Duquesne made associated with its generation cost of service for over a ten-year period. As a consequence, Duquesne also had the burden of establishing that generation related capital expenditures over that ten-year period were just and reasonable to the extent that those costs are subsumed within Duquesne's current generation rate structure. *Pennsylvania Pub. Util. Comm'n v. Philadelphia Electric*, 1990 Pa. PUC Lexis at p* 54-

57; 66 Pa. C.S. § 315 (A). However, as in the case of its distribution-related capital expenditures, Duquesne also produced no evidence to support its past generation-related capital expenditures.

Duquesne's FERC Form 1 reports show that between 1987 and 1996, exclusive of expenditures related to Beaver Valley 2 and Duquesne's initial capital expenditure of $743 million for Perry Unit 1, Duquesne made generation-related capital expenditures of approximately $382 million. HSS/ARI Statement No. 1, at 55-56. Again, given that Duquesne made no attempt to introduce any evidence that might suggest that its past generation-related capital expenditures were just and reasonable, it is within the Commission's authority to order a total disallowance of the $382 million in claimed generation-related capital expenditures. *Pennsylvania Pub. Util. Comm'n. v. Equitable.*, 57 Pa. PUC at 444 n.37, 66 Pa. C.S. § 1301. Nonetheless, to balance the interests as previously discussed, HSS/ARI recommend a 50% disallowance of that amount.[7]

(c) Recovery of Phillips and Brunot Island Costs

For purposes of considering Duquesne's stranded cost claim, its net book investment of $1.236 billion in generation-related assets also should be reduced to eliminate the net book investment associated with the Phillips and Brunot Island cold reserve capacity. That reduction would be in the amount of $106,800,000. Duquesne Statement No. 4:12-14. There are three principal reasons why that reduction is appropriate.

As Dr. Weisenmiller explained in unrebutted testimony:

> Duquesne took the units out of rate base, and placed them in cold reserve, in 1986 for two essential reasons. First, due to a 50 percent loss of its industrial load, Duquesne did not need the units to operate to serve its market. Exh. RBW-60 (p. 3, Paragraph 10). Second, and

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[7] *See also* n.5, *supra*.

> as a result of the first factor, Duquesne sought authority from the Commission to cold reserve the units, and take them out of rate base, as part of an "overall corporate program to substantially reduce costs *and reduce revenue requirements*." *Id.* at 5 (emphasis added).

HSS/ARI Statement No 1S at 24:14-20. Therefore, as Dr. Weisenmiller pointed out, if the costs of the cold reserved units are stranded, they are not stranded as a result of Pennsylvania's legislation that restructures the electric industry. Rather, to the extent any costs are stranded, they were stranded by Duquesne's loss of its industrial market over ten years ago. *Id.* at 24:20-25:2. In that circumstance, there is no reason why Duquesne's ratepayers should be forced to pay for Duquesne's investment in facilities due to the passage of legislation that has no impact on Duquesne's use or non-use of the cold reserved plants.

A second reason that Duquesne's net book investment should be reduced by the net book investment in Phillips and Brunot Island for purposes of considering Duquesne's stranded cost claim is that Duquesne should be held to the representations it made to the Commission in 1986 when it requested authority to cold reserve the units. As Exhibit RBW-60 shows, when Duquesne asked to take the units out of rate base, it did so to reduce its costs and its revenue requirement for the benefit of ratepayers. Exh. RBW-60 at 3 ¶11. Further, there was a presumption that the units would not be brought back into service unless and until there was a need to operate the units to serve Duquesne's market. *Id.* at 4, ¶13. As a result, as Dr. Weisenmiller testified, Duquesne should be held to its 1986 promise to reduce costs and not be permitted to shift financial responsibility to Duquesne's 21st century customers for the failure of load growth to materialize after 1979. HSS/ARI Statement No. 1S at 25:9-13. Indeed, that result is all the more appropriate given that Duquesne has no plans to

return the facilities to utility service. Duquesne Statement No. 2R at 32:23-25; *see also* Exh. DJC-21, pp. 24-26 of 141.

(d) Conclusion

For the foregoing reasons, for purposes of considering Duquesne's stranded cost claim, its net book investment should be considered to be $938 million to reflect the elimination of Duquesne's net book investment in the cold reserve portions of the Brunot Island and Phillips facilities and 50% of Duquesne's generation-related capital expenditures between 1986 and the present, none of which ever have been shown to be just and reasonable.

3. Market Value

(a) Introduction

In considering Duquesne's calculation of market value, *i.e.*, the key component of its stranded cost calculation, the testimony of Duquesne's President and CEO is critical. Mr. Marshall expressly stated in his direct testimony, and he confirmed during his cross-examination, that Duquesne believes that administrative (a code word for computer-generated) projections of future market prices are inconsistent with the known and measurable standard. Duquesne Statement No. 1 at 14:7-14; Tr. 61:1-4. And, when asked: is it Duquesne's position that it is entitled to $ 1.9 billion in stranded costs based upon an administrative determination, Mr. Marshall answered:

> We are saying that based on the best information we have today, that we estimate the number at 1.9 billion.
> [However, w]e do not believe that the method is adequate to determine a stranded cost calculation today.

Marshall, Tr. 75:13-21.

Similarly, Mr. Marshall testified:

based on the best information we have, what would the number be, it is 1.9, but when you say, do I support it, I don't support it . . . .

Marshall, Tr. 79:4-7.

And, Mr. Marshall responded as follows when asked:

Q. are Mr. Schnitzer's price projections -- now I'll make it very specific to the period 2006 and beyond -- are those price projections consistent with the known and measurable standard?
A. No.

Marshall, Tr. 82:21-25. Thus, given Mr. Marshall's testimony, the following discussion largely is academic because there can be no dispute that Duquesne has not submitted a stranded cost calculation that even Duquesne believes satisfies the statutory standard. Nonetheless, it is worthwhile to review the evidence to see how Duquesne determined a market value that by any reasonable assessment must be determined to grossly understate the real value of Duquesne's generation facilities.

(b) Market Price Projections

(i) Forecasting Methodology

Duquesne relied upon the testimony of Michael Schnitzer to determine market prices for purposes of its stranded cost calculations (both as of January 1, 1999 and as of December 31, 2005). In determining his market price projections, Schnitzer used a two-step process. First, he estimated future market prices for the period 1998 through 2005 using as a starting point for his analysis the results of Duquesne's summer 1997 Request for Proposals ("RFP"). Second, he input into a computer a handful of assumptions to derive price projections for the period 2006 until the book retirement date of each of Duquesne's generation facilities.

HSS/ARI will show that the adjustments Schnitzer made to Duquesne's RFP results were woefully inadequate to transform the result of Duquesne's wholesale auction of an incremental quantity of power into a price that reasonably is reflective of future retail market prices. Thus, Schnitzer's 1998-2005 price projections unreasonably understate likely prices at the retail level. HSS/ARI also will show that the assumptions that Schnitzer relied upon for his computer-generated post-2005 price projections also were designed to understate unreasonably future market prices. However, there is a preliminary matter that should be discussed that demonstrates why Schnitzer's price forecasts so grossly understate likely future market prices.

It is critical to understand that the starting points Schnitzer used in his two sets of calculations were unreasonably low, thus ensuring an understatement of future market prices. With respect to Schnitzer's 1998-2005 price projections, it is critical to understand why the prices paid in Duquesne's RFP were so low and, thus, wholly inadequate for purposes of estimating future market prices. And, with respect to Schnitzer's post-2005 price projections, it is critical to understand that his starting point, his estimates of the capital costs of combined cycle units, are so low that they are at odds not only with reality, but even with the specific source that Schnitzer touts as support for his estimates. Focusing on those two points in the following discussion demonstrates why even Duquesne and Mr. Marshall cannot support Schnitzer's price projections.

(ii) Input Assumptions (1998-2005)

There are two key input assumptions for Schnitzer's price projections for the period 1998 through 2005. His first assumption was that the results of Duquesne's RFP could serve as the starting point for the projection. The second was his apparent assumption that a mere 200 basis point risk adjustment factor would be adequate to solve for an equivalent all-hours retail spot price stream. *See* Duquesne Statement No. 3 at 34:4-7. As will be discussed below, Schnitzer's use of Duquesne's RFP results demonstrably was designed to produce an artificially low forecast of market prices.

Duquesne conducted an RFP in June of 1997 in which it offered to sell in a wholesale transaction a minimum of 50 MWs of firm power for a one-year period and a minimum of 100 MWs (with a maximum of 500 MW) of firm power for an eight-year period commencing on January 1, 1998. Duquesne Statement No. 7 at 6:4-8. According to Mr. Marshall, Duquesne sent out 300 notices to marketers around the country to participate in the RFP. Marshall, Tr. 156:8-12. Nonetheless, Duquesne received only five bids for the one-year sale and only eleven bids on the eight-year sale. *Id.* at 9:15-16; Irvin, Tr. at 823:18-20. That level of non-participation alone should have suggested to Mr. Schnitzer that there were factors at play that disqualified the RFP results from being a meaningful measure of market value.

In any event, as a result of the RFP, contracts were executed with two entities for a total sale of 50 MWs for one year, and with one entity for a sale of 100 MWs for the eight year period. Duquesne Statement No. 7 at 10:1-2. The weighted average price for the one-year sale was $18.16/MWh and the winning bid for the eight year sale was $20.19/MWh on a "nominal" levelized basis. *Id.* at 10:19 to 11:1. Mr. Schnitzer then adjusted those numbers, using his 200 basis point risk premium adjustment, an assumed inflation rate of 2.5% and assumed risk free and risk-adjusted

discount rates to determine a 1998 spot market price of 1.78¢/kWh. *See* Exh. MMS-4. Schnitzer projected that price out to 2005 based upon the assumptions previously discussed. *Id.*. Those price projections then were used to calculate the 1999-2005 portion of Duquesne's stranded cost claim set forth in Exhibit DJC-20. See Exh. DJC-20, pp. 3-17 of 49. For the numerous reasons discussed below, it is evident that those projections do not serve as a reasonable measure of future retail market values.

(1) Design Flaws

The first and foremost problem with Duquesne's RFP in the present context is that it was a wholesale transaction. Exh. RBW-15, p. 5, ¶4; Lahtinen, Tr. 739:11-21. Thus, the RFP sales prices necessarily would understate retail market prices and understate the price Duquesne could obtain by selling its own power in a competitive retail market. Thus, the RFP sales price does not constitute evidence of an amount that "may not be recoverable [by Duquesne] in a competitive electric generation market" in disregard of the requirement of Section 2803 of the Act.

Further, Dr. Weisenmiller's testimony shows in any event that Duquesne's RFP was designed to provide the result Duquesne needed -- a low estimate of the market value of electricity that would serve to maximize Duquesne's stranded cost claim. As Dr. Weisenmiller showed, Duquesne conducted its RFP for just a tiny fraction of its entire power needs, *i.e.*, the sale of a minimum of 50 MWs of firm power for a one-year period and a minimum of 100 MWs of firm power for an eight-year period. However, prices resulting from an auction of those minimal quantities of power cannot be reflective of the value of the whole market for Duquesne's energy in 1998 or in the years through 2005. HSS/ARI Statement No. 1 at 27. In fact, to claim that a solicitation for 50 MWs of electricity (or even 500 MWs) could act as a surrogate for all the power needs of Duquesne, let alone the

Western Pennsylvania region, or be reflective of prices on the PJM and/or ECAR regions is suspect on its face. Consider that 50 MW represents only 2% of peak demand in Duquesne's service territory, and 0.05% in ECAR. HSS/ARI Statement No. 1 at 27:10-11.

At best, the RFP measures the *incremental* generating costs of incremental output from existing generation that has already been committed, similar to the system lambdas.[8] These incremental costs do not include any "start-up," or "no load," variable O&M costs, much less any of the "to go" or "going forward" costs, such as fixed O&M costs, capital additions, or fixed fuel costs. An examination of Duquesne's own costs amply proves the point.

Duquesne has testified that its unbundled *total* costs of generation are over $60/MWh, with those total costs including essentially sunk costs (*e.g.*, the return on and return of equity in the plant) and expected variable costs. Exh. RBW-11. Duquesne also has estimated its "*to go*" or "*going forward*" costs for these generating units as between $23.3/MWh and $35.9/MWh on a 5-year levelized basis. Exh. RBW-12.

Generally, in a competitive market a firm only would commit to sales at prices at least covering its "to go" costs. HSS/ARI Statement No. 1 at 29:2-4. Thus, most firms typically would not sell unlimited quantities of a product for $18/MWh, the weighted average price for the one-year sale under Duquesne's RFP, if it would cost them significantly more to produce such power on a "going forward" basis. Rather, plants with higher operating costs would be shut-down. As supply decreases, the market price will increase to higher levels sufficient to attract either operation of the

[8]The "*system lambda*" reflects the incremental costs to operate the marginal plant on the Duquesne system to produce a small quantity of additional power, which is typically the incremental fuel charge. For example, Duquesne's system lambda at 75% capacity factor was approximately $18/MWh in 1996. *See* Exh. RBW-13.

shut-in units or construction of new capacity. *Id.* at 29:10-18. Thus, if Duquesne's RFP truly were designed to establish market value for electricity in Duquesne's service area, the RFP suffered fatal design flaws that disqualify its use for establishing a benchmark.

(2) Limited Terms and Conditions Of The RFP

The terms and conditions contained in Duquesne's RFP also were of a nature that they disqualified the RFP results from setting a valid measure of market value. Those terms and conditions: (1) reduced the number of potential buyers, and (2) reduced the price bid by the limited number of bidders that actually participated in the process.

As Dr. Weisenmiller pointed out, in the real world of power purchasers, a power purchaser would have bid on Duquesne's RFP only to the extent that it specifically required one year or eight years of power starting on January 1, 1998. HSS/ARI Statement No. 1 at 30:8-9. However, Duquesne's RFP did not contain any flexibility to accommodate differing power purchaser's needs with respect to the length of the purchase terms. Exh. RBW-14. Thus, the universe of potential bidders was reduced to those needing power for exactly one year or eight years, with no flexibility in bidding to account for, for example, the total economic value of a bid for five years combined with another entity's bid for the remaining three years of the eight-year term. Accordingly, potential bidders not interested in power for a one or eight-year term would not have contributed any competitive effect on the price.

Moreover, to increase bids in the RFP, Duquesne would have had to increase options available to power purchasers. HSS/ARI Statement No. 1 at 30:18-21. However, Duquesne's RFP did just the opposite -- it decreased options associated with the power solicitation. *Id.* at 30:21-22.

Clearly, selling a specific product without any options to modify it would reduce the number of potential purchasers.

In addition, Duquesne's actions with respect to bids indicate that Duquesne was not interested in maximizing the number of bidders. For instance, Duquesne rejected a bid submitted by facsimile even though the facsimile was hand-delivered to Duquesne on a timely basis. Exh. RBW-15. That bid for the one-year term was $20.00/MWh or $1.84/MWh higher than the weighted average of the two accepted bids. *Id.* at 60235. Further, the bid submitted for the eight year sales arrangement was higher on a net present value basis than the winning bid. HSS/ARI Statement No. 1 at 31:19-21. Accordingly, it is apparent that Duquesne's interest in conducting the RFP was not to maximize the value of the offer accepted.

(3) Transmission Limitations

Duquesne also successfully lowered the end-results of the RFP by including numerous transmission limitations. For example, page two of the RFP solicitation flatly warned potential bidders that Duquesne "is not responsible for procuring the necessary transmission and ancillary services on Duquesne's transmission system to resell the power . . . ." Duquesne Statement No. 7, Exh. RAI-4, page 2 of 54; *see also* Duquesne Statement No. 7 at 11:7-10 ("Under the RFP, purchasers were required to secure transmission service over the Duquesne transmission system. Therefore, the bid prices that Duquesne solicited relate solely to the value of Duquesne's firm power at the generating station, not the cost of delivering that power (*e.g.*, transmission charges).") Thus, a potential bidder in the RFP would have had to decrease its bid to adjust for inclusion of transmission charges. The bids offered therefore would have been reduced by a bidder's estimation of transmission charges. *Id.* Also, a bidder would have needed to purchase transmission under

Duquesne's open access tariff, including ancillary services, as well as any transmission access in place in the control areas into/through which this power is being delivered. HSS/ARI Statement No. 1 at 32:18-21. Thus, the net effect of this limitation was to reduce the amount bid for the electricity.

(4) Take-or-Pay Implications

The take-or-pay provision in the RFP also shows that the winning bids do not reflect the actual price that would have been paid on a net basis. Under the RFP, a winning bidder effectively would have committed to paying 75% of the winning bid price regardless how much power could be delivered to its market. *See* Exh. RBW-14 at 7-8. Thus, a successful bidder would have been aware that it was committing to pay for the power associated with the RFP regardless of whether it actually took delivery of all the power under the contract. Thus, for example, if a bidder agreed to pay $19/MWh with a 75% take or pay clause, but only expected to be able to take the power 50% of the time, the resulting effective price of the power would be $28.5/MWh (before transmission and ancillary service charges). HSS/ARI Statement No. 1 at 36:18-21. Combining this "take-or-pay" factor consideration with transmission charges indicates that the real costs of the power to a potential purchaser would be much higher than its bid for the power. Accordingly, a bidder additionally would have reduced its bid to account adequately for this take-or-pay clause. *Id.* at 36:15-16.

In conclusion, the results of Duquesne's RFP were pre-determined by the very nature of Duquesne's solicitation, and were designed to understate the real value of electric power in Duquesne's service territory. As such, it was unreasonable for Schnitzer to use the RFP results as a starting point for his 1999-2005 price projections. One last point perhaps demonstrates that fact conclusively. Ironically, that point was provided in testimony that Duquesne itself offered in the December hearings.

As rejoinder testimony, Duquesne's witness Lahtinen described certain adjustments Duquesne would make to future RFP results to set customer generation credits ("CGCs") under Duquesne's proposal. Duquesne Statement No. 5 - Rejoinder at 2:1-6. He acknowledged that Duquesne would make those adjustments to try to take the RFP results from a wholesale to a retail level. Lahtinen, Tr. 728:13- 729:5. Nonetheless, neither Lahtinen in the context of calculating CTCs, nor Schnitzer in the context of trying to forecast future competitive retail market prices made any adjustment to the RFP results to account for a bidder's overhead or profit margin. Further, Schnitzer's decision to apply a 200 basis point risk adjustment was not intended to, nor did it, cure that problem. Moreover, the 200 basis point adjustment was arbitrary and unreasonably low in any event. Schnitzer himself acknowledged that average risk premiums rise to 300 basis points because spot prices, on average, in certain developed energy markets are higher than futures prices. Schnitzer, Tr. 423:25- 424:10. But as Duquesne's Treasurer, Mr. Clayton, acknowledged, "[t]here's not a futures [electric] market that's well established." Clayton, Tr. 248:2. Thus, one might reasonably expect that a risk premium higher than 300 basis points would more accurately have reflected the risk adjustment required to determine a spot market price from Duquesne's RFP results. Of course, "[t]he higher the risk premium, the higher the spot price would be." Schnitzer, Tr. 425:18-19. As such, it is clear that Schnitzer did not even apply an appropriate risk premium that would have adjusted Duquesne's RFP results to reflect an appropriate spot market wholesale price let alone a competitive retail price. Given that fact, it simply is not credible to claim that Duquesne's incremental wholesale auction of power is even remotely reflective of a retail price that Duquesne might expect to prevail in its market. As such, Schnitzer's 1999-2005 price projections that are based upon the RFP results simply are not credible.

(ii) Input Assumptions (2006-2026)

Just as the starting point for Schnitzer's 1999-2005 price projections was unreasonably low, Schnitzer committed the same error with respect to his post-2005 price projections. As a starting point for projecting post-2005 prices, Schnitzer assumed that the technology of choice in 2006 would be gas-fired combined cycle units ("CCs"), and he assumed a range of estimates of capital costs for those units allegedly based upon a review of industry data. Duquesne Statement No. 3 at 26:6-8 and 28:3-4. Based upon those capital cost assumptions and other assumptions that are set forth in his Exhibits MMS-2 and MMS-3, Schnitzer assumed that the cost of entry for newly constructed generating units in 2006 would range from a low case estimate of $34/MWh (2006$) to a high case estimate of $44/MWh (2006$). *Id.* at 27:12-13. In calculating Duquesne's stranded cost claim in Exhibit DJC-20, Duquesne's witness Clayton relied upon the prices Schnitzer derived from his low case estimate to calculate $1.9 billion in stranded costs that Duquesne now claims as of January 1, 1999. Duquesne Statement No. 2R at 12:3-21; *see also* Exh. DJC-20, pp. 3-17 of 49. As will be shown below, however, Schnitzer's capital cost assumptions for CC units on which that stranded cost claim is based, as well as other key assumptions made by Schnitzer, are unreasonably low and not supportable.

As can be seen in Exhibit MMS-2, Schnitzer assumed capital costs for CC units of $395/kW (2005$) and $500/kW (2005$), respectively, for his low and high case estimates. Translated to 1996 dollars, Schnitzer's capital cost estimates would be $316/kW and $400/kW. Schnitzer, Tr. 438:7-439:22. Schnitzer claimed that those capital cost assumptions were based upon his review of industry data. Duquesne Statement No. 3 at 28:3-4. In his rebuttal testimony, Schnitzer further sought to justify his estimates by asserting that "a review of Gas Turbine World . . . indicates that

. . . *installed* costs are now quoted as low as $318 to $380 per kW." Duquesne Statement No. 3R at 22:7-11 (emphasis added). The Gas Turbine World edition that Schnitzer was referring to was for 1997. Schnitzer, Tr. 440:5-9. In 1997 dollars, using Schnitzer's assumed 2.5% inflation rate, his price estimates would be $324/kW and $410/kW, respectively. A review of data from Gas Turbine World 1996 and 1997 editions irrefutably impeaches Schnitzer's claim that his capital cost estimates are reasonable.

It first is appropriate to compare Schnitzer's capital cost assumptions to prices for CC units as reported in the 1996 edition of Gas Turbine World. HSS/ARI obtained those data from Schnitzer in response to an interrogatory in which Schnitzer provided data that he apparently did not rely upon. *See* HSS/ARI Cross Examination Exh. 3. In the one page table of data that Schnitzer provided, prices for the 28 CC units listed ranged in price from a high of $1200/kW to a low of $403/kW. *Id.* Thus, Schnitzer was forced to agree that his assumed capital cost in his *high* case was lower than every price listed in the 1996 Gas Turbine World report. Schnitzer, Tr. 439:20-440:3. A review of the data also shows, as was confirmed by Schnitzer, that the smaller the net plant output of a unit, the higher the price per kW, a fact that was consistent with Schnitzer's understanding, as well. Schnitzer, Tr. 436:2-16. The data also show that whereas the smaller units were listed with budget prices in a range from approximately $60 million to $120 million, the largest, lowest price per kW units were significantly more expensive on an absolute basis, having budget prices of $200 million to $350 million. HSS/ARI Cross Examination Exh. 3. Thus, the data show that many of the lower cost units on the page (in terms of absolute costs) have prices per kW in a range from $500/kW to $800/kW, as compared to Schnitzer's *high* case estimate of only $400/kW. *Id.* Thus, in every respect, the data from the 1996 Gas Turbine World report categorically demonstrate that Schnitzer's

capital cost assumptions (high as well as low), which are the foundation of his post-2005 price projections, are totally unsupported.

Schnitzer's defense of his estimates was based upon data in the 1997 Gas Turbine World report and his claim that prices dropped significantly from 1996 to 1997. *See. e.g.*, Duquesne Statement No. 3R at 22:7-11 and Tr. 440:10-14. However, the 1997 Gas Turbine World report just further impeaches Schnitzer's credibility.

The 1997 Gas Turbine World report is HSS/ARI Cross Examination Exhibit 10. Unlike the one-page excerpt of the 1996 report that is included in HSS/ARI Cross Examination Exhibit 3, HSS/ARI Cross Examination Exhibit 10 contains the entire report concerning pricing of CC units. Read as a whole, the report is extremely revealing.

For one thing, the report sets forth prices for a total of 56 CC units, thus including units with substantially smaller net plant output than were set forth in the one-page excerpt that comprised HSS/ARI Cross Examination Exhibit 3. Of the 28 units listed on page 24 of the report, prices per kW ranged from a high of $1000/kW to a low of $612/kW in 1997 dollars as compared to Schnitzer's high case assumption of a $410/kW (1997$). Further, the absolute price for those units ranged from just $2.2 million to $58.5 million.

On page 26 of the report, only 11 of the 28 units listed had prices lower than Schnitzer's high case estimate of $410/kW(1997$), and only one unit had a price lower than his low case estimate of $324(1997$). In general, the 11 units with prices lower than Schnitzer's high case estimate carry the highest absolute prices ranging from approximately $100 million to $260 million. Further, the net plant output on those units range from approximately 260 MW to 760 MW, as compared to the lower absolute cost units listed in the report as a whole that, in general, have net plant output ranging

from just 7.9 MW to approximately 180 MW. Moreover, according to Schnitzer, the lowest cost per kW unit listed in the report, the only one that has a lower price per kW than Schnitzer's low case estimate, is the state of the art design. Schnitzer, Tr. 440:21-441:9. Its net plant output is rated at 757.5 MW.

Thus, to accept Schnitzer's assumed capital cost estimates, which are the most critical input assumption to his post-2005 price projections, one would have to accept a premise that in all instances new plant construction will consist of the largest output, highest absolute cost units, and that smaller, lower absolute cost CC units will not be sold. In other words, in his high case estimate (which forms the basis for Duquesne's stranded cost calculation of $1.537 billion), one would have to assume installation of one of 11 units to the total exclusion of the 45 other CC units listed in the report, regardless of the plant output needed to serve incremental load at any given time. And, in his low case estimate (which forms the basis for Duquesne's $1.916 billion stranded costs claim) one would have to assume installation of the one state of the art unit with capacity of approximately 760 MW and an absolute cost of $240 million to the total exclusion of the 55 other CC units listed in the report, regardless of the plant output needed to serve incremental load at any given time. In other words, Schnitzer's estimates assume that new generation plants would not be sized to market requirements and funds always would be available for the purchase of the state of the art equipment costing hundreds of millions of dollars. The proposition is absurd on its face and disqualifies his analysis from being accorded any level of credibility.

But, that being said, there is even a more critical mistake in Schnitzer's presentation. Schnitzer testified that his cost estimates are "installed costs" that would include items such as "interconnection with the electric grid, an initial stocking of spares and materials and supplies and

a fuel supply interconnection . . . cost of land." Schnitzer, Tr. 431:16-433:22. He further testified that "[w]e relied on the number of sources which quote, fundamentally installed costs . . . ." *Id.* at 433:14-15. And, again, in his rebuttal testimony, he expressly stated that the 1997 Gas Turbine World report that he claimed justifies his capital cost estimates "indicates that . . .. *installed* costs are now quoted as low as $318 to $380 per kW." Duquesne Statement No. 3R at 22:8-11 (emphasis added).

But, Schnitzer was wrong and could not have been more in error on this point. The 1997 Gas Turbine World report expressly states that:

> These turnkey price levels, as noted, are for 'plain vanilla' plant equipment and services. Extended site work such as co-generation process steam or utility plant tie-ins are not covered, nor are extensive buildings, nor are a large inventory of operational spares such as combustor baskets, blades and vanes, etc.
>
> *Also not included are the indirect, or so-called 'soft costs' that can significantly increase the overall project budget costs.*[9] These would include interest during construction, financing and legal fees, licensing and permitting, insurance and bonding, workman's compensation, sales tax, extensive inland freight, owner's cost and overhead , and finally, project contingency funds.

HSS/ARI Cross Examination Exh. 10 at 22 (emphasis added).

Thus, when Mr. Schnitzer claimed that his capital cost estimates were as "installed," he was wrong. As a consequence, his unreasonably low capital cost assumptions, which are the major input that drives his post-2005 price projections, neither are credible or even usable as a starting point for projecting future prices for use in this proceeding. Nonetheless, to be comprehensive, HSS/ARI will

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[9] Schnitzer was not familiar with the term "soft costs." Schnitzer, Tr. 431:22-23. Thus, it is not surprising that he excluded those costs from his estimates.

discuss a few additional points that show that the other major input assumptions Schnitzer used in projecting post-2005 prices also were unreasonable and designed to derive prices that would substantially understate prices that are likely to prevail.

(6) Overly Optimistic Gas Price Projections

Because Schnitzer assumed that the technology of choice in 2006 would be natural gas-fired combined cycle units, his forecast of natural gas prices was a critical factor in his post-2005 price projections of electricity. HSS/ARI Statement No. 1 at 125:2-8; Schnitzer, Tr. 447:10-11. Obviously, the lower his forecast of natural gas prices, the lower his forecast of electric prices. The evidence clearly shows that Schnitzer's forecast of natural gas prices was unreasonably low and without foundation.

As Dr. Weisenmiller pointed out, there were two primary flaws in Schnitzer's analysis that discredit his forecast of natural gas prices. First, Schnitzer assumed a wellhead gas price forecast that is low by comparison to other existing forecasts. Second, Schnitzer used a gas transportation rate that is unrealistically low. HSS/ARI Statement No. 1 at 125:15-18.

With respect to his forecast of wellhead prices, the sole source that Schnitzer used as a basis for that forecast were "quotes for forward prices through 2005 for gas delivered to Henry Hub in Louisiana." Duquesne Statement No. 3, at 26:14-15. As can be seen from Exhibit RBW-49 and HSS/ARI Cross Examination Exhibit 5, the "quotes" consisted of nothing more than a letter from an over-the-counter securities brokerage firm concerning futures prices at Henry Hub. However, Schnitzer made no investigation to compare the quoted prices to current natural gas prices at Henry Hub. Schnitzer, Tr. 452:12-20. And, his forecast, in fact, does not take into account significant upward movement in recent Henry Hub prices. HSS/ARI Cross Examination Exh. 6, p.3; Schnitzer,

Tr. 455:16-18. Thus, the underlying source "data" for Schnitzer's price forecast is remarkably shallow.

Further, the price forecast Schnitzer developed is low compared to virtually all other sources. Schnitzer's forecast basically is flat in nominal terms, in the range of $2.20 to $2.60 per MMBtu. Exh. MMS-3. Thus, as Dr. Weisenmiller explained, because that projection is stated in nominal terms, it implies that real fuel prices, *i.e.*, that take inflation into account, *decrease* in each year at approximately the rate of inflation through 2026. HSS/ARI Statement No. 1 at 126:3-5. That is an unreasonably low assessment when compared to projections by other sources, including Duquesne, itself.

For instance, Dr. Weisenmiller reviewed publicly available natural gas wellhead forecasts released by EIA, WEFA, DRI and GRI. Exhibit RBW-50. Over the period 1995 to 2015, all of those forecasts predict real increases in the price of natural gas, ranging from 0.1 to 2.5%/year. HSS/ARI Statement No. 1 at 126:10-11. And, in Duquesne's latest Integrated Resource Plan ("IRP"), filed September 1996 and updated May 1997, Duquesne used a natural gas price escalation rate of 4.9%/year. HSS/ARI Statement No. 1 at 128:7-10 Thus, Schnitzer's natural gas forecast not only is unreasonably low *vis-a-vis* the forecasts of forecasting organizations, it is even far below Duquesne's own forecast officially on file with the Commission.

But, if Schnitzer's forecast of wellhead prices was unreasonably low, he compounded the unreasonableness of his delivered price forecast by assuming a transportation rate that is at odds with fact. To determine a transportation rate to get natural gas to delivery points in ECAR, Schnitzer relied upon a handwritten note he received from Columbia Energy Services, an affiliate of Columbia Gas Transmission. Schnitzer, Tr. 457:19-458:4. Based upon the handwritten document, Schnitzer

assumed a 24¢ transportation rate to transport natural gas from Henry Hub to the market area. Schnitzer, Tr. 457:6-10. That differential is set forth in Exhibit MMS-3.

However, the transportation rate does not even begin to capture a reasonable price for the transportation of natural gas. For one thing, the document on its face notes that CNG, another interstate pipeline that supplies transportation to the Duquesne market, "trades .06-.09 higher than TCO."[10] HSS/ARI Cross Examination Exh. 7. Further, depending upon which column Schnitzer used for his estimate, he might have been relying upon a "best guess" in any event. *Id.* Equally important is the fact that Schnitzer did not account for all the transportation rates that would have to be paid to get the gas from Henry Hub to the market area. As Schnitzer admitted, to get gas from Henry Hub *via* the Columbia system would require transportation on both Columbia Gulf and Columbia Transmission which have separate tariffs under which they transport gas. Schnitzer, Tr. 460:3-461:7. While it was Schnitzer's belief that the handwritten note he relied upon was intended to account for transportation from the Gulf Coast to ECAR, he made no attempt to compare the quoted amount to tariffed rates. Similarly, although he acknowledged that a number of interstate pipelines serve the region, he did not examine the tariff sheets for any of those pipelines to compare them to his handwritten quote. Schnitzer, Tr.,462:6-464:17; *see also* HSS/ARI Cross Examination Exh. 8. Schnitzer also assumed without foundation that the same delivered gas cost would apply to all potential generating units throughout the U.S., thus ignoring the reality that transportation costs for new resources likely will vary from region to region and therefore vary for different generating units, depending on location. HSS/ARI Statement No. 1 at 127:15-19.

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[10]TCO stands for Columbia Gas Transmission. Schnitzer, Tr. 459:5-10.

Based upon the obvious shortcomings in Schnitzer's analysis, Dr. Weisenmiller examined historical differentials between wellhead and Midwest citygate prices to compare those data to Schnitzer's transportation charge estimate of a mere 24¢/ MMBtu. He found that those differentials averaged in the $0.50 to $1.00/MMBtu range, or 2.5 to five times Schnitzer's best guess transport rate. *Id.* at 128:1-5.

Given this record, it cannot be concluded other than that Schnitzer's delivered gas price forecast, like the whole of his study, is no more than a back of the envelop projection that was conducted in an unreasonable manner and which severely understates likely future gas costs, the effect of which is to produce an unreasonably low forecast of future electric prices as well.

(ii) Overly Optimistic Inflation Assumptions

Another factor that resulted in Schnitzer forecasting unreasonably low market prices was his overly optimistic prediction of future inflation rates. His assumptions regarding inflation are important for number of reasons.

As Dr. Weisenmiller testified, lower inflation rates mean that components of market-clearing prices rise more slowly, and hence market-clearing prices increase more gradually, than with a higher presumed inflation rate. HSS/ARI Statement No. 1 at 129:3-14. All of the cost components of a *new* generation facility are exposed to the effects of inflation. *Id.* Thus, the rate of inflation directly affects the entirety of such new capacity. In contrast, existing plants' costs include amounts which already were expended, are kept on the books at historical costs, and, thus, are not affected to the same degree by a change in future rates of inflation as are new facilities. *Id.* As a result, lower inflation rates lead to lower costs for new facilities and reduce the resulting market-clearing prices from new facilities placed in operation to satisfy increased demand. *Id.* Thus, an unrealistically low

projection of inflation can create an artificially depressed market-clearing price projection, in turn inflating stranded costs. Schnitzer's assumption of a 2.5% inflation rate clearly was used and intended to produce that result.

Schnitzer assumed that inflation of 2.5%/yr would be in effect during the entirety of the period which Duquesne used for purposes of calculating claims stranded costs, *i.e.*, until 2026. *See* Exhs. MMS 2, 3, and 4; *see also* Exh. DJC-20. However, there is no reasoned basis for his assumption. In fact, it appears that even Schnitzer was not prepared to defend it. In response to a request for "all sources relied by Duquesne to justify its presumed 2.5% inflation factor," Schnitzer stated that he used a 2.5% inflation factor because Mr. Clayton used a 2.5% inflation factor. Exh. RBW-52. Thus, Schnitzer apparently made no independent evaluation to determine the viability of a key assumption in his forecast. However, the assumption of inflation rates has a direct impact on the outcome of his forecast. *See* Exhs. MMS-3 and 4 (Notes). Further, the use of a 2.5% inflation rate for a period in excess of 25 years clearly understates the likely effects of inflation.

As Dr. Weisenmiller testified, he independently reviewed the U.S. Department of Commerce's price deflator data complied for nearly seventy years. He compared Duquesne's forecasts of inflation to the gross *domestic* product price deflator ("GDPPD"), which is closely related to the GNPPD and has become the more common measure of general inflation. HSS/ARI Statement No. 1 at 130:9-16. He found that the average level of the GDPPD during the last twenty five years (1972-1996) has been 4.64%/yr. *Id.* During the last 50 years the average has been 4.2%/year. *Id.* Those historical measures of inflation exceed Duquesne's projection by more than 60%. *See* Exh. RBW-53. Moreover, Dr. Weisenmiller found that during the last 50 years, the GDP price deflator never has increased on average at a rate of 2.5% or less annually for a twenty-five year

proposed distribution rates to assume future capital additions of 10% less than forecast by Duquesne. *See* PECO Order, *mimeo* at 82.

Further, relying upon *Green v. Pa. Pub. Util. Comm'n.*, 473 A.2d 209; 81 Pa. C.S. 55 (1984), the Commission has held that it should disallow expenses projected more than 12 months after a rate case test year. *Pennsylvania Pub. Util. Comm'n. v. Pennsylvania Power & Light Co.*, 67 PUR 4th 30, 50-51 (1985). As a result, particularly given the lack of any evidence to support Duquesne's projected expenditures, it also is appropriate for the Commission to disregard Duquesne's distribution related projections in their entirety and assume a declining rate base that would result from straight line depreciation. To do otherwise would assume without foundation that Duquesne will make certain expenditures that it has not shown are known and measurable. It also would place Duquesne in a position (particularly in the out years as it depreciates existing plant) to extract a return on equity well in excess of the 11.5% return it claims to be requesting.

**H. Conclusion**

For the reasons set forth above, Duquesne's distribution-related rate base should be reduced to eliminate 50% of the net book value associated with Duquesne's 1987-96 distribution-related capital expenditures of $473 million that never have been shown to be just and reasonable. Further, Duquesne's 1996 test year distribution-related rate base should be reduced to reflect a declining rate base through the year 2005 consistent with the effect of straight line depreciation.

## IV. TRANSITION OR STRANDED COSTS

### A. Overview of Stranded Cost Valuation and Recovery Approaches

#### 1. Introduction

The Customer Choice Act requires the Commission to determine the amount of stranded cost recovery that is just and reasonable. 66 Pa. C. S. §§ 2804(13), 2804(14); PECO Order, *mimeo* at 63-64. To determine the amount of recovery ultimately found to be just and reasonable, the Commission must first identify the level of stranded costs that "actually exist" pursuant to the definition of "transition or stranded costs" provided in the Act. PECO Order at 64. Section 2803 of the Act defines "transition or stranded costs" as follows:

> [a]n 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.

66 Pa. C. S. § 2803. Duquesne thus has the "burden to prove, based on substantial evidence in the record, that each [stranded cost] request would recover the net present value of the unmitigated, net, known and measurable generation related expense within the definition of stranded costs." PECO Order at 68. Moreover, Duquesne has the "burden to prove that such costs would have been recoverable under traditional regulation but will not be recoverable in a competitive market." *Id.* Duquesne has failed to meet its burdens.

Duquesne's stranded cost claim inextricably is tied to its proposal to maintain its current rates. Duquesne claims an entitlement to maintain those rates based upon Section 2804(4)(v) of the Customer Choice Act which states:

> If an electric distribution utility rolls its energy cost rate into base rates at a combined level that does not exceed its combined level of such rates which have been approved by the Commission as of the effective date of this chapter, the utility shall not be required to reduce its capped rates below the capped level . . . *if* [1] *the Commission determines that any excess earnings achieved under the cap are being utilized to mitigate transition or stranded costs for the benefit of ratepayers or [2] to offset other known and measurable cost increases that would be recoverable under traditional ratemaking but are not included within the capped rates.*

66 Pa. C.S. § 2804(4)(v) (emphasis added). Duquesne claims an entitlement to the rate floor protection of that provision based upon Duquesne's proposal to accelerate depreciation and amortization of its generation assets by $1.7 billion through 2005 ostensibly for the purpose of mitigating stranded costs. However, Duquesne also insists that its stranded costs are not known and measurable at this time. Thus, Duquesne proposed that a valuation of its generation assets and stranded costs, if any, should take place in 2003 based upon a premise that public sources of objective market data will be available at that time to satisfy the known and measurable standard. Duquesne Statement No. 3 at 46:14-16; Duquesne Statement No. 1 at 14:17-18. As a result, Duquesne would have the Commission grant Duquesne authority to charge a CTC to recover stranded costs prior to an actual determination that Duquesne, in fact, has stranded costs to recover. As will be demonstrated below, however, Duquesne has not proven even on a preliminary basis that it has any stranded costs in the first place. Therefore, Duquesne has failed to carry its evidentiary burden that would serve as support for its request to accelerate amortization and depreciation. Thus, Duquesne's request to accelerate amortization and depreciation by $1.7 billion represents nothing more than an attempt by Duquesne to manufacture an inflated cost of service to attempt to justify the maintenance of exorbitant rates and collection of amounts in excess of those to which Duquesne is entitled under traditional ratemaking methodologies.

2. Duquesne's Approach

When Duquesne originally filed its application, Duquesne stated that it had to make two showings to establish a *prima facie* case to justify its rate proposals. First, Duquesne had to show that "a mechanism exists to ensure that if revenues under [its proposed] rate cap are greater than the normal cost of service, these 'excess earnings' will be used to mitigate transition or stranded costs . . . ." Duquesne Statement No. 3, at 22:6-8. Second, Duquesne stated that it "must demonstrate that stranded costs still remain in 2006 even after the 'excess earnings' mitigation . . . ." *Id.* at 22:14-15. Duquesne claimed to make the latter showing by claiming that as of December 31, 2005, it "likely [will] have remaining stranded costs of $8 to $582 million . . . ." Duquesne Statement No. 2 at 29:20-21. But, how did Duquesne derive its estimated range of claimed post-2005 remaining stranded costs? It did so by relying upon computer-generated market price projections notwithstanding Duquesne's compelling criticisms of those projections. Moreover, in Duquesne's case, those price projections are best characterized as nothing more than back of the envelop calculations.

Using a simple computer program of his own design, Duquesne's witness Schnitzer calculated future retail market prices in some cases out to the year 2026. To derive those price projections, Schnitzer input unreasonable assumptions into his computer and made unreasonably modest adjustments to Duquesne's summer 1997 wholesale RFP results, the net effect of which was to produce unreasonably low projections of future retail market prices. Based upon those price projections, Duquesne calculated revenues that it claimed it would gain (1) through 2005 and (2) through the retirement dates of its various plants (Schnitzer's projected market prices times projected plant output). *See* Exh. DJC-3. Duquesne then calculated its costs of operation assuming acceleration of $1.7 billion in amortization and depreciation. Based upon those cumulative data,

Duquesne claimed that as of 2006, its plants would have a net book value of $535 million, but market value only in a range of a negative $47 million to a positive $527 million depending upon whether Schnitzer's low or high price projections were used to determine the future operating margins for Duquesne's plants. It was Duquesne's comparison of those projected market values to net book investment as of December 31, 2005 that served as the basis for Duquesne's initial claim that, notwithstanding its acceleration of amortization and depreciation, Duquesne likely would have remaining stranded costs ranging from $8 million to $582 million as of January 1, 2006. Duquesne Statement No. 2 at 29:20-22; Exh. DJC-3 at 1.[6] Thus, it was the claimed market values derived principally from Schnitzer's price predictions that served as the basis for Duquesne's initial requests (1) that it be provided authorization to accelerate depreciation and amortization by $1.7 billion allegedly to mitigate stranded costs that Duquesne claimed otherwise would remain in 2006 and (2) that it be granted authorization to continue to charge its current rates.

However, Duquesne miscalculated the cost side of its equation. Duquesne was forced to admit that it had overstated its projected costs and that, as a result, as of January 1, 2006, Duquesne might not have any stranded costs at all. *See* Exh. RBW-1. Duquesne's corrected calculations, in fact, showed that its generation assets might have positive market value of as much as $233 million assuming Schnitzer's high case price projection. *See* Attachment A to Exh. RBW-1; *see also* Duquesne Statement No. 2R at 9:8-10. Thus, as HSS/ARI's witness, Dr. Weisenmiller, pointed out in his direct testimony, Duquesne would have flunked its own test for qualifying for its rate proposals based upon its own revised data, *i.e.*, Duquesne could not demonstrate that it was likely

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[6] $535 million (net book value)- $527 million (market value) = $8 million in stranded costs. $535 million (net book value)- ($47) million (market value) = $582 million in stranded costs.

that stranded costs still would remain in 2006 even after the excess earnings mitigation. HSS/ARI Statement No. 1 at 6:8-15.

As a consequence, in its rebuttal testimony, Duquesne modified its claim. In its rebuttal testimony, Duquesne claimed for the first time that it would have quantifiable stranded costs as of January 1, 1999 in the amount of $1.916 billion. Duquesne Statement No. 2R at 12:18-21; Duquesne Statement No. 3R at 2:12-14. The $1.916 billion claim was derived using a similar formulation to that described above. Again, Duquesne used Schnitzer's unreasonably modest adjustments to wholesale RFP results and computer-generated price projections to calculate plant revenues. Duquesne's witness Clayton then used those unreasonably low price forecasts to calculate projected plant margins, *i.e.*, the difference between projected plant revenues (Schnitzer's projected market prices times projected plant output) and Duquesne's unreasonably high projections of the costs of operating its plants. Clayton then netted those plant margins against the net book value of Duquesne's generation plants, costs Duquesne claims it will experience independent of operation of the plants and decommissioning costs to determine stranded costs of $1.9 billion that Duquesne now claims it will have as of January 1, 1999. Duquesne Statement No. 2R at 12; Exh. DJC-20, page 1 of 49.

To understand the significance of Schnitzer's price projections to Duquesne's claim, it is important to understand that Duquesne's $1.916 billion stranded cost claim is based upon Schnitzer's *low* case price projections. If one merely adjusts for Schnitzer's *high* case projection (another unreasonably low price forecast), Duquesne's stranded costs would be $1.537 billion, or $379 million lower than Duquesne's claim. And that almost $400 million reduction does not take into account a host of other adjustments that should be made that would raise Schnitzer's high case price

projections or reduce Duquesne's cost projections and claimed regulatory assets. Thus, an almost $400 million swing is produced by a mere penny per kWh swing in price projections used to determine revenues commencing in 2006. *See* Duquesne Statement No. 2R at 12; Exh. DJC-20 at p. 1 of 49. As a consequence, it is obvious that the significance of mere pennies in price projections is the difference between a stranded cost claim of almost $2 billion and a finding that Duquesne has no stranded costs at all. Thus, it is beyond dispute that the accuracy of Schnitzer's price projections are critical in determining whether Duquesne has the right to have the Commission approve any of Duquesne's proposals. More specifically, the accuracy of Schnitzer's price projections are critical in determining whether Duquesne has the right to charge a CTC while deferring an actual stranded cost calculation until some future time date.

3. HSS/ ARI Approach

HSS/ARI's approach to this case was to examine Duquesne's stranded cost claims in three different ways. As a first step, HSS/ARI examined the evidence that Duquesne relies upon as the basis for its stranded cost claim, both in terms of price and cost projections. The purpose of that examination was to determine whether, in HSS/ARI's view, Duquesne's evidence establishes that Duquesne has stranded costs. The need for that first step evaluation flows directly from the assignment to Duquesne of the evidentiary burden in this case.

A second way in which HSS/ARI approached this case was to examine documents produced by Duquesne itself in discovery and circumstances other than those relied upon by Duquesne. The purpose of examining such documents and circumstances was to determine whether there is evidence of the market value of Duquesne's generation assets other than the evidence relied upon by Duquesne.

HSS/ARI's third approach to this case was to examine facts and circumstances concerning Duquesne's mitigation efforts, or lack thereof.

As a result of its examination of the evidence, HSS/ARI has concluded that Duquesne failed to meet its burden and, thus, should be denied any stranded cost recovery. Duquesne failed to meet that burden for two principal reasons. First, its stranded cost claim, in all its variations, depends upon Schnitzer's computer-generated price projections. As HSS/ARI will discussed herein, the evidence shows that those price projections were derived in a manner to assure an unreasonably low result, the net effect of which was to maximize and overstate Duquesne's potential stranded costs. Thus, HSS/ARI agree with Duquesne's President and CEO that Schnitzer's computer-generated price projections are inconsistent with the known and measurable standard. Marshall, Tr. 83:1-84:5. The second principal reason that Duquesne failed to meet its burden was that it inflated its cost projections, as well. Thus, by understating projected market prices and overstating projected operating costs, Duquesne inappropriately maximized and grossly overstated its stranded cost claim. *See* Clayton, Tr. 265:17 - 266:14. HSS/ARI will discuss the evidence that demonstrates the flaws in Duquesne's price and cost projections in sections IV. B.3 and IV. B.4, respectively.

HSS/ARI also has concluded that there is substantial evidence relevant to an assessment of the market value of Duquesne's generation assets that Duquesne did not put in the record in this case. HSS/ARI will show in section IV. B.3(c), that actual valuations of Duquesne's assets performed by Duquesne and its consultants mere months before the filing of Duquesne's application show that Duquesne's assets have positive market value. Those studies, as well as evidence of market value demonstrated by actual market transactions, including, but not limited to, Duquesne's sale of its interest in the Ft. Martin plant, show that Duquesne has no stranded costs at all.

Finally, HSS/ARI will discuss evidence that demonstrates that notwithstanding Duquesne's claims that it intends to fully mitigate its claimed stranded costs, Duquesne has failed to undertake actions that could have or would mitigate any stranded costs Duquesne claims to have.

4. Conclusion

In view of Duquesne's failure to establish that it has net know and measurable stranded costs, substantial evidence that shows that Duquesne's generation assets have positive market value and Duquesne's failure to properly mitigate any stranded costs it claims to have, HSS/ARI request that the Commission:

(1) deny Duquesne's request to accelerate depreciation and amortization;

(2) deny Duquesne recovery of any amount claimed to be a stranded cost;

(3) deny Duquesne the right to charge its customers a CTC; and

(4) deny Duquesne's request to have its potential stranded costs reexamined through a final valuation conducted at some future date.

## B. Generation-Related Stranded Costs (Recovery Pursuant To Section 2808(3))

1. Introduction

Duquesne has failed to demonstrate that it will have any generation-related stranded costs as of January 1, 1999, nor has Duquesne demonstrated that it will have stranded costs as of January 1, 2006. Clearly, therefore, it has failed to satisfy the "known and measurable" standard imposed by the Customer Choice Act as a predicate to a utility recovering *any* stranded costs.

2. Net Book Value

(a) Total Net Book Value

Duquesne claims a total net book value of $918 million for its generation assets. Exh. DJC-10. Based upon certain adjustments set forth in Exhibit DJC-10, Duquesne would increase its net book value up to $1.236 billion to reflect certain generation-related expenses. Duquesne also claims to have $374.45 million in generation-related regulatory assets.

HSS/ARI do not dispute Duquesne's calculation of a net book investment in generation-related assets is $1.236 billion. However, HSS/ARI do object to the use of that net book value for purposes of establishing the generation component of Duquesne's rates or Duquesne's potential stranded costs. HSS/ARI will discuss here their objection to the inclusion in Duquesne's net book value the costs of capital additions made during the period 1986 to 1997. HSS/ARI will discuss in subsection (c), below, issues related to Phillips and Brunot Island costs. HSS/ARI will discuss its position with respect to Duquesne's regulatory asset claims in Section IV. E.

With respect to Duquesne's generation-related capital additions constructed since 1986, as was discussed previously in the context of Duquesne's distribution rates, it must be remembered that Duquesne has chosen not to file a rate case since 1986. Duquesne Statement No. 4 at 22:15-20. Thus, as is the case with Duquesne's distribution-related capital expenditures, the Commission has not reviewed any of the capital or other expenditures that Duquesne made associated with its generation cost of service for over a ten-year period. As a consequence, Duquesne also had the burden of establishing that generation related capital expenditures over that ten-year period were just and reasonable to the extent that those costs are subsumed within Duquesne's current generation rate structure. *Pennsylvania Pub. Util. Comm'n v. Philadelphia Electric,* 1990 Pa. PUC Lexis at p* 54-

57; 66 Pa. C.S. § 315 (A). However, as in the case of its distribution-related capital expenditures, Duquesne also produced no evidence to support its past generation-related capital expenditures.

Duquesne's FERC Form 1 reports show that between 1987 and 1996, exclusive of expenditures related to Beaver Valley 2 and Duquesne's initial capital expenditure of $743 million for Perry Unit 1, Duquesne made generation-related capital expenditures of approximately $382 million. HSS/ARI Statement No. 1, at 55-56. Again, given that Duquesne made no attempt to introduce any evidence that might suggest that its past generation-related capital expenditures were just and reasonable, it is within the Commission's authority to order a total disallowance of the $382 million in claimed generation-related capital expenditures. *Pennsylvania Pub. Util. Comm'n. v. Equitable.*, 57 Pa. PUC at 444 n.37, 66 Pa. C.S. § 1301. Nonetheless, to balance the interests as previously discussed, HSS/ARI recommend a 50% disallowance of that amount.[7]

(c) Recovery of Phillips and Brunot Island Costs

For purposes of considering Duquesne's stranded cost claim, its net book investment of $1.236 billion in generation-related assets also should be reduced to eliminate the net book investment associated with the Phillips and Brunot Island cold reserve capacity. That reduction would be in the amount of $106;800,000. Duquesne Statement No. 4:12-14. There are three principal reasons why that reduction is appropriate.

As Dr. Weisenmiller explained in unrebutted testimony:

> Duquesne took the units out of rate base, and placed them in cold reserve, in 1986 for two essential reasons. First, due to a 50 percent loss of its industrial load, Duquesne did not need the units to operate to serve its market. Exh. RBW-60 (p. 3, Paragraph 10). Second, and

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[7] *See also* n.5, *supra.*

> as a result of the first factor, Duquesne sought authority from the Commission to cold reserve the units, and take them out of rate base, as part of an "overall corporate program to substantially reduce costs *and reduce revenue requirements*." *Id.* at 5 (emphasis added).

HSS/ARI Statement No 1S at 24:14-20. Therefore, as Dr. Weisenmiller pointed out, if the costs of the cold reserved units are stranded, they are not stranded as a result of Pennsylvania's legislation that restructures the electric industry. Rather, to the extent any costs are stranded, they were stranded by Duquesne's loss of its industrial market over ten years ago. *Id.* at 24:20-25:2. In that circumstance, there is no reason why Duquesne's ratepayers should be forced to pay for Duquesne's investment in facilities due to the passage of legislation that has no impact on Duquesne's use or non-use of the cold reserved plants.

A second reason that Duquesne's net book investment should be reduced by the net book investment in Phillips and Brunot Island for purposes of considering Duquesne's stranded cost claim is that Duquesne should be held to the representations it made to the Commission in 1986 when it requested authority to cold reserve the units. As Exhibit RBW-60 shows, when Duquesne asked to take the units out of rate base, it did so to reduce its costs and its revenue requirement for the benefit of ratepayers. Exh. RBW-60 at 3 ¶11. Further, there was a presumption that the units would not be brought back into service unless and until there was a need to operate the units to serve Duquesne's market. *Id.* at 4, ¶13. As a result, as Dr. Weisenmiller testified, Duquesne should be held to its 1986 promise to reduce costs and not be permitted to shift financial responsibility to Duquesne's 21st century customers for the failure of load growth to materialize after 1979. HSS/ARI Statement No. 1S at 25:9-13. Indeed, that result is all the more appropriate given that Duquesne has no plans to

return the facilities to utility service. Duquesne Statement No. 2R at 32:23-25; *see also* Exh. DJC-21, pp. 24-26 of 141.

(d) Conclusion

For the foregoing reasons, for purposes of considering Duquesne's stranded cost claim, its net book investment should be considered to be $938 million to reflect the elimination of Duquesne's net book investment in the cold reserve portions of the Brunot Island and Phillips facilities and 50% of Duquesne's generation-related capital expenditures between 1986 and the present, none of which ever have been shown to be just and reasonable.

3. Market Value

(a) Introduction

In considering Duquesne's calculation of market value, *i.e.*, the key component of its stranded cost calculation, the testimony of Duquesne's President and CEO is critical. Mr. Marshall expressly stated in his direct testimony, and he confirmed during his cross-examination, that Duquesne believes that administrative (a code word for computer-generated) projections of future market prices are inconsistent with the known and measurable standard. Duquesne Statement No. 1 at 14:7-14; Tr. 61:1-4. And, when asked: is it Duquesne's position that it is entitled to $ 1.9 billion in stranded costs based upon an administrative determination, Mr. Marshall answered:

> We are saying that based on the best information we have today, that we estimate the number at 1.9 billion.
> [However, w]e do not believe that the method is adequate to determine a stranded cost calculation today.

Marshall, Tr. 75:13-21.

Similarly, Mr. Marshall testified:

based on the best information we have, what would the number be, it is 1.9, but when you say, do I support it, I don't support it . . . .

Marshall, Tr. 79:4-7.

And, Mr. Marshall responded as follows when asked:

Q. are Mr. Schnitzer's price projections -- now I'll make it very specific to the period 2006 and beyond -- are those price projections consistent with the known and measurable standard?
A. No.

Marshall, Tr. 82:21-25. Thus, given Mr. Marshall's testimony, the following discussion largely is academic because there can be no dispute that Duquesne has not submitted a stranded cost calculation that even Duquesne believes satisfies the statutory standard. Nonetheless, it is worthwhile to review the evidence to see how Duquesne determined a market value that by any reasonable assessment must be determined to grossly understate the real value of Duquesne's generation facilities.

(b) Market Price Projections

(i) Forecasting Methodology

Duquesne relied upon the testimony of Michael Schnitzer to determine market prices for purposes of its stranded cost calculations (both as of January 1, 1999 and as of December 31, 2005). In determining his market price projections, Schnitzer used a two-step process. First, he estimated future market prices for the period 1998 through 2005 using as a starting point for his analysis the results of Duquesne's summer 1997 Request for Proposals ("RFP"). Second, he input into a computer a handful of assumptions to derive price projections for the period 2006 until the book retirement date of each of Duquesne's generation facilities.

HSS/ARI will show that the adjustments Schnitzer made to Duquesne's RFP results were woefully inadequate to transform the result of Duquesne's wholesale auction of an incremental quantity of power into a price that reasonably is reflective of future retail market prices. Thus, Schnitzer's 1998-2005 price projections unreasonably understate likely prices at the retail level. HSS/ARI also will show that the assumptions that Schnitzer relied upon for his computer-generated post-2005 price projections also were designed to understate unreasonably future market prices. However, there is a preliminary matter that should be discussed that demonstrates why Schnitzer's price forecasts so grossly understate likely future market prices.

It is critical to understand that the starting points Schnitzer used in his two sets of calculations were unreasonably low, thus ensuring an understatement of future market prices. With respect to Schnitzer's 1998-2005 price projections, it is critical to understand why the prices paid in Duquesne's RFP were so low and, thus, wholly inadequate for purposes of estimating future market prices. And, with respect to Schnitzer's post-2005 price projections, it is critical to understand that his starting point, his estimates of the capital costs of combined cycle units, are so low that they are at odds not only with reality, but even with the specific source that Schnitzer touts as support for his estimates. Focusing on those two points in the following discussion demonstrates why even Duquesne and Mr. Marshall cannot support Schnitzer's price projections.

(ii) Input Assumptions (1998-2005)

There are two key input assumptions for Schnitzer's price projections for the period 1998 through 2005. His first assumption was that the results of Duquesne's RFP could serve as the starting point for the projection. The second was his apparent assumption that a mere 200 basis point risk adjustment factor would be adequate to solve for an equivalent all-hours retail spot price stream. *See* Duquesne Statement No. 3 at 34:4-7. As will be discussed below, Schnitzer's use of Duquesne's RFP results demonstrably was designed to produce an artificially low forecast of market prices.

Duquesne conducted an RFP in June of 1997 in which it offered to sell in a wholesale transaction a minimum of 50 MWs of firm power for a one-year period and a minimum of 100 MWs (with a maximum of 500 MW) of firm power for an eight-year period commencing on January 1, 1998. Duquesne Statement No. 7 at 6:4-8. According to Mr. Marshall, Duquesne sent out 300 notices to marketers around the country to participate in the RFP. Marshall, Tr. 156:8-12. Nonetheless, Duquesne received only five bids for the one-year sale and only eleven bids on the eight-year sale. *Id.* at 9:15-16; Irvin, Tr. at 823:18-20. That level of non-participation alone should have suggested to Mr. Schnitzer that there were factors at play that disqualified the RFP results from being a meaningful measure of market value.

In any event, as a result of the RFP, contracts were executed with two entities for a total sale of 50 MWs for one year, and with one entity for a sale of 100 MWs for the eight year period. Duquesne Statement No. 7 at 10:1-2. The weighted average price for the one-year sale was $18.16/MWh and the winning bid for the eight year sale was $20.19/MWh on a "nominal" levelized basis. *Id.* at 10:19 to 11:1. Mr. Schnitzer then adjusted those numbers, using his 200 basis point risk premium adjustment, an assumed inflation rate of 2.5% and assumed risk free and risk-adjusted

discount rates to determine a 1998 spot market price of 1.78¢/kWh. *See* Exh. MMS-4. Schnitzer projected that price out to 2005 based upon the assumptions previously discussed. *Id.* Those price projections then were used to calculate the 1999-2005 portion of Duquesne's stranded cost claim set forth in Exhibit DJC-20. See Exh. DJC-20, pp. 3-17 of 49. For the numerous reasons discussed below, it is evident that those projections do not serve as a reasonable measure of future retail market values.

(1) Design Flaws

The first and foremost problem with Duquesne's RFP in the present context is that it was a wholesale transaction. Exh. RBW-15, p. 5, ¶4; Lahtinen, Tr. 739:11-21. Thus, the RFP sales prices necessarily would understate retail market prices and understate the price Duquesne could obtain by selling its own power in a competitive retail market. Thus, the RFP sales price does not constitute evidence of an amount that "may not be recoverable [by Duquesne] in a competitive electric generation market" in disregard of the requirement of Section 2803 of the Act.

Further, Dr. Weisenmiller's testimony shows in any event that Duquesne's RFP was designed to provide the result Duquesne needed -- a low estimate of the market value of electricity that would serve to maximize Duquesne's stranded cost claim. As Dr. Weisenmiller showed, Duquesne conducted its RFP for just a tiny fraction of its entire power needs, *i.e.*, the sale of a minimum of 50 MWs of firm power for a one-year period and a minimum of 100 MWs of firm power for an eight-year period. However, prices resulting from an auction of those minimal quantities of power cannot be reflective of the value of the whole market for Duquesne's energy in 1998 or in the years through 2005. HSS/ARI Statement No. 1 at 27. In fact, to claim that a solicitation for 50 MWs of electricity (or even 500 MWs) could act as a surrogate for all the power needs of Duquesne, let alone the

Western Pennsylvania region, or be reflective of prices on the PJM and/or ECAR regions is suspect on its face. Consider that 50 MW represents only 2% of peak demand in Duquesne's service territory, and 0.05% in ECAR. HSS/ARI Statement No. 1 at 27:10-11.

At best, the RFP measures the *incremental* generating costs of incremental output from existing generation that has already been committed, similar to the system lambdas.[8] These incremental costs do not include any "start-up," or "no load," variable O&M costs, much less any of the "to go" or "going forward" costs, such as fixed O&M costs, capital additions, or fixed fuel costs. An examination of Duquesne's own costs amply proves the point.

Duquesne has testified that its unbundled *total* costs of generation are over $60/MWh, with those total costs including essentially sunk costs (*e.g.*, the return on and return of equity in the plant) and expected variable costs. Exh. RBW-11. Duquesne also has estimated its "*to go*" or "*going forward*" costs for these generating units as between $23.3/MWh and $35.9/MWh on a 5-year levelized basis. Exh. RBW-12.

Generally, in a competitive market a firm only would commit to sales at prices at least covering its "to go" costs. HSS/ARI Statement No. 1 at 29:2-4. Thus, most firms typically would not sell unlimited quantities of a product for $18/MWh, the weighted average price for the one-year sale under Duquesne's RFP, if it would cost them significantly more to produce such power on a "going forward" basis. Rather, plants with higher operating costs would be shut-down. As supply decreases, the market price will increase to higher levels sufficient to attract either operation of the

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[8]The "*system lambda*" reflects the incremental costs to operate the marginal plant on the Duquesne system to produce a small quantity of additional power, which is typically the incremental fuel charge. For example, Duquesne's system lambda at 75% capacity factor was approximately $18/MWh in 1996. *See* Exh. RBW-13.

shut-in units or construction of new capacity. *Id.* at 29:10-18. Thus, if Duquesne's RFP truly were designed to establish market value for electricity in Duquesne's service area, the RFP suffered fatal design flaws that disqualify its use for establishing a benchmark.

(2) Limited Terms and Conditions Of The RFP

The terms and conditions contained in Duquesne's RFP also were of a nature that they disqualified the RFP results from setting a valid measure of market value. Those terms and conditions: (1) reduced the number of potential buyers, and (2) reduced the price bid by the limited number of bidders that actually participated in the process.

As Dr. Weisenmiller pointed out, in the real world of power purchasers, a power purchaser would have bid on Duquesne's RFP only to the extent that it specifically required one year or eight years of power starting on January 1, 1998. HSS/ARI Statement No. 1 at 30:8-9. However, Duquesne's RFP did not contain any flexibility to accommodate differing power purchaser's needs with respect to the length of the purchase terms. Exh. RBW-14. Thus, the universe of potential bidders was reduced to those needing power for exactly one year or eight years, with no flexibility in bidding to account for, for example, the total economic value of a bid for five years combined with another entity's bid for the remaining three years of the eight-year term. Accordingly, potential bidders not interested in power for a one or eight-year term would not have contributed any competitive effect on the price.

Moreover, to increase bids in the RFP, Duquesne would have had to increase options available to power purchasers. HSS/ARI Statement No. 1 at 30:18-21. However, Duquesne's RFP did just the opposite -- it decreased options associated with the power solicitation. *Id.* at 30:21-22.

Clearly, selling a specific product without any options to modify it would reduce the number of potential purchasers.

In addition, Duquesne's actions with respect to bids indicate that Duquesne was not interested in maximizing the number of bidders. For instance, Duquesne rejected a bid submitted by facsimile even though the facsimile was hand-delivered to Duquesne on a timely basis. Exh. RBW-15. That bid for the one-year term was $20.00/MWh or $1.84/MWh higher than the weighted average of the two accepted bids. *Id.* at 60235. Further, the bid submitted for the eight year sales arrangement was higher on a net present value basis than the winning bid. HSS/ARI Statement No. 1 at 31:19-21. Accordingly, it is apparent that Duquesne's interest in conducting the RFP was not to maximize the value of the offer accepted.

(3) Transmission Limitations

Duquesne also successfully lowered the end-results of the RFP by including numerous transmission limitations. For example, page two of the RFP solicitation flatly warned potential bidders that Duquesne "is not responsible for procuring the necessary transmission and ancillary services on Duquesne's transmission system to resell the power . . . ." Duquesne Statement No. 7, Exh. RAI-4, page 2 of 54; *see also* Duquesne Statement No. 7 at 11:7-10 ("Under the RFP, purchasers were required to secure transmission service over the Duquesne transmission system. Therefore, the bid prices that Duquesne solicited relate solely to the value of Duquesne's firm power at the generating station, not the cost of delivering that power (*e.g.*, transmission charges).") Thus, a potential bidder in the RFP would have had to decrease its bid to adjust for inclusion of transmission charges. The bids offered therefore would have been reduced by a bidder's estimation of transmission charges. *Id.* Also, a bidder would have needed to purchase transmission under

Duquesne's open access tariff, including ancillary services, as well as any transmission access in place in the control areas into/through which this power is being delivered. HSS/ARI Statement No. 1 at 32:18-21. Thus, the net effect of this limitation was to reduce the amount bid for the electricity.

(4) Take-or-Pay Implications

The take-or-pay provision in the RFP also shows that the winning bids do not reflect the actual price that would have been paid on a net basis. Under the RFP, a winning bidder effectively would have committed to paying 75% of the winning bid price regardless how much power could be delivered to its market. *See* Exh. RBW-14 at 7-8. Thus, a successful bidder would have been aware that it was committing to pay for the power associated with the RFP regardless of whether it actually took delivery of all the power under the contract. Thus, for example, if a bidder agreed to pay $19/MWh with a 75% take or pay clause, but only expected to be able to take the power 50% of the time, the resulting effective price of the power would be $28.5/MWh (before transmission and ancillary service charges). HSS/ARI Statement No. 1 at 36:18-21. Combining this "take-or-pay" factor consideration with transmission charges indicates that the real costs of the power to a potential purchaser would be much higher than its bid for the power. Accordingly, a bidder additionally would have reduced its bid to account adequately for this take-or-pay clause. *Id.* at 36:15-16.

In conclusion, the results of Duquesne's RFP were pre-determined by the very nature of Duquesne's solicitation, and were designed to understate the real value of electric power in Duquesne's service territory. As such, it was unreasonable for Schnitzer to use the RFP results as a starting point for his 1999-2005 price projections. One last point perhaps demonstrates that fact conclusively. Ironically, that point was provided in testimony that Duquesne itself offered in the December hearings.

As rejoinder testimony, Duquesne's witness Lahtinen described certain adjustments Duquesne would make to future RFP results to set customer generation credits ("CGCs") under Duquesne's proposal. Duquesne Statement No. 5 - Rejoinder at 2:1-6. He acknowledged that Duquesne would make those adjustments to try to take the RFP results from a wholesale to a retail level. Lahtinen, Tr. 728:13- 729:5. Nonetheless, neither Lahtinen in the context of calculating CTCs, nor Schnitzer in the context of trying to forecast future competitive retail market prices made any adjustment to the RFP results to account for a bidder's overhead or profit margin. Further, Schnitzer's decision to apply a 200 basis point risk adjustment was not intended to, nor did it, cure that problem. Moreover, the 200 basis point adjustment was arbitrary and unreasonably low in any event. Schnitzer himself acknowledged that average risk premiums rise to 300 basis points because spot prices, on average, in certain developed energy markets are higher than futures prices. Schnitzer, Tr. 423:25- 424:10. But as Duquesne's Treasurer, Mr. Clayton, acknowledged, "[t]here's not a futures [electric] market that's well established." Clayton, Tr. 248:2. Thus, one might reasonably expect that a risk premium higher than 300 basis points would more accurately have reflected the risk adjustment required to determine a spot market price from Duquesne's RFP results. Of course, "[t]he higher the risk premium, the higher the spot price would be." Schnitzer, Tr. 425:18-19. As such, it is clear that Schnitzer did not even apply an appropriate risk premium that would have adjusted Duquesne's RFP results to reflect an appropriate spot market wholesale price let alone a competitive retail price.. Given that fact, it simply is not credible to claim that Duquesne's incremental wholesale auction of power is even remotely reflective of a retail price that Duquesne might expect to prevail in its market. As such, Schnitzer's 1999-2005 price projections that are based upon the RFP results simply are not credible.

(ii) Input Assumptions (2006-2026)

Just as the starting point for Schnitzer's 1999-2005 price projections was unreasonably low, Schnitzer committed the same error with respect to his post-2005 price projections. As a starting point for projecting post-2005 prices, Schnitzer assumed that the technology of choice in 2006 would be gas-fired combined cycle units ("CCs"), and he assumed a range of estimates of capital costs for those units allegedly based upon a review of industry data. Duquesne Statement No. 3 at 26:6-8 and 28:3-4. Based upon those capital cost assumptions and other assumptions that are set forth in his Exhibits MMS-2 and MMS-3, Schnitzer assumed that the cost of entry for newly constructed generating units in 2006 would range from a low case estimate of $34/MWh (2006$) to a high case estimate of $44/MWh (2006$). *Id.* at 27:12-13. In calculating Duquesne's stranded cost claim in Exhibit DJC-20, Duquesne's witness Clayton relied upon the prices Schnitzer derived from his low case estimate to calculate $1.9 billion in stranded costs that Duquesne now claims as of January 1, 1999. Duquesne Statement No. 2R at 12:3-21; *see also* Exh. DJC-20, pp. 3-17 of 49. As will be shown below, however, Schnitzer's capital cost assumptions for CC units on which that stranded cost claim is based, as well as other key assumptions made by Schnitzer, are unreasonably low and not supportable.

As can be seen in Exhibit MMS-2, Schnitzer assumed capital costs for CC units of $395/kW (2005$) and $500/kW (2005$), respectively, for his low and high case estimates. Translated to 1996 dollars, Schnitzer's capital cost estimates would be $316/kW and $400/kW. Schnitzer, Tr. 438:7-439:22. Schnitzer claimed that those capital cost assumptions were based upon his review of industry data. Duquesne Statement No. 3 at 28:3-4. In his rebuttal testimony, Schnitzer further sought to justify his estimates by asserting that "a review of Gas Turbine World . . . indicates that

. . . *installed* costs are now quoted as low as $318 to $380 per kW." Duquesne Statement No. 3R at 22:7-11 (emphasis added). The Gas Turbine World edition that Schnitzer was referring to was for 1997. Schnitzer, Tr. 440:5-9. In 1997 dollars, using Schnitzer's assumed 2.5% inflation rate, his price estimates would be $324/kW and $410/kW, respectively. A review of data from Gas Turbine World 1996 and 1997 editions irrefutably impeaches Schnitzer's claim that his capital cost estimates are reasonable.

It first is appropriate to compare Schnitzer's capital cost assumptions to prices for CC units as reported in the 1996 edition of Gas Turbine World. HSS/ARI obtained those data from Schnitzer in response to an interrogatory in which Schnitzer provided data that he apparently did not rely upon. *See* HSS/ARI Cross Examination Exh. 3. In the one page table of data that Schnitzer provided, prices for the 28 CC units listed ranged in price from a high of $1200/kW to a low of $403/kW. *Id.* Thus, Schnitzer was forced to agree that his assumed capital cost in his *high* case was lower than every price listed in the 1996 Gas Turbine World report. Schnitzer, Tr. 439:20-440:3. A review of the data also shows, as was confirmed by Schnitzer, that the smaller the net plant output of a unit, the higher the price per kW, a fact that was consistent with Schnitzer's understanding, as well. Schnitzer, Tr. 436:2-16. The data also show that whereas the smaller units were listed with budget prices in a range from approximately $60 million to $120 million, the largest, lowest price per kW units were significantly more expensive on an absolute basis, having budget prices of $200 million to $350 million. HSS/ARI Cross Examination Exh. 3. Thus, the data show that many of the lower cost units on the page (in terms of absolute costs) have prices per kW in a range from $500/kW to $800/kW, as compared to Schnitzer's *high* case estimate of only $400/kW. *Id.* Thus, in every respect, the data from the 1996 Gas Turbine World report categorically demonstrate that Schnitzer's

capital cost assumptions (high as well as low), which are the foundation of his post-2005 price projections, are totally unsupported.

Schnitzer's defense of his estimates was based upon data in the 1997 Gas Turbine World report and his claim that prices dropped significantly from 1996 to 1997. *See. e.g.*, Duquesne Statement No. 3R at 22:7-11 and Tr. 440:10-14. However, the 1997 Gas Turbine World report just further impeaches Schnitzer's credibility.

The 1997 Gas Turbine World report is HSS/ARI Cross Examination Exhibit 10. Unlike the one-page excerpt of the 1996 report that is included in HSS/ARI Cross Examination Exhibit 3, HSS/ARI Cross Examination Exhibit 10 contains the entire report concerning pricing of CC units. Read as a whole, the report is extremely revealing.

For one thing, the report sets forth prices for a total of 56 CC units, thus including units with substantially smaller net plant output than were set forth in the one-page excerpt that comprised HSS/ARI Cross Examination Exhibit 3. Of the 28 units listed on page 24 of the report, prices per kW ranged from a high of $1000/kW to a low of $612/kW in 1997 dollars as compared to Schnitzer's high case assumption of a $410/kW (1997$). Further, the absolute price for those units ranged from just $2.2 million to $58.5 million.

On page 26 of the report, only 11 of the 28 units listed had prices lower than Schnitzer's high case estimate of $410/kW(1997$), and only one unit had a price lower than his low case estimate of $324(1997$). In general, the 11 units with prices lower than Schnitzer's high case estimate carry the highest absolute prices ranging from approximately $100 million to $260 million. Further, the net plant output on those units range from approximately 260 MW to 760 MW, as compared to the lower absolute cost units listed in the report as a whole that, in general, have net plant output ranging

from just 7.9 MW to approximately 180 MW. Moreover, according to Schnitzer, the lowest cost per kW unit listed in the report, the only one that has a lower price per kW than Schnitzer's low case estimate, is the state of the art design. Schnitzer, Tr. 440:21-441:9. Its net plant output is rated at 757.5 MW.

Thus, to accept Schnitzer's assumed capital cost estimates, which are the most critical input assumption to his post-2005 price projections, one would have to accept a premise that in all instances new plant construction will consist of the largest output, highest absolute cost units, and that smaller, lower absolute cost CC units will not be sold. In other words, in his high case estimate (which forms the basis for Duquesne's stranded cost calculation of $1.537 billion), one would have to assume installation of one of 11 units to the total exclusion of the 45 other CC units listed in the report, regardless of the plant output needed to serve incremental load at any given time. And, in his low case estimate (which forms the basis for Duquesne's $1.916 billion stranded costs claim) one would have to assume installation of the one state of the art unit with capacity of approximately 760 MW and an absolute cost of $240 million to the total exclusion of the 55 other CC units listed in the report, regardless of the plant output needed to serve incremental load at any given time. In other words, Schnitzer's estimates assume that new generation plants would not be sized to market requirements and funds always would be available for the purchase of the state of the art equipment costing hundreds of millions of dollars. The proposition is absurd on its face and disqualifies his analysis from being accorded any level of credibility.

But, that being said, there is even a more critical mistake in Schnitzer's presentation. Schnitzer testified that his cost estimates are "installed costs" that would include items such as "interconnection with the electric grid, an initial stocking of spares and materials and supplies and

a fuel supply interconnection . . . cost of land." Schnitzer, Tr. 431:16-433:22. He further testified that "[w]e relied on the number of sources which quote, fundamentally installed costs . . . ." *Id.* at 433:14-15. And, again, in his rebuttal testimony, he expressly stated that the 1997 Gas Turbine World report that he claimed justifies his capital cost estimates "indicates that . . . *installed* costs are now quoted as low as $318 to $380 per kW." Duquesne Statement No. 3R at 22:8-11 (emphasis added).

But, Schnitzer was wrong and could not have been more in error on this point. The 1997 Gas Turbine World report expressly states that:

> These turnkey price levels, as noted, are for 'plain vanilla' plant equipment and services. Extended site work such as co-generation process steam or utility plant tie-ins are not covered, nor are extensive buildings, nor are a large inventory of operational spares such as combustor baskets, blades and vanes, etc.
>
> *Also not included are the indirect, or so-called 'soft costs' that can significantly increase the overall project budget costs.*[9] These would include interest during construction, financing and legal fees, licensing and permitting, insurance and bonding, workman's compensation, sales tax, extensive inland freight, owner's cost and overhead , and finally, project contingency funds.

HSS/ARI Cross Examination Exh. 10 at 22 (emphasis added).

Thus, when Mr. Schnitzer claimed that his capital cost estimates were as "installed," he was wrong. As a consequence, his unreasonably low capital cost assumptions, which are the major input that drives his post-2005 price projections, neither are credible or even usable as a starting point for projecting future prices for use in this proceeding. Nonetheless, to be comprehensive, HSS/ARI will

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[9] Schnitzer was not familiar with the term "soft costs." Schnitzer, Tr. 431:22-23. Thus, it is not surprising that he excluded those costs from his estimates.

discuss a few additional points that show that the other major input assumptions Schnitzer used in projecting post-2005 prices also were unreasonable and designed to derive prices that would substantially understate prices that are likely to prevail.

(6) Overly Optimistic Gas Price Projections

Because Schnitzer assumed that the technology of choice in 2006 would be natural gas-fired combined cycle units, his forecast of natural gas prices was a critical factor in his post-2005 price projections of electricity. HSS/ARI Statement No. 1 at 125:2-8; Schnitzer, Tr. 447:10-11. Obviously, the lower his forecast of natural gas prices, the lower his forecast of electric prices. The evidence clearly shows that Schnitzer's forecast of natural gas prices was unreasonably low and without foundation.

As Dr. Weisenmiller pointed out, there were two primary flaws in Schnitzer's analysis that discredit his forecast of natural gas prices. First, Schnitzer assumed a wellhead gas price forecast that is low by comparison to other existing forecasts. Second, Schnitzer used a gas transportation rate that is unrealistically low. HSS/ARI Statement No. 1 at 125:15-18.

With respect to his forecast of wellhead prices, the sole source that Schnitzer used as a basis for that forecast were "quotes for forward prices through 2005 for gas delivered to Henry Hub in Louisiana." Duquesne Statement No. 3, at 26:14-15. As can be seen from Exhibit RBW-49 and HSS/ARI Cross Examination Exhibit 5, the "quotes" consisted of nothing more than a letter from an over-the-counter securities brokerage firm concerning futures prices at Henry Hub. However, Schnitzer made no investigation to compare the quoted prices to current natural gas prices at Henry Hub. Schnitzer, Tr. 452:12-20. And, his forecast, in fact, does not take into account significant upward movement in recent Henry Hub prices. HSS/ARI Cross Examination Exh. 6, p.3; Schnitzer,

Tr. 455:16-18. Thus, the underlying source "data" for Schnitzer's price forecast is remarkably shallow.

Further, the price forecast Schnitzer developed is low compared to virtually all other sources. Schnitzer's forecast basically is flat in nominal terms, in the range of $2.20 to $2.60 per MMBtu. Exh. MMS-3. Thus, as Dr. Weisenmiller explained, because that projection is stated in nominal terms, it implies that real fuel prices, *i.e.*, that take inflation into account, *decrease* in each year at approximately the rate of inflation through 2026. HSS/ARI Statement No. 1 at 126:3-5. That is an unreasonably low assessment when compared to projections by other sources, including Duquesne, itself.

For instance, Dr. Weisenmiller reviewed publicly available natural gas wellhead forecasts released by EIA, WEFA, DRI and GRI. Exhibit RBW-50. Over the period 1995 to 2015, all of those forecasts predict real increases in the price of natural gas, ranging from 0.1 to 2.5%/year. HSS/ARI Statement No. 1 at 126:10-11. And, in Duquesne's latest Integrated Resource Plan ("IRP"), filed September 1996 and updated May 1997, Duquesne used a natural gas price escalation rate of 4.9%/year. HSS/ARI Statement No. 1 at 128:7-10 Thus, Schnitzer's natural gas forecast not only is unreasonably low *vis-a-vis* the forecasts of forecasting organizations, it is even far below Duquesne's own forecast officially on file with the Commission.

But, if Schnitzer's forecast of wellhead prices was unreasonably low, he compounded the unreasonableness of his delivered price forecast by assuming a transportation rate that is at odds with fact. To determine a transportation rate to get natural gas to delivery points in ECAR, Schnitzer relied upon a handwritten note he received from Columbia Energy Services, an affiliate of Columbia Gas Transmission. Schnitzer, Tr. 457:19-458:4. Based upon the handwritten document, Schnitzer

assumed a 24¢ transportation rate to transport natural gas from Henry Hub to the market area. Schnitzer, Tr. 457:6-10. That differential is set forth in Exhibit MMS-3.

However, the transportation rate does not even begin to capture a reasonable price for the transportation of natural gas. For one thing, the document on its face notes that CNG, another interstate pipeline that supplies transportation to the Duquesne market, "trades .06-.09 higher than TCO."[10] HSS/ARI Cross Examination Exh. 7. Further, depending upon which column Schnitzer used for his estimate, he might have been relying upon a "best guess" in any event. *Id.* Equally important is the fact that Schnitzer did not account for all the transportation rates that would have to be paid to get the gas from Henry Hub to the market area. As Schnitzer admitted, to get gas from Henry Hub *via* the Columbia system would require transportation on both Columbia Gulf and Columbia Transmission which have separate tariffs under which they transport gas. Schnitzer, Tr. 460:3-461:7. While it was Schnitzer's belief that the handwritten note he relied upon was intended to account for transportation from the Gulf Coast to ECAR, he made no attempt to compare the quoted amount to tariffed rates. Similarly, although he acknowledged that a number of interstate pipelines serve the region, he did not examine the tariff sheets for any of those pipelines to compare them to his handwritten quote. Schnitzer, Tr.,462:6-464:17; *see also* HSS/ARI Cross Examination Exh. 8. Schnitzer also assumed without foundation that the same delivered gas cost would apply to all potential generating units throughout the U.S., thus ignoring the reality that transportation costs for new resources likely will vary from region to region and therefore vary for different generating units, depending on location. HSS/ARI Statement No. 1 at 127:15-19.

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[10]TCO stands for Columbia Gas Transmission. Schnitzer, Tr. 459:5-10.

Based upon the obvious shortcomings in Schnitzer's analysis, Dr. Weisenmiller examined historical differentials between wellhead and Midwest citygate prices to compare those data to Schnitzer's transportation charge estimate of a mere 24¢/ MMBtu. He found that those differentials averaged in the $0.50 to $1.00/MMBtu range, or 2.5 to five times Schnitzer's best guess transport rate. *Id.* at 128:1-5.

Given this record, it cannot be concluded other than that Schnitzer's delivered gas price forecast, like the whole of his study, is no more than a back of the envelop projection that was conducted in an unreasonable manner and which severely understates likely future gas costs, the effect of which is to produce an unreasonably low forecast of future electric prices as well.

(ii) Overly Optimistic Inflation Assumptions

Another factor that resulted in Schnitzer forecasting unreasonably low market prices was his overly optimistic prediction of future inflation rates. His assumptions regarding inflation are important for number of reasons.

As Dr. Weisenmiller testified, lower inflation rates mean that components of market-clearing prices rise more slowly, and hence market-clearing prices increase more gradually, than with a higher presumed inflation rate. HSS/ARI Statement No. 1 at 129:3-14. All of the cost components of a *new* generation facility are exposed to the effects of inflation. *Id.* Thus, the rate of inflation directly affects the entirety of such new capacity. In contrast, existing plants' costs include amounts which already were expended, are kept on the books at historical costs, and, thus, are not affected to the same degree by a change in future rates of inflation as are new facilities. *Id.* As a result, lower inflation rates lead to lower costs for new facilities and reduce the resulting market-clearing prices from new facilities placed in operation to satisfy increased demand. *Id.* Thus, an unrealistically low

projection of inflation can create an artificially depressed market-clearing price projection, in turn inflating stranded costs. Schnitzer's assumption of a 2.5% inflation rate clearly was used and intended to produce that result.

Schnitzer assumed that inflation of 2.5%/yr would be in effect during the entirety of the period which Duquesne used for purposes of calculating claims stranded costs, *i.e.*, until 2026. *See* Exhs. MMS 2, 3, and 4; *see also* Exh. DJC-20. However, there is no reasoned basis for his assumption. In fact, it appears that even Schnitzer was not prepared to defend it. In response to a request for "all sources relied by Duquesne to justify its presumed 2.5% inflation factor," Schnitzer stated that he used a 2.5% inflation factor because Mr. Clayton used a 2.5% inflation factor. Exh. RBW-52. Thus, Schnitzer apparently made no independent evaluation to determine the viability of a key assumption in his forecast. However, the assumption of inflation rates has a direct impact on the outcome of his forecast. *See* Exhs. MMS-3 and 4 (Notes). Further, the use of a 2.5% inflation rate for a period in excess of 25 years clearly understates the likely effects of inflation.

As Dr. Weisenmiller testified, he independently reviewed the U.S. Department of Commerce's price deflator data complied for nearly seventy years. He compared Duquesne's forecasts of inflation to the gross *domestic* product price deflator ("GDPPD"), which is closely related to the GNPPD and has become the more common measure of general inflation. HSS/ARI Statement No. 1 at 130:9-16. He found that the average level of the GDPPD during the last twenty five years (1972-1996) has been 4.64%/yr. *Id.* During the last 50 years the average has been 4.2%/year. *Id.* Those historical measures of inflation exceed Duquesne's projection by more than 60%. *See* Exh. RBW-53. Moreover, Dr. Weisenmiller found that during the last 50 years, the GDP price deflator never has increased on average at a rate of 2.5% or less annually for a twenty-five year

period. *Id.* at 130:18 to 131:2. Dr. Weisenmiller also found that serious outbreaks of inflation occur periodically. During just the last half century, the U.S. experienced significant inflation in 1946-47 (11-12% increases in the annual GDPPD), 1951 (6.8%), 1974-75 (9-9.5%) and 1979-81 (8.5-9.4%). *Id.* at 131:4-8.

As a result, it is fair to assume that Schnitzer's presumed inflation rate is highly improbable and not credible. Further evidence of that is Duquesne's own estimate of inflation taken from its July 1, 1996 IRP for the period through 2001. Duquesne, itself, assumes inflation ranges from 3.1 to 3.9%/yr for the consumer price index ("CPI"). *See* Exh. RBW-53. As Dr. Weisenmiller testified, CPI measures consumer goods and uses fixed weights, and has historically been higher than broader inflation indices such as the GNPPD or GDPPD. *Id.* at 132:7-11. The historical difference between the CPI and the GDPPD for the 25 years ending 1991 is 0.3%/yr. *Id.* Thus, Duquesne's IRP inflation forecast, once adjusted, translates into a GDPPD rate in the 2.8%/yr to 3.6%/yr range. *Id.* Obviously, Schnitzer's 2.5%/yr. assumption appears unreasonably low compared even to Duquesne's own prognostications.

(7) Pollution Control Costs

The final factor that skewed Schnitzer's forecast producing unreasonably low price projections was an input that Schnitzer did not make, *i.e.*, to reflect pollution control costs in his forecasts. As Dr. Weisenmiller pointed out, to an extent, Duquesne incorporated anticipated $NO_X$ control costs into projected capital expenditures for its plants in considering its future costs of operating existing plants. HSS/ARI Statement No. 1 at 133:2:7. The $NO_X$ control costs were based on the requirements of the Clean Air Act Amendments ("CAAA") and Acid Rain Rule requirements. *See* Exh. RLN-6. The CAAA Title IV Phase I regulatory requirements are not the only regulatory

program that aims to control $NO_X$ emissions from Duquesne's power plants. HSS/ARI Statement No. 1 at 133:9-19. Dr. Weisenmiller testified that there are several overlapping current and proposed regulations to control $NO_X$ emissions from power plants in Pennsylvania. *Id.* at 133:9-19. Those regulations, which Duquesne has not even considered, could vastly increase $NO_X$ control costs beyond those incurred by the CAAA Title IV Phase I requirements. Dr. Weisenmiller also testified that depending on the stringency of the other regulatory programs relative to the CAAA Title IV Phase I requirements, the current emissions of Duquesne's plants, and the ultimate form that the proposed actions take in terms of limits on $NO_X$ emissions these costs could increase significantly. For example, the CAAA Title IV Phase II requirements are more stringent than the Phase I requirements. Dr. Weisenmiller testified that this might imply that a utility would have to incur additional expenses to reduce emissions. *Id.* at 134:11-21. He further testified that, because some $NO_X$ regulations are only at the proposal stage, it is difficult to determine with certainty whether future regulations would increase $NO_X$ control costs beyond those incurred by the CAAA Title IV Phase I requirements. In general, though, future $NO_X$ regulations are expected to be more stringent than both the Title IV Phase I and Phase II regulations. *See id.*

Duquesne's failure to fully account for pollution control costs leads to particularly misleading results because its assumed technology, CCs as gas fired units, will be impacted to a greater extent by $NO_X$ emission costs than will Duquesne's existing coal-fired plants. Id. at 135:5-8. Thus, Schnitzer inappropriately raised the spread between Duquesne's projected costs and its expected revenues based on his price predictions by not accounting for $NO_X$ emissions costs on both sides of the equation.

(ii) OCA and DII Input Assumptions

As is evident from the foregoing, a principal reason that Schnitzer's price forecasts are unreasonably low is that his starting point, *i.e.*, assumed capital costs for CC units, was unreasonably low. Unfortunately, OCA's and DII's price forecasts suffer from the identical shortcoming.

As can be seen in OCA Statement No. 2 at 9:2-3, OCA's witness Smith assumed capital costs of $560/KW (1997$) for CC units and $296/kW (1997$) for combustion turbine ("CT") units. DII's witness Falkenberg assumed similar capital costs, *i.e.*, $595/kW per CC units and $300/kW for CT units. DII Statement No. 2 at 25:11-12. While OCA's and DII's assumed capital costs for CC units are higher than those assumed by Mr. Schnitzer, both OCA's and DII's estimates are still low and fail to account for various factors that both Smith and Falkenberg indicated could result in higher capital costs than those contained in their analyses. Further, there are other shortcomings in the Smith and Falkenberg analyses that will be discussed below.

A critical problem with both Smith's and Falkenberg's estimate of capital costs is explained by OCA witness Smith, himself. Mr. Smith testified that:

> I expect that many new units will incur higher capital costs than I have assumed, due to one or more of the following factors:
>
> - Greater interest costs during construction;
> - Increase in CC/CT equipment costs from current market conditions, which represent a historical low point;
> - Greater land costs (my figures reflect a generic land price from the Electric Power Research Institute's "Technical Assessment Guide");
> - Greater project development costs, representing the "soft costs" needed for the legal, financing, and permitting efforts needed to develop a successful project;

- Non-standardized plant features, reflecting tradeoffs between plant design and capital cost. For example, combined cycle units with the most complex and efficient steam cycles will tend to cost more, as will units with reliability features such as a bypass stack or multiple shaft design. The 1996 Gas Turbine World Handbook (which I used as a source for equipment costs) states: "These turnkey plant price levels, as noted, are for 'plain vanilla' plant equipment and services. Extended site work such as cogeneration process steam or utility plant tie-ins are not covered, nor are extensive buildings, nor a large inventory of operational spares such as combustor baskets, blades and vanes, etc." I have assumed quite competitive reliability (annual availabilities) on the order of 90 percent) and thermal efficiencies (as-operated heatrate of 6,700 BTU/kWh) for new CC units; it is unlikely that these high-performance units will also be the cheapest;

- Selective catalytic reduction ("SCR") equipment for control of NOx emissions on CC units. The turnkey equipment costs underlying my estimate include dry low-NOx burners, but not equipment for catalytic reduction of NOx or $CO_2$ emissions. To the extent that SCR or other control measures are actually required for some or all of the new CC generating units built in PJM, additional capital and operating costs would be required;

- General Plant. My cost estimates treat the CC and CT options as stand-alone facilities, and do not include an allocation of general plant which would presumably be incurred by generating companies in the ECAR market.

Any or all of these factors could increase the cost of new capacity (and therefore market power prices) relative to my analysis.

OCA Statement No. 2 at 9:6-10:16. Thus, Smith's own testimony discredits his own, as well as Falkenberg's, price projections by demonstrating that he and Falkenberg understated the capital cost estimates that serve as the foundation of their price projections.

Another problem with Smith's and Falkenberg's estimates of capital costs is explained by Falkenberg. He cites an article from Electric Utility Week that discusses "serious problems with

advanced combined-cycle and combustion turbine units that have become a major concern with owners, investors and insurers." DII Statement No. 2 at 32:5-6. He states that the article indicates "more than a half-dozen failures are known and General Electric has indicated that some 70 of its units (many not yet installed) required repair and overhaul in the past two years." *Id.* at 32:7-9. Falkenberg further indicates that the article discusses explosions, litigation and increases in the cost of insurance and financing. *Id.* at 9-10.

Notwithstanding that article, neither Mr. Falkenberg nor Mr. Smith, nor Mr. Schnitzer for that matter, made any adjustment to his cost estimate to account for the potential cost increases that could arise from the problems discussed in the article. Further, like Mr. Schnitzer, neither Smith nor Falkenberg provide any justification for their assumptions that per unit costs should be based upon the largest output, most expensive (in absolute terms) units, as opposed to lower output, lower absolute cost units. Again, both Mr. Smith and Mr. Falkenberg, like Mr. Schnitzer, assume that all operators will install the largest output units regardless of market requirements, and that they will be willing to pay $200 million or more for those units, rather than install smaller units that might cost from just $14 million to $100 million. *See* HSS/ARI Cross Examination Exh. 10. Finally, neither Smith nor Falkenberg adequately explain the bases for their assumptions that lower cost CT units (used for peaking purposes -- *see* OCA Statement No. 2 at 8:22-23) should be considered in estimating future market prices.

Thus, OCA's and DII's computer-generated price projections suffer from the most major flaw that infects Duquesne's and Mr. Schnitzer's price projections, as well, *i.e.*, the starting point for their forecasts also assume unreasonably low capital costs for new generation units. As a result, like Mr. Schnitzer's price forecasts, OCA's and DII's market price forecasts are unreasonably low,

the effect of which is an overstatement of Duquesne's potential stranded costs.

(iii) Results

The foregoing discussion demonstrates that Duquesne's computer-generated price projections, and those of the OCA and DII as well, are unreasonably understated, and as such, are not credible as starting points from which to estimate stranded costs that satisfy the known and measurable standard. However, as will be discussed below, there is other evidence of market value in this case that is far superior to Duquesne, OCA's and DII's computer-generated results.

(c) Other Evidence of Market Value

In assessing Duquesne's claim, and OCA's and DII's price projections as well, it is manifest to examine documents obtained from Duquesne reflecting its, and its consultants, valuations of Duquesne's assets. It also is important to assess those valuations in comparison to real market valuations reflected by Duquesne's sale of its interest in the Ft. Martin plant and more recent sales of generation assets that show that large capacity generation plants around the country are being sold above net book value. The conclusion to be reached from that examination is that Duquesne has no stranded costs because its facilities would have positive market value if Duquesne would offer them for sale.

The starting point for this analysis is a review of a study that Duquesne itself performed to assess the value of its assets. In that study, Duquesne considered various scenarios involving the possible sale of its generating assets. Duquesne concluded in the study that the "[s]ale of generating assets can add between $500-$750 million in after tax cash for investing." Exh. RBW-3 at 12. Moreover, the same internal study concluded that "deferring tax [consequences] could double those amounts." *Id.* The study furthermore recognized that the sale of the Cheswick and Elrama units

"shows strong economics." *Id.*

Specifically, Duquesne's study found that sale of the Cheswick and Elrama units would yield purchase premiums of $160 million in a base case scenario. *Id.* at 8. If power sales were to be increased, the purchase premium would rise to $335 million. *Id.* If sales increased and O&M costs were reduced by one-third, the purchase premium for such a sale was approximated at $460 million. *Id.* Earnings per share in Duquesne's study would increase by nearly 50 percent annually by 2003 compared to the business as usual approach. *Id.* In fact, in the same study, Duquesne calculated that it might capture a "purchase premium" of $733 million in addition to net book value on all of its generating assets. *Id.* at 10. In terms of percentages, Duquesne found that it might earn premiums above net book value in a range of 27% to 211%. *Id.* at 9 and 11.

The general import of Duquesne's own internal assessment of the value sales of its facilities would produce is fortified by studies by its consultants. For instance, Metzler & Associates ("Metzler") performed an asset valuation for Duquesne using Duquesne's power price projections ranging from a worst case of $18-20/MWh to a "most likely case" of $27/MWh to a best case of $35/MWh. Exh. RBW-5 at 2. Using those assumptions, Metzler quoted to Duquesne values as high as $225 million for the Cheswick unit and $150 million for Elrama. Exh. RBW-6 (study dated July 15, 1996). In a subsequent study, Metzler increased its price projections up to $264 million for the Cheswick Unit (compared to net book value of $120 million); $224 million for Elrama (net book value $100 million); Brunot Island $112 million (net book value $26 million); and Phillips $140 million (net book value $78 million). Exh. RBW-7 at 3; Duquesne Statement 2, Exh. DJC-3 at 32-38 and Exh. MKO-1C, p.1 of 13. In that more recent study, Metzler also indicated to Duquesne that a third-party sale of generation assets presented the "potential to receive [a] better price." Exh.

RBW-7 at 4.

Thus, Duquesne has received advice from independent consultants hired by Duquesne that a sale of its generating assets would maximize market value. Indeed, Metzler noted that a sale of assets presented a "[h]igher probability of achieving price[s] above book value." Exh. RBW-8 at 4. Similarly, Metzler told Duquesne that the sale of Duquesne's generating assets in a separate "Genco" unit "provides the strategic investor with a much more robust market presence." *Id.* at 5. According to the study, "[p]roceeds of an asset sale can be used to offset nuclear stranded costs with or without a *Genco*." *Id.* at 6. Metzler, in fact, indicated that the value of just four of the Duquesne generating facilities could *exceed* depreciated net book value by more than $657 million. Exh. RBW-9 at 4.

In addition to the Metzler study, in late November 1996, Duquesne received a study of the value of Duquesne's generating assets from the investment banking firm CS First Boston that Duquesne later hired as its advisor in connection with its proposed merger with APS. Exh. RBW-10; Clayton, Tr. 275:16-18.[11] CS First Boston advised that Duquesne could sell five of its generation plants with a total net book value of $450 million for between $827 million and $1.184 billion -- a purchase premium ranging from $377 to $734 million. Exh. RBW-10; HSS/ARI Statement No. 1 at 21, Table III-1.

Another interesting element of the CS First Boston study is that the assumed power price in

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[11] Mr. Clayton denied that Duquesne retained CS First Boston as its merger advisor because of CS First Boston's valuation study. Clayton, Tr. 275:16-276:4. However, Duquesne obviously was impressed with the study. It simply is not credible to argue the opposite, *i.e.*, that Duquesne would have retained CS First Boston as its merger advisor even though Duquesne thought CS First Boston's November 1996 valuation study was grossly inaccurate.

its leveraged cash flow analyses is 2.6¢/kWh, *i.e.* $26/MWh. *See, e.g.*, Exh. RBW-10 at 0053855. The projected power price highlights the artificially low 1.816¢/kWh ($18.16/MWh) price that forms the basis for Schnitzer's price projections.

Thus, studies performed by and for Duquesne present a far different picture concerning the value of Duquesne's generation facilities than the dismal picture Duquesne presents to the Commission in support of Duquesne's exorbitant and unjustified stranded cost claim. The market value estimate derived by Duquesne, its consultants and financial investors also is substantially higher than the market valuations derived from OCA's and DII's computer-generated price forecasts as well. But while Duquesne's, OCA's and DII's computer-generated price forecasts only can be verified on a prospective basis as compared to actual future market prices, there is independent evidence today to verify and corroborate Duquesne's internal conclusions and the conclusions of Metzler and CS First Boston.

The first element of such evidence is Duquesne's own sale of its interest in the Ft. Martin plant. That was a real market transaction, and Duquesne's President and CEO acknowledged that APS' purchase of that interest established the fair market value of the plant at the time of the sale. Marshall, Tr. 71:15-20. Duquesne sold its 50% interest for $169 million -- *four and a half times* the net book value of $37 million. HSS/ARI Statement No. 1 at 22:14-22. Thus, the transaction reflects actual market evidence of a buyer paying a substantial premium for one of Duquesne's own generation assets, an indisputable fact that slightly predates, but nonetheless, is consistent with Duquesne's, Metzler's and CS First Boston's conclusions.

Further, there is more recent evidence that corroborates their conclusions that the sale of generation assets will occur at multiples of net book value. For instance, as Dr. Weisenmiller

discussed in his direct testimony, the New England Electric System ("NEES") recently sold to U.S. Generating Company generation facilities at a price of $1.59 billion -- approximately $500 million more than its $1.1 billion book value, or approximately 1.4 times net book value. HSS/ARI Statement No. 1 at 146:1-2. Similarly, Pacific Gas & Electric Company ("PG&E") and Southern California Edison Company ("SoCal Edison") recently sold generation facilities for approximately $500 million and $1.1 billion, respectively. HSS/ARI Statement No. 1S at 7: 8-17. PG&E's sale was consummated at approximately 1.32 times net book value, and SoCal Edison's facilities sold at 2.65 times net book value. Similarly, Central Maine Power recently concluded the sale of facilities at a substantial premium above net book value.[12] Thus, this actual market evidence fully corroborates Metzler's and CS First Boston's conclusions that there is a market that is willing to pay multiples of net book value to purchase existing generation units.

(d) Conclusion

In performing his analysis in this case, Dr. Weisenmiller compared Schnitzer's projected market price projections with a number of other projections. Exh. RBW-57. In particular, Dr. Weisenmiller compared Schnitzer's price projections to price projections by:

- West Penn in its restructuring filing;
- West Penn in its analysis of its purchase of Duquesne's interest in Ft. Martin;
- CS First Boston and Metzler in their valuation assessments of Duquesne's

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[12] *See Utility FPL Agrees to Purchases to Gain Presence in the Northeast,* Wall St. J., January 7, 1998, at B12. Section 5.408 of the Commission's regulations permits the Commission or the presiding administrative law judge to take official notice or judicial notice of facts. 52 Pa. Code § 5.408(a); *see also Tilghman v. Pennsylvania*, 27 Pa. Commw. 484, 487, 366 A.2d. 966, 967 (Pa. Commw. Ct. 1976), *affd*, 473 Pa. 319, 374, A. 2d. 535, (Pa. 1977) (authorizing judicial notice of newspaper articles).

generation assets;

- EIA, an energy-only market line prepared earlier this year; and
- William Hieronymus for PECO both as originally stated for PECO and adjusted to ECAR using a transmission rate of $6/MWh.

With the exception of the price projection filed by Duquesne's proposed merger partner, West Penn, all of the other projections exceed Duquesne's. Exh. RBW-57. However, as is shown in Section 3(b) above, Duquesne's price projections have no foundation in fact. Further, OCA's and DII's computer-generated alternative calculations suffer from many of the same foundational flaws.

In any event, there is no reason to rely upon any of those forecasts in this case. The best evidence of the market value of Duquesne's generation-related assets comes from Duquesne's financial and strategic planning documents, the valuations performed by Metzler and CS First Boston, and the real market evidence that corroborates the basic conclusions of those valuations, *i.e.*, that Duquesne's generation assets have market value at some multiple of net book value. Thus, it is appropriate to conclude that the evidence shows that Duquesne's facilities have a value in excess of Duquesne's net book investment such that Duquesne has no stranded costs. However, if there is a requirement to derive a stranded cost calculation using a specific price forecast, HSS/ARI submit that the price projection that should be used is that of CS First Boston. Notwithstanding Mr. Clayton's disclaimer, Duquesne must have had faith in the analysis, otherwise it is implausible that Duquesne would have hired CS First Boston as its merger advisor. Thus, if the CS First Boston price projection is used, Duquesne's generation assets would have a positive market value of $481 million (1998$). Exh. RBW-57. That valuation negates Duquesne's stranded cost claim in its entirety, inclusive of its claim relating to regulatory assets.

4. Other Factors Affecting Market Value/Stranded Costs

Based upon the use of the price projections that were used in the CS First Boston study, there is no need to examine a host of other issues that demonstrate that Duquesne's stranded cost claim is overstated. However, it is clear that there are numerous factors, other than Duquesne's vastly understated market value assessment, that led Duquesne to grossly overstate its stranded cost exposure. Thus for completeness of the record, HSS/ARI will address those issues below.

(a) Life Extension

One factor that caused Duquesne to overstate its stranded cost exposure was that Duquesne failed to consider the potential benefits that could result from extending the life of certain plants to create a positive cash flow. It follows as a matter of logic that when low cost plants are operated over longer periods, their below-market costs can offset greater amounts of above-market prices. HSS/ARI Statement No. 1 at 66-67. Thus, sales of electricity from competitive plants (*i.e.*, capable of producing electricity at below market clearing prices) can offset sales from non-competitive plants (those capable of producing electricity only at above market clearing prices). *Id.* at 67:3-12. Accordingly, the longer competitive plants operate, the greater the offset against stranded costs.

Notwithstanding that indisputable fact, in performing its stranded cost calculation, Duquesne assumed that when a facility's costs are fully recovered for ratemaking purposes, the facility will cease operation regardless of the value of its power. *Id.* at 67:16-17. Obviously, many plants continue to operate after the date of full recovery of depreciation. Accordingly, it is not reasonable for Duquesne to calculate its stranded costs based on a scenario that contravenes operating its facilities in a prudent, economically rational fashion. *Id.* at 67:20-22.

Moreover, with respect to operation of a plant after it has been fully depreciated, the portion

of the plant's revenue dedicated to return of invested capital could be devoted to other purposes. *Id.* at 68:3-7. As a result, plants -- both competitive and non-competitive -- could be operated at lower operating costs such that non-competitive plants may, in fact, become competitive and competitive plants would become more competitive, *i.e.*, more effective at offsetting stranded costs. *Id.*

Nonetheless, Duquesne's stranded cost claim fails to take into account such offsets. For example, Duquesne's Sammis plant could generate $30.9 million in 2010 over and above its direct operating costs assuming Duquesne's "high" market line case. *Id.* Nevertheless, Duquesne presumes the plant will be shutdown in 2010. If the plant were to continue to operate, its operating margin offsets additional amounts of stranded costs. *Id.* at 68:16-21. Similarly, Duquesne's presumptions include shutting down the Eastlake plant the year after that plant contributes more than $15 million in mitigation.[13]

HSS/ARI suggest that the proper indication of whether a power plant should be retired should be based on the unit's going forward costs. *Id.* at 69:11-17. If the unit can recover its variable and fixed costs, including fuel O&M expenses, administrative and general costs, capital additions and taxes from the market value of its power, the plant should continue to operate. Otherwise, it should not. Based on this analysis, Duquesne is prematurely retiring numerous units. As a consequence, its stranded cost claim is overstated and must be adjusted to reflect the offset associated with continued operation of its generating facilities.

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[13]Another benefit from Duquesne's continued operation of the plants would be a deferral of the date when Duquesne must pay decommissioning costs -- thereby reducing the net present value of that obligation. *See* HSS/ARI Statement No. 1 at 71:5-11.

(b) Plant Shutdowns

Several of Duquesne's facilities, *i.e.*, the Elrama, Brunot Island and Perry Units, should be retired immediately. By comparing the data derived from Exhibits RBW-12 ("To Go Cost of Generation") and Exhibit MMS-5, Dr. Weisenmiller determined that the costs of operating these plants exceed the going forward costs. HSS/ARI Statement No. 1 at 70 :13-71:3. Stated otherwise, based on the going forward costs less fuel related expenses (including emissions), variable and fixed O&M, capital additions, and an overhead allocation, Duquesne's assessments of the value of power between 1999 and 2005, it is not economically favorable to continue to operate these named facilities. *Id.* Accordingly, those units should be retired immediately. The effect of those retirements would be a further reduction to Duquesne's stranded cost claim.

(e) Projected Capital Additions and O&M Expense

In considering Duquesne's stranded cost claim, it must be remembered that there are two sides to the equation, *i.e.*, Duquesne's projected revenues have to be measured against Duquesne's projected costs. Thus, an overstatement of stranded costs can as readily occur from an overstatement of cost projections as from an understatement of projected revenues. Clayton, Tr. 266:7-14. As a result, as previously indicated, Dr. Weisenmiller examined Duquesne's costs, as well as its price, projections. In doing so, he identified two significant instances in which Duquesne overstated its projected costs, thus unreasonably inflating its stranded cost claim.

The first of those two instances concerns Duquesne's projections of generation-related capital additions. As Dr. Weisenmiller pointed out, Duquesne forecast those capital additions for some of its generation plants as far out as 2026, or nearly 30 years into the future. HSS/ARI Statement No. 1 57:21-22. Moreover, Duquesne's rate proposal implicitly relies upon the capital additions through

2005. *Id.* at 57:22-58:1. In addition, to calculate its stranded cost claim, Duquesne accounted for generation-related projected capital additions by determining what they would be as of December 31, 2005 on a net present value basis. Thus, Duquesne's claim that it might have stranded costs as of that date expressly is based upon Duquesne's inclusion of the projected costs of those generation-related capital additions. *Id.* at 58:4-6. Duquesne estimated that it would construct capital additions at a cost of $352 million from 1997 to 2005. Exh. DJC-3, at 25. Nonetheless, Duquesne's evidence does not demonstrate any reason why those cost projections should be deemed to be reasonable. On the other hand, the evidence clearly establishes that Duquesne's projections are excessive.

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**REDACTED**

Duquesne's projected O&M expenses also should be reduced. That reduction is warranted for several reasons.

Dr. Weisenmiller compared Duquesne's historic production costs to those of other utilities

in ECAR as well as in Pennsylvania using data from bench marking studies performed by Standard & Poor's Rating Information Services (Exh. RBW-23) and Barakat and Chamberlin, Incorporated (Exh RBW-24). He also reviewed similar bench marking studies commissioned by Duquesne (Exh RBW-25), and statements by Duquesne in recent annual reports. Those sources of data showed that Duquesne's production and operation costs fall short of industry standards in numerous categories. *See* HSS/ARI Statement No. 1 at 62:10 to 64:22; Exhs. RBW-23, 24 and 25. For example, Duquesne's total energy costs were 15% higher than the ECAR average for 1995. Exh. RBW-23 at 6 (Chart). Its fixed production costs were 40% higher than the ECAR average. *Id.* Total production costs exceeded the ECAR average by 20% for 1995. *Id.* Moreover, in a ranking of relative efficiencies of utilities, Duquesne ranked in the bottom third nationwide, lower than any other ECAR and Pennsylvania utilities in the study. HSS/ARI Statement No. 1 at p 63:4-10. Additionally, in a study performed by independent consultants on Duquesne's behalf, the study suggested that Duquesne reduce plant operations personnel by 45%. Exh RBW-4.

Despite lip service from Duquesne with respect to its efforts to become competitive, *see* HSS/ARI Statement No. 1 at 63:15 to 64:15, Duquesne's production costs remain among the highest of the utilities in ECAR. Exh. RBW-23 at 6 (Chart). There are no grounds that support ratepayers' continued subsidization of Duquesne's inefficiencies. Accordingly, the Commission should reduce Duquesne's O&M expenses by 15% as recommended by Dr. Weisenmiller. HSS/ARI Statement No. 1 at 64:28.

(h) Conclusion

For the reasons set forth in Section 3(b), HSS/ARI submits that, even without taking Duquesne's inflated cost projections into account, it is clear that Duquesne does not have any stranded costs. Nonetheless, if the Commission should determine as preliminary matter that there is any basis for Duquesne's claim, the Commission should reduce that claim to account for the overstatement of stranded costs that results from: (1) inappropriate calculations that assume unnecessary early retirements, (2) inappropriate calculations that assume unnecessary continued operation of uneconomic plants and (3) inappropriate calculations that incorporate Duquesne's inflated projections of generation-related capital additions and O&M expenses.

5. Conclusion

As is set forth above, Duquesne's stranded cost claim based upon Schnitzer's computer-generated price projections simply is not credible. Similarly, OCA's and DII's revisions to that claim based upon their own computer-generated price projections are no more meritorious. Rather, the best evidence of the value of Duquesne's generation-related assets is reflected in Duquesne's internal assessment and the independent assessments of its consultant and financial advisor, as corroborated by real market evidence in the form of Duquesne's own sale of its interest in the Ft. Martin plant and other asset sales that have taken place around the country, all of which have taken place at multiples of net book value. In view of that evidence, Duquesne's stranded cost claim should be rejected in its entirety.

C. **Merger Savings**

While HSS/ARI take no position with respect to the proposed merger of Duquesne and APS, Duquesne witnesses testify that the proposed merger will result in approximately $550 million in

mitigation available from cost savings associated with the proposed merger. If indeed the merger proceeds, the Commission should recognize those cost savings and use the full $550 million to offset any allowed stranded costs. These merger savings should be allocated, as appropriate, to offset Duquesne's and West Penn's stranded cost recoveries.

**D. Decommissioning**

1. Nuclear Decommissioning

In his direct testimony, Duquesne witness LaGuardia stated that his estimate of the decommissioning cost for the two nuclear units at Beaver Valley is approximately $727.7 million (1997$). Duquesne Statement No. 13 at 4:4-5. He stated that his estimate of the decommissioning cost of the Perry nuclear unit is $650 million (1997$). *Id.* at 5-6. As part of its stranded cost claim, Duquesne claims $57.4 million in nuclear decommissioning costs on a net present value basis. Exh. DJC-20. pp. 2 and 18 of 49.

In his surrebuttal testimony, Dr. Weisenmiller made clear that he was not attempting to deny Duquesne recovery of amounts needed to make sure that decommissioning of Duquesne's nuclear plants is done appropriately. HSS/ARI Statement No. 15 at 57:10-12. HSS/ARI support that position. Nonetheless, it cannot be overlooked that this is a stranded cost proceeding in which the issue is: has Duquesne demonstrated that it will have generation-related costs that it cannot recover in a competitive market. As a result, because Duquesne has not demonstrated that it has stranded costs, there is no need for the Commission to issue any order at this time concerning funding for nuclear decommissioning. However, again, if the Commission is inclined as a preliminary matter to determine that Duquesne might have some level of stranded costs, it is important to discuss the evidence that demonstrates that Duquesne has failed to establish, in particular, a known and

measurable quantification of stranded costs related to nuclear decommissioning.

In his testimony, LaGuardia describes three alternative methodologies for decommissioning nuclear utilities under the rules of the Nuclear Regulatory Commission ("NRC"). Duquesne Statement No. 13 at 34:14-35:16. While LaGuardia makes a recommendation that he characterized as an "integrated scenario" (*id.* at 36:13-14), it is clear that he does not have much faith in that recommendation because he states that:

> [t]he actual method or combination of methods selected to decommission the generating units should be based on a detailed economic, engineering and environmental evaluation of the alternatives considering the sites and surroundings *at the time of decommissioning and reflecting the latest experience in the decommissioning of similar nuclear facilities.*

*Id.* at 36:6-10 (emphasis added). LaGuardia's foregoing testimony is important in three different respects.

First, LaGuardia acknowledged that the costs of the three different methodologies for nuclear decommissioning are not the same. LaGuardia, Tr. 661:8-17. Thus, given that he is recommending that no decision be reached with respect to the specific decommissioning methodology to use until the time of decommissioning, there is no way to accept a decommissioning estimate today under a known and measurable standard.

A second problem is that LaGuardia recommended with respect to Beaver Valley that decommissioning activities be coordinated to the maximum extent possible. Duquesne Statement No. 13 at 13:17-18. Thus, LaGuardia apparently is recommending that actual decommissioning of Beaver Valley 1 should not occur until the decommissioning of Beaver Valley 2. That would be consistent with LaGuardia's recommendation concerning the decommissioning of fossil plants with

multiple units. *Id.* at 13:8-9. The problem is that Beaver Valley 1 is scheduled to be shut down in 2015, but Beaver Valley 2 is scheduled to remain in operation through 2026. DJC-20, pp. 12-15 of 49. Thus, if Duquesne does not decommission Beaver Valley 1 until 2026, the net present value calculation of the decommissioning costs likely will be substantially less than that set forth in the present value calculation relied upon by Duquesne. LaGuardia, Tr. 659:9-23.

The third problem (viewed from Duquesne's perspective) that arises from LaGuardia's statement quoted above is that it essentially corroborates Dr. Weisenmiller's testimony on the issue. Dr. Weisenmiller pointed out,

> [t]o date, there have only been four completed nuclear power plants that have been decommissioned in the United States. Of these, only one was even remotely similar in size and power output to Beaver Valley 1 and 2 or Perry, (*e.g.*, Shoreham, near Wading River, NY at 2436 MW). Thus, there is almost no established track record associated with decommissioning large-scale utility nuclear power plants.

HSS/ARI Statement No. 1 at 74:16-20. As a result, based upon the absence of prior experience in developing an estimate of decommissioning costs, Dr. Weisenmiller concluded that

> it is likely that cost proposals from contractors and estimators err on the side of excessive estimation of costs. On the other hand, a number of nuclear plants are nearing retirement. As a result, the costs of decommissioning may be lower than expected by Duquesne because any new costs will be shared among a number of plant operators.

*Id.* at 74:22-75:4. In view of Mr. LaGuardia's statement that an actual decommissioning methodology should not be developed until "*the time of decommissioning and reflecting the latest experience in the decommissioning of similar nuclear facilities,*" it appears that he endorses Dr. Weisenmiller's concerns.

Based upon the foregoing, HSS/ARI submit that Duquesne has not demonstrated the known and measurable costs of nuclear decommissioning, let alone demonstrated the amount of any such costs that Duquesne will be unable to recover through its sales of generation in a competitive market. Thus, HSS/ARI submit that the Commission should not reach a determination today concerning nuclear decommissioning costs that are not known and measurable and which Duquesne has not shown are stranded. Accordingly, Duquesne's request for $57.4 million in alleged nuclear decommissioning costs should be rejected.

As an alternative, if the Commission believes it must address the issue of nuclear decommissioning costs at this time, HSS/ARI support Dr. Weisenmiller's proposal that the Commission retain an independent expert in the field to perform an audit as described in Dr. Weisenmiller's testimony. HSS/ARI Statement No. 1 at 72:19-74:2. Further, given the magnitude of these costs, Duquesne must bear some cost responsibility for a forecast error if a decommissioning amount is specified in this proceeding either as a result of an independent audit, adoption of LaGuardia's testimony or any other procedure. Specifically, HSS/ARI recommend adoption of the risk-sharing mechanism under which ratepayers are responsible for 75% of any over-or under-collection of decommissioning costs as described by Dr. Weisenmiller. *Id.* at 77:1-4. Accordingly, utility shareholders would be responsible for 25% of any forecasting error associated with the decommissioning cost estimate that the Commission may ultimately adopt. *Id.*

As part of that proposal, HSS/ARI also recommend that the Commission establish a balancing account to recover actual decommissioning costs. *Id.* at 76:15-16. In this proposed account, any increases or decreases in decommissioning costs that arise from comparison of actual expenditures to the Commission-approved estimated decommissioning costs would be shared by

ratepayers and shareholders. *Id.* at 76:16-19. Moreover, the Commission could require Duquesne to account for items such as land values that Duquesne and LaGuardia heretofore have failed to consider in assessing plant values. *See* LaGuardia, Tr. 664:19 - 666:7. Absent such a balancing account, Duquesne could fail to correctly identify potential offsetting items, which Duquesne admits are difficult to predict with certainty. LaGuardia, Tr. 665:11-22. Further, in such balancing account, ratepayers should be credited with the amount obtained by Duquesne in its 1994 settlement with General Electric concerning the Perry 1 GE Mark III reactor. *See* HSS/ARI Statement No. 1 at 75:14-76:6.

2. Fossil Decommissioning

As the Commission held in *PECO*, future or prospective fossil plant decommissioning expenses are not traditionally recognized in rates in Pennsylvania, nor do they satisfy the known and measurable test for recovery as stranded costs. *PECO* at 91-92 (citing *Penn Sheraton Hotel Co. v. Pennsylvania Public Utility Comm'n*, 198 Pa. Super. Ct. 618, 184 A.2d 324 (Pa. Super. Ct. 1962)). Accordingly, Duquesne is not entitled to recover fossil decommissioning costs.

Moreover, a recent Commission Staff audit casts significant doubt as to the accuracy of Duquesne's claimed fossil decommissioning costs in any event. *See* Exh. RBW-26. In that audit, Commission Staff sampled Duquesne's property records and found that plant balances were overstated by over $2 million, in part due to unrecorded retirements or items not devoted to utility service. *Id.* Obviously those costs should not be collected from ratepayers. Moreover, the Commission Staff's audit was by no means comprehensive. Staff sampled only 95 of 350 work orders. Of those 95, Staff inquired about 35 and received either incomplete or unsatisfactory answers with respect to twenty-five -- more than 25% of those work orders sampled. Exh. RBW-26

at 4-5. Thus, the audit results provide a ground, independent of the PECO Order, demonstrating that Duquesne's claimed fossil decommissioning expenses in particular, do not satisfy the known and measurable standard.

## E. Regulatory Assets and Liabilities

### 1. Introduction

Duquesne has asserted claims for recovery of numerous costs under the rubric of regulatory assets. A utility may seek to recover regulatory assets and other deferred charges typically recoverable under current regulations as stranded costs. 66 Pa. C.S. § 2803. As *PECO* makes clear, Section 2808(c)(1) (the CTC mechanism) permits recovery of regulatory assets "that are not presently included in rates but which the utility is *already* entitled to recover through future rate adjustments." *PECO* at 66 (emphasis added). In the instant restructuring proceeding, Duquesne has sought to recover numerous items as regulatory assets without any such pre-existing entitlement. Accordingly, the Commission should deny Duquesne's attempt to recover as regulatory assets amounts that do not qualify as such.

### 2. Disputes Regarding Specific Claims

#### (a) SFAS 109 Deferred Taxes

In its application, Duquesne sought to recover as a regulatory asset a regulatory tax receivable of $304.94 million. Duquesne Statement No. 4 at 8; Exh. DJC-4 at 1; *see also* Exh. RBW-33. In its rebuttal testimony, Duquesne reduced that claim to $179 million on a net present value basis. HSS/ARI opposes Duquesne's recovery of that amount for two fundamental reasons.

First, and as previously discussed, Duquesne has not had a rate case in over 10 years as a result of its own decision not to subject its costs to regulatory scrutiny. Thus, there is no finding that

Duquesne's capital expenditures during that 10 year period were just and reasonable. Now Duquesne wishes to claim as a regulatory asset a regulatory tax receivable of $179 million on a net present value basis that partly depends on Duquesne's capital expenditures that never have been reviewed. Thus, Duquesne is attempting to bootstrap a deferred tax claim that is predicated on capital additions that Duquesne is *not already* entitled to recover. HSS/ARI Statement No. 1 at 107:1-6. Accordingly, Duquesne's request conflicts with the Commission's ruling in *PECO* that stranded costs recoverable under "Section 2808(c)(1) includes regulatory assets and other deferred charges that are not presently included in rates but which the utility is *already entitled* to recover through future rate adjustments." PECO Order at 66 (emphasis added).

Second, Duquesne's argument in support of its claim is that:

> [T]his regulatory asset was booked in recognition of the fact that the tax benefits will "turn around" in the future, leading to a higher tax expense which must be paid by the Company. At that time, however, the plant which gave rise to the accelerated depreciation will no longer be in jurisdictional rates. Ratepayers, therefore, would have gotten the benefit of lower rates in the past due to the tax advantages of the accelerated depreciation, but also would be able to avoid the higher tax bill in the future when the assets which gave rise to be (sic) depreciation become deregulated.

Duquesne Statement No. 4 at 8:19-9:1.

However, Duquesne's justification is inconsistent with fact. Because Duquesne did not file a rate case for over 10 years, the tax advantages that Duquesne claims were not flowed through to ratepayers in the form of reduced rates. Rather, as shown *supra* at 15, Duquesne has flowed through any such tax advantages exclusively to its shareholders. Accordingly, the Commission should not authorize Duquesne's recovery of the claimed $179 million as a regulatory asset.

(b) Unamortized Debt Costs

Duquesne seeks to recover unamortized debt costs as a stranded regulatory asset. The unamortized premium represents the excess of the reacquisition price over the net carrying amount of certain debt costs. Duquesne Statement No. 4 at 9:9-11. However, Duquesne has failed to demonstrate any nexus between the claimed stranded costs and the electric utility restructuring occasioned by the Customer Choice Act. Duquesne Witness O'Brien states only that "[d]ue to restructuring . . ., the Company will not be able to recover fully the unamortized (sic) remainder of the expense." *Id.* at 10. He does not contend, however, that *none* of the balance will be recoverable though Duquesne has claimed the entire amount as a regulatory asset.

Duquesne currently amortizes the cost of reacquired debt over the life of the debt. *See* Exh. RBW-47. In this proceeding, Duquesne proposes to recover the entire reacquisition premium during the transition period. Duquesne Statement No. 4 at 9:19 to 10:15. This proposal is not reasonable. Because the regulatory asset portion of these costs was incurred to finance the construction and/or purchase of generating assets, the reacquisition premium and issuance cost should be amortized consistent with Commission policy, *i.e.*, over the remaining life of the debt. Duquesne's generating assets will not disappear in their entirety at the end of the transition period. Operating units (and Duquesne's shareholders) will continue to benefit from the lower debt costs obtained by refinancing in future years. Thus, it would be inequitable to allow Duquesne to realize a benefit while at the same time it recovered a CTC associated with its unamortized debt costs.

One of the central tenets of regulatory policy is to match the cost of a benefit with the benefit itself. Duquesne's proposal ignores that principle by making ratepayers responsible for all of the post-2001 cost of this item while conferring the post-2001 benefit on Duquesne's shareholders.

HSS/ARI Statement No. 1 at 109:8-17. As Dr. Weisenmiller has testified, if Duquesne divests its assets, presuming the transaction is a taxable event to Duquesne, any remaining portion of this regulatory asset must be paid down. *Id.* at 109:21-22. Moreover, if Duquesne's generating assets retire prior to full recovery, the remaining balance of the regulatory asset must be recovered at that time through a one-time charge. *Id.* at 110:3-4. Duquesne's rebuttal testimony did not challenge any of these propositions. Therefore, Duquesne's request to recover unamortized debt costs and unamortized premium on reacquired debt as regulatory assets should be denied.

(d) Deferred Rate Synchronization Costs

Duquesne's claim for $41.5 million in deferred Rate Synchronization Costs also should be rejected. Duquesne cannot demonstrate that such costs have been approved by the Commission nor can Duquesne claim that it *already* is entitled to the recovery of those costs. *See* PECO at 66.

Duquesne petitioned the Commission to defer initial operating and other costs of the Beaver Valley Unit and Perry Unit 1 from November 1987. Duquesne Statement No. 4 at 10:16-22. Duquesne Witness O'Brien cites the November 1987 Order in Docket No. R-870222 for the claim that Duquesne was allowed to "seek recovery over time" of these costs. *Id.* However, that claim simply is not accurate. The November 1987 Order expressly declined to approve the recovery of these costs, declined to pass on the costs' prudence or whether the units at issue were used and useful, declined to adjudicate the justness and reasonableness of the expenditures and specified that "this Order is not to be construed as a determination by the Commission . . . that Duquesne . . . may recover any of the deferred costs . . . ." Exh. RBW-36. Thus, the November 1987 Order does not support Duquesne's claim to be entitled to recover these costs.

Moreover, the Commission never has authorized Duquesne to recover these costs. HSS/ARI

Statement No. 1 at 95:12-15 and Exh. RBW-37. In fact, in the Ft. Martin proceedings, as a result of OCA objections to a Duquesne proposal, Duquesne amended its proposal specifically to recognize that the OCA had not agreed to the recovery of these costs in Duquesne's next base rate proceeding. Exh. RBW-38.

Thus, the Commission has twice declined to permit Duquesne to recover these costs. HSS/ARI Statement 1-SR at 18:14-18. Accordingly, Duquesne is not entitled to recover its deferred Rate Synchronization Costs as a regulatory asset in this proceeding.

(f) Deferred Coal Costs

Duquesne seeks to recover $13.5 million in deferred coal costs. Duquesne Statement No. 2R at 27:17-18. This is not supported by Commission authority and must be denied. As the Commission held with respect to deferred fuel costs in *PECO*, "undetermined future [fuel] expenses cannot qualify as recoverable stranded costs under the [Customer Choice] Act." *PECO* at 71. Duquesne's justification for recovery of deferred coal costs are based on the projection that "fuel costs are expected to decline in the year 2000 . . . ." Duquesne Statement No. 2-R at 28:1-2. However, Duquesne's opportunity to recover deferred coal costs is predicated on the realization of certain contingencies. HSS/ARI Statement No. 1 at 96:15 to 97:15. In fact, Duquesne testifies as to the speculative nature of projections of future energy costs. *See* Duquesne Statement No. 3 at 8-9. Accordingly, Duquesne cannot determine its future deferred coal costs on a net known and measurable basis. Duquesne's attempt to recover such costs therefore must be rejected.

Apart from this restructuring proceeding, Duquesne has recognized that its opportunity to recover the deferred costs is permissible only if "the delivered costs of coal fall below such PUC-determined prevailing market prices." Exh. RBW-39. Accordingly, Duquesne had no assurance that

its aggregate coal costs would be sufficiently low as to permit collection of the deferred amounts apart from this restructuring proceeding. Consequently, recovery of deferred coal costs was highly contingent long before this restructuring proceeding. Accordingly, Duquesne cannot now claim that these costs are "determinable." Therefore, Duquesne is not entitled to recovery of deferred coal costs as a regulatory asset.

(g) Deferred Caretaker Costs

Duquesne attempts to recover approximately $6.77 million in costs associated with the "care and feeding" of the Phillips and Brunot Island facilities as well as the underlying capital investments -- which it claims to be $106.8 million. *See* Duquesne Statement No. 4 at 15:12-14. The Phillips and Brunot Island Units are not, however, entitled to be recovered as stranded regulatory assets.

As was previously discussed, these facilities were shutdown and taken out of service ten years prior to this restructuring proceeding. Had these units been retired in 1986, ratepayers would not have to be burdened with caretaker costs incurred to preserve Duquesne's business options. HSS/ARI Statement No. 1-S at 22:1-12. Thus, ratepayers should not have to bear the burden of Duquesne's poor management decisions. *Id.* These facilities have been excluded from Duquesne's rate base since 1986. Accordingly, these caretaker costs are not related to the industry restructuring. Therefore, these costs should be removed from Duquesne's stranded cost claim.

(j) FAS No. 106 Deferred Costs

Duquesne claims that it is entitled to recover $22.43 million in FAS No. 106 costs as a stranded regulatory asset. Duquesne Statement No. 4 at 7:27. The FAS No. 106 costs, which Duquesne began accruing in 1993 (*id.* at 13:23 to 14:1), relate to certain health care benefits and life insurance for some of the Company's retired employees. *Id.* at 13:20-21. Duquesne's requested

recovery of these costs must be rejected for several reasons. First, in its direct case Duquesne offered no support for Commission approval of the costs. Duquesne Statement No. 4 at 7:27. Moreover, Duquesne essentially concedes that FAS No. 106 costs are not a regulatory asset. Duquesne Statement 2-R at 31:8-12. Nonetheless, Duquesne asserts that it is justified in recovering FAS No. 106 costs because these costs are a "GAAP" liability which currently exists. Duquesne Statement 2-R at 31:8-12. However, under that standard, any liability would qualify for recovery. HSS/ARI Statement No. 15 at 27:8-10. Accordingly, Duquesne should be proscribed from recovering its FAS No. 106 costs as a regulatory asset.

(k) Warwick Mine Costs

Duquesne seeks to recover over $15 million in claimed stranded costs associated with the Warwick Mine. *See* Duquesne Statement No. 4 at 7:29. The claimed $15 million represents the net book value of Duquesne's investment in the mine. In 1996, the operator of Warwick Mine informed Duquesne that it was ceasing to operate the mine. Exh. RBW-39. Duquesne therefore is seeking direct recovery of its capital investment in the mine from its ratepayers. *Id.* at 98:19-20. This attempt is wholly unjustified.

On February 21, 1981, the Commission required Duquesne to remove Warwick Mine from the Company's rate base. Exh. RBW-40. In the event that the Warwick Mine were efficient enough to produce coal at a cost below the average price of comparable coal, Duquesne would have been permitted to earn a reasonable return on its investment. *Id.* In addition, after 1981, Duquesne was permitted to recover its investment in Warwick Mine through the cost of coal subject to the coal cost

cap in the ECR.[14] Nonetheless, Duquesne acknowledged in 1995 that the Warwick Mine had been excluded from the rate base since 1981. Exh. RBW-41.

For the same reason applicable to deferred coal costs, Warwick Mine capital investment does not qualify as a regulatory asset -- recovery of costs was not assured, but could occur only when costs fell within the ECR charge. As *PECO* holds, only determinable costs already approved by the Commission are to be afforded regulatory asset status. Duquesne's attempt to justify inclusion of Warwick Mine in its stranded cost claim thus must fail because these costs are not determinable nor justified by Commission approval. Because there has been no production from the mine well before this restructuring proceeding, Duquesne is not entitled to collect any cost of, much less its capital investment associated with, the mine under the coal cost cap.

(m) Compensated Absences

Duquesne seeks to include approximately $8 million in costs associated with compensated absences as regulatory assets. However, Duquesne has not adequately justified these costs. Duquesne has eliminated hundreds of employees over the last decade and likely could eliminate a significant number more in the future as a result of competition, the proposed merger with APS or both. *See* HSS/ARI Statement No. 1 at 113:6-21. Given that no scenario suggests that Duquesne's employee headcount will remain constant much less increase, at a minimum, Duquesne has failed to demonstrate that its compensated absence accruals will *not* result in a windfall as the company reduces its headcount. Moreover, Duquesne has not provided any evidence to support the actual proportion of these costs that is directly related to generation; nor has Duquesne even rebutted

[14]This also applied to deferred coal costs. HSS/ARI Statement No. 1-S at 21:14-15. *See* Section IV. E. 2(f), above.

criticisms of its claim for regulatory asset status of compensated absences. HSS/ARI Statement 1-S at 17:25 to 18:2. Therefore, the Company has failed to make any showing that it is entitled to include $8 million in compensated absences in its stranded cost claim.

(k) Injuries/Damages

Duquesne seeks to recover over $9 million in costs associated with Injuries and Damages as generation-related regulatory assets. Duquesne Statement No. 4 at 7:20. Duquesne Witness O'Brien claims that "[t]hese costs relate to the Company's workers (sic) compensation liability." *See* Duquesne Statement No. 4 at 11:10-21. Duquesne claims that this regulatory asset results from a difference in timing between when the liability is booked and when amounts are actually recovered through its rates. *Id.* However, Duquesne has not established the justness and reasonableness of these claimed amounts since its last rate case in 1987 (Docket No. R-870651). *Id.* at 11:14-15. Moreover, Duquesne Witness O'Brien apparently concedes that only generation-related amounts are recoverable. *See id.* at 11. Duquesne has not demonstrated that any of the expenses claimed are generation-related. Accordingly, it is not entitled to recover such expenses in its CTC.

3. Conclusion

As set forth in detail above, Duquesne has failed to adequately establish that numerous items are entitled to regulatory asset status. Accordingly, Duquesne should not be permitted to include such costs in its stranded cost claim.

## F. Recovery Of Stranded Costs

1. Introduction

As set forth in Section IV.B above, the evidence demonstrates that Duquesne has failed to show that it has any stranded costs. The evidence further establishes that even if Duquesne had any

stranded costs, its recovery of those costs should be denied based upon Duquesne's failure to fully mitigate, consistent with its obligations under the Act.

2. Proposals To Adjust The Level Of Stranded Cost Recovery

(a) Mitigation

Section 2808(C)(4) provides in pertinent part that

> [i]n determining the level of stranded costs that an electric utility may recover through the competitive transition charge . . . the Commission shall consider the extent to which the electric utility has undertaken efforts to mitigate generation-related stranded costs . . . .

Consistent with that mandate, Mr. Marshall testified that

> we believe our obligation, our obligation is to fully mitigate our costs to the extent that we have assets that we are collecting dollars on. As part of the transition to customer choice we should do everything we can and we do everything we can to get any additional revenues in so we mitigate our stranded costs.

Marshall, Tr. 120:20-121:1.

Mr. Marshall agreed that if generation assets were sold at an amount above net book value, the excess recovery would be credited to ratepayers, thus mitigating stranded costs. Marshall, Tr. 69:14-70:1. Mr. Marshall also acknowledged that he was aware of generation assets being sold "on a wide-spread basis." Marshall, Tr. 68:13. He further admitted that "the ones that I am aware of have been done above book value . . . ." Marshall, Tr. 68:19-20.

Thus, it is obvious that if Duquesne intended to carry forth with its "obligation" to fully mitigate, it would have placed its generation assets up for sale while there is a robust market that is paying in excess of net book value for existing generation plants. In fact, Merrill Lynch expressly advised Duquesne in 1995 that it believed there would have been a strong reception for Duquesne's

assets at the time. Exh. RBW-56. Instead, Duquesne has one proposal before the Commission under which it would offer its assets for sale in 2003. Duquesne Statement No. 2R at 3:176-17 And, it has another proposal before the Commission under which it would offer its facilities for sale immediately, but only if its proposed merger with APS is rejected. Duquesne Statement No. 1 - Rejoinder at 1:17-19: Marshall, Tr. 178:25-179:5. Thus, Duquesne's proposal to sell its generation assets now is a proposal that Duquesne intends to withdraw if its preferred goal, its proposed merger, is approved. And, its proposal to sell assets in 2003 in no way can be deemed adequate mitigation. After all, there is no assurance that the seller's market that exists today for generation assets still will exist in 2003. Of course, that is not of particular concern to Duquesne because under its proposal, it will be collecting CTCs during the four-year period that would proceed its proposed asset sale, notwithstanding the mitigation that could occur if the sale were to take place today. As a consequence, it cannot be determined that Duquesne has taken any step to carry forth with its obligation to mitigate stranded costs in view of its refusal to place the assets up for sale today to capture the premiums that currently are being paid in the market for existing generation facilities. Thus, Duquesne's failure to mitigate properly should be taken into consideration in the Commission's evaluation of Duquesne's right to recover any stranded costs it arguably might have.

3. Methods of Stranded Cost Recovery

(a) Accelerated Amortization Under Section 2804(4)(v) (Duquesne's ROE Spillover Proposal)

As previously discussed, Duquesne claims an entitlement to the rate floor protection of Section 2804(4)(v) of the Act based upon its proposal to accelerate depreciation and amortization of its generation assets by $1.7 billion through 2005 ostensibly for the purpose of mitigating stranded

costs. However, as HSS/ARI has demonstrated above, Duquesne has no stranded costs to mitigate. As a consequence, Duquesne has no right to accelerate amortization and depreciation, and as will be discussed in Section F3(b), below, by doing so, it only would provide an artificial and improper basis to prop up its cost of service to support exorbitant rates that are not just and reasonable. Accordingly, the Commission should reject Duquesne's request to accelerate amortization and depreciation because the statutory basis for authorizing such acceleration is absent in this case.

However, if the Commission does allow Duquesne to accelerate amortization and depreciation by any amount, the Commission should reject Duquesne's proposed "ROE spillover mechanism." Alternatively, the mechanism should be modified to prohibit Duquesne from using the mechanism to supplement earnings.

As Dr. Weisenmiller explained in his testimony, the ROE spillover mechanism is a sham. HSS/ARI Statement No. 1 at 137:19. Under the proposal, as Duquesne modified it in its rebuttal testimony, if Duquesne achieves earnings in excess of 11.5%, it will set up a deferred revenue account and will record the excess earnings to the account. Duquesne Statement No. 2 at 42:15-17; Clayton, Tr. 243:13-19. However, once the deferred revenue account is established, if Duquesne's earnings fall below 11.5%, Duquesne will debit the account to boost its earnings back up to 11.5%. Clayton, Tr. 244:1-16. The mechanism is subject to substantial abuse.

For instance, Duquesne did not make any representation that it would not use write-downs to offset earnings. If it did record such write-downs, it artificially could depress its net earnings, but then boost them back up by taking funds out of the deferred revenue account to get Duquesne its guaranteed 11.5% ROE. HSS/ARI Statement No. 1 at 138:6-8. Thus, as Dr. Weisenmiller pointed out, the ROE spillover not only does not protect ratepayers, Duquesne actually could use the ROE

spillover to exacerbate ratepayers' liabilities to fund Duquesne's non-existent stranded costs. *Id.* at 138:8-10. As a result, the Commission should reject Duquesne's proposed ROE spillover mechanism or modify it to prohibit Duquesne from using the mechanism to supplement earnings. HSS/ARI Statement No. 1S at 11:19-21.

(b) Immediate Rate Reductions

Based on the evidence in this case, the Commission should order an immediate reduction of Duquesne's rates. The basis for that reduction is that Duquesne's current rates (which it proposes to maintain) are not cost-justified and therefore are not just and reasonable.

Again, the starting point for this analysis logically must start with another consideration of the historic costs that Duquesne would include in determining its rates but which never have been shown to be just and reasonable. As has been discussed previously, Duquesne has chosen not to file a rate case since 1986, and Duquesne presented no evidence in this case to establish that its expenditures over that ten year period were just and reasonable. As a result, the Commission should order a 50% disallowance of the approximately $382 million in generation-related capital expenditures Duquesne has made since 1986.

There also is an independent problem that arises directly from Duquesne's rate proposal. As can be seen in Duquesne's cost of service study, Duquesne would adjust its generation-related 1996 test year results to reduce Total Power Production Expenses by approximately $21 million. Exh. MKO-1B, p. 2. Duquesne explains by reference to footnote 12 on the preceding page that the $21 million cost reduction largely relates to Duquesne's sale of its interest in Ft. Martin. However, as can be seen on page 3 of the same exhibit (Exh. MKO-1B, p.3, line 403), Duquesne is proposing to increase its depreciation expense by $25 million, again because of the Ft. Martin sale (O'Brien, Tr.

615:13-616:10), thus more than offsetting the entire cost reduction and alleged benefit that Duquesne claims its ratepayers received from the sale. However, to add insult to injury, as can be seen on the same page at line 405, Duquesne's proposal to amortize transition costs would increase its 1996 test year cost of service in the amount of $84 million. O'Brien, Tr. 616:11-617:5. As can be seen on the last line on Exhibit MKO-1B, page 3, the net effect of Duquesne's proposal thus is to increase its cost of service by $62 million rather than reducing that cost of service by $22 million as would occur with rejection of Duquesne's proposal to accelerate amortization and depreciation. O'Brien, Tr. 617:17-20. As a result, the Commission should reject Duquesne's request to accelerate amortization and depreciation and require Duquesne to calculate its rates based upon the reduced cost of service that would result from the reduced generation and distribution rate based upon the adjustments discussed herein. Such a reduction is necessary if Duquesne is to be precluded from earning the inflated returns on equity that it has forecast it will earn. *See supra* at 14; *see also* HSS/ARI Statement No. 1 at 78.

(d) Other Proposals (Duquesne's Proposal to Defer Valuation Until 2003)

One of Duquesne's primary proposals is its request to defer the date when there would be a valuation of Duquesne's generation assets until 2003. HSS/ARI oppose that request. The Act provides a statutory scheme that contemplates that Duquesne must prove in this case whether or not it has stranded costs. Had Duquesne proven its case, it would have been entitled to recover stranded costs through a CTC. However, Duquesne seeks to avoid making the required showing, but nonetheless collect a CTC and then in 2003, revisit the issue. That is not the regulatory scheme the legislature enacted for determination of a utility's stranded cost claim. As such, there is no basis to adopt it, and it should be rejected.

### G. Conclusion

For the reasons set forth above, HSS/ARI request that the Commission find that Duquesne failed to establish that it will have any stranded costs.

## V. THE COMPETITIVE TRANSITION CHARGE

### A.1. Conceptual Disputes Regarding Calculation Of CTC/CGC

HSS/ARI submit that there are no grounds for Duquesne to recover a CTC because Duquesne has no stranded costs and thus has no entitlement to charge a CTC. Nonetheless, if the Commission grants any portion of Duquesne's stranded cost claim, HSS/ARI submit that Duquesne's proposal for calculating CGCs and CTCs should be rejected.

Duquesne proposes to calculate CGCs and CTCs based upon an annual solicitation for block power sales. Duquesne Statement No. 5 at 29:1-2. As described by Duquesne's witness Lahtinen, Duquesne would design the CGC based upon the results of the annual solicitation. *Id.* at 56:22-57:1. In simple terms, Duquesne would make certain adjustments to the results of the annual solicitation ostensibly to try to take the solicitation results from a wholesale to a retail level. Lahtinen, Tr. 728:13- 729:5; *see also* Duquesne Statement No. 5 - Rejoinder at 2:16. The CGC, along with unbundled charges for transmission, distribution and ancillary services, would be subtracted from Duquesne's current rates to develop CTCs. Duquesne Statement No. 5 at 29:3-4. To understand the shortcomings in Duquesne's proposal, one merely must consider Duquesne's own testimony concerning the ramifications that would flow from an inappropriate design for CGCs in particular.

With respect to one of those ramifications, Lahtinen testified,

> [i]f the CGC is set below the actual market price, customers will have an artificial incentive to stay with Duquesne. The result could hinder competition and retard the development of a competitive retail

electricity market.

Duquesne Statement No. 5 at 56:9-11. Unfortunately, the setting of an unreasonably low CGC that will hinder competition and retard the development of a competitive retail market are the precise outcomes that will occur if Duquesne's proposal is adopted. That is the only conclusion one can reach in view of the RFP Duquesne conducted last summer.

HSS/ARI will not repeat the numerous flaws in Duquesne's 1997 RFP that demonstrate that the type of solicitation Duquesne intends will understate even a valid wholesale, let alone a retail market price in Duquesne's service territory. HSS/ARI rely upon the discussion at __ through __ *supra* to demonstrate that point. However, HSS/ARI would reiterate one fact, *i.e.*, that Duquesne's version of a CGC would not even provide a bidder "headroom" to recover its overhead or a profit margin. Notwithstanding that fact, or maybe because of it, Lahtinen actually suggested that alternate suppliers will be willing to sell indefinitely at a loss. Lahtinen, Tr. 740:15-743:9; *see also* Duquesne Statement No. 5 at 62:1-6. Thus, acceptance of Duquesne's proposal only would "hinder competition and retard the development of a competitive retail electricity market," a result at odds with the very intent of the Act. As such, Duquesne's proposed methodology for setting CGCs and CTCs should be summarily rejected.

A.2(b) Determination of Class Responsibility for Stranded Costs

A separate problem concerning Duquesne's CGC and CTC rate design results in a overstatement of particular classes' stranded cost responsibility in the event that Duquesne is authorized to recover any such amount. It should be noted that the overstatement of stranded cost responsibility does not require a reallocation of costs, although, in effect, Duquesne is shifting stranded cost responsibility among classes in violation of the Act. 66 Pa. C.S. § 2808(A).

The problem is identified in Mr. Lahtinen's testimony. He stated that in allocating costs to individual rate classes, he was required to reduce the generation component of unbundled rates for certain classes to maintain the rate cap required by the Act. Duquesne Statement No. 5 at 25:3-5. That reduction obviously was required and is appropriate.

However, for certain other rate classes, "where costs are below revenue levels, [Lahtinen] adjusted the generation component to meet, but not exceed, 1996 revenues. *Id.* at 25:5-7. That latter upper adjustment clearly is inappropriate.

In effect, Lahtinen "wrote-up" the rates of these latter classes to recover revenues that are not those classes' responsibility. Similarly, by writing up the latter classes rates, Lahtinen was shifting generation-related revenue responsibility to them for revenues properly chargeable, but not collectible, from other rate classes because of the rate cap provisions of the Act. According to Mr. Lahtinen, the classes whose revenue responsibility was written up would be those whose allocated cost of service is less than the allocated 1996 revenues on page 2 of Exhibit JAL-3, p. 2. Thus, Duquesne's rate proposal should be modified by reducing revenue responsibility for the following classes: RS, GS/GM, GL, SH and Traffic Lights. *See* Exh. JAL-3, p. 2.

## VI. RATE OF RETURN/DISCOUNT RATE

In his direct testimony, Dr. Weisenmiller pointed out that the enactment of the Customer Choice Act dramatically reduced the risk of stranded cost recovery facing Duquesne, *inter alia*, by authorizing a non-bypassable CTC charge. HSS/ARI Statement No. 1 at 84. Based upon that reduced risk, Dr. Weisenmiller recommended that Duquesne's ROE be reduced to reflect Duquesne's lower risk. *Id.* at 84-86.

The Commission now has had the opportunity to rule on the appropriate rate of return issue

in the context of considering PECO's stranded cost claim. In that proceeding, the Commission adopted the same approach advocated by Dr. Weisenmiller, finding that the risk of non-payment of CTCs is minimal, and that recovery of PECO's full principal amount is assured through the reconciliation mechanism of Section 2808(f). PECO, *mimeo* at 108. Thus, the Commission concluded that the level of risk of collecting CTCs does not compare to the risk associated with generation charges collected under regulated rates. *Id.* As a result, the Commission ruled that PECO long-term debt rate of 7.47% should be used to calculate PECO's revenue requirement for the recovery of CTCs. *Id.* Consistent with that ruling, Duquesne should be authorized to use its long-term debt rate for purposes of calculating its CTC-related revenue requirement if it is granted any stranded cost recoveries in this proceeding.

## VII. SPECIAL CUSTOMER CLASSES

### A. Rule 4 Contracts

HSS/ARI support Duquesne's continued ability to offer Rule 4 contracts. HSS/ARI also believe, consistent with Duquesne's proposal, that existing Rule 4 contracts should remain in effect during their term. However, parties with Rule 4 contracts should not be deprived of benefits that result from this proceeding. Accordingly, if the rates ordered as a result of this proceeding are lower than the rates that would apply under a particular Rule 4 contract, the rates ordered herein should be available to the particular Rule 4 customer in lieu of the higher rates set by the Rule 4 contract. That result is required because in the circumstance described, the Rule 4 rates would not be just and reasonable.

## XIII. CONCLUSION

**WHEREFORE**, for the foregoing reasons, HSS/ARI respectfully request that the Commission:

(1) deny Duquesne's stranded cost claim in its entirety;

(2) deny Duquesne's request to accelerate amortization and depreciation of its generation assets;

(3) deny Duquesne's request for authority to charge a CTC;

(4) order an immediate reduction in the unbundled generation component of Duquesne's rates;

(5) order an immediate reduction in the unbundled distribution component of Duquesne's rates;

(6) reject Duquesne's request to defer to a later date a final valuation of its generation assets for the purpose of establishing its stranded costs; and

(7) require that Duquesne offer the rates ordered herein to its Rule 4 customers to the extent the rates ordered herein are lower than the rates in a Rule 4 contract.

Respectfully submitted,

Kenneth L. Wiseman
Mark F. Sundback
Peter J. Thompson
Robert M. Lamkin
Andrews & Kurth L.L.P.
A Registered Limited Liability Partnership
1701 Pennsylvania Avenue, N.W.
Washington, D.C. 20006

ATTORNEYS FOR HOSPITAL SHARED SERVICES AND ADMINISTRATIVE RESOURCES, INC.

Dated: February 10, 1998

**Duquesne**

**SUMMARY OF STRANDED COSTS ($000) NPV $1999**

| | Company Claim | Adjustments | Adjusted Amount | Note/Source |
|---|---|---|---|---|
| Nuclear | 934,400 | -- | -- | John Moot, Skadden, et.al. |
| Fossil | 607,290 | -- | -- | John Moot, Skadden, et.al. |
| Subtotal (generating assets) | 1,541,690 | -2,022,690 | -481,000 | See RBW-57 (CS 1st Boston market line). |
| Regulatory Assets | 357,280 | 265,210 | 92,070 | John Moot, Skadden, et.al. |
| Total | 1,898,970 | 1,814,620 | -388,930 | |
| PUC Jurisdictional Percent | 99.9% | | | John Moot, Skadden, et.al. |

**Duquesne**

**STRANDED COST CALCULATION - NUCLEAR ($000) NPV $1999 ***

| | Company Claim | Adjustments | Adjusted Amount | Note/Source |
|---|---|---|---|---|
| Net Book Value | 788,590 | 0 | 788,590 | |
| Market Value | 7,200 | NA | NA * | Not separately estimated. However market revenues of sale are likely to exceed net book value. |
| PV of Nuclear Decommissioning | 57,400 | 57,400 | NA | Not estimated. Recommend audit to establish costs (RBW p. 72). |
| PV of Costs Indep. of Operation | 95,610 | 95,610 | 0 | John Moot, Skadden, et.al. (Company Claim). |
| Total | 934,400 | 934,400 | 0 | |
| Discount Rate | 7.832% | | | John Moot, Skadden, et.al. (Company Claim). |
| PUC Jurisdictional Percent | 99.9% | | | |

* Stranded costs of nuclear assets were not separately estimated. However, market revenues are likely to exceed net book value, as shown in RBW-57 (CS 1st Boston market line). See Summary of Stranded Costs table.

**Duquesne**

**STRANDED COST CALCULATION - FOSSIL ($000) NPV $1999 ***

| | Company Claim | Adjustments | Adjusted Amount | Note/Source |
|---|---|---|---|---|
| Net Book Value | 448,370 | 297,800 | 150,570 | Brunot Is. and Phillips Removed. Disallowance of 50% of cap adds. |
| Market Value | 20,200 | NA | NA * | Not separately estimated. However market revenues of sale are likely to exceed net book value. |
| PV of Decommissioning | 66,500 | 66,500 | NA | Recommend review of work orders before DQE is permitted to recover decomm. Costs (RBW p. 72). |
| PV of Costs Indep. of Operation | 112,620 | 112,620 | 0 | John Moot, Skadden, et.al. (Company Claim). |
| Total | 607,290 | 476,920 | 0 | |
| Discount Rate | 7.832% | | | |
| PUC Jurisdictional Percent | 99.9% | | | |

* Stranded costs of fossil assets were not separately estimated. However, market revenues are likely to exceed net book value, as shown in RBW-57 (CS 1st Boston market line). See Summary of Stranded Costs table.

**Duquesne**

**STRANDED COST CALCULATION - REGULATORY ASSETS ($000) NPV $1999**

| | Company Claim | Adjustments | Adjusted Amount | Note/Source |
|---|---|---|---|---|
| | Net | | | |
| Regulatory Tax Receivable (SFAS 109) | 179,000 | 179,000 | 0 | John Moot, Skadden, et.al. (Company Claim). |
| Post-2005 Unamortized Debt Costs | 19,040 | 19,040 | 0 | Ibid |
| Pre-2006 Unamortized Debt Costs | 9,800 | 0 | 9,800 | Ibid |
| Deferred Rate Synch. Costs | 23,500 | 23,500 | 0 | Ibid |
| Deferred Employee Costs | 13,830 | 13,830 | 0 | Ibid |
| Deferred Nuclear Maintenance | 1,900 | 0 | 1,900 | Ibid |
| DOE Decommissioning | 3,250 | 0 | 3,250 | Ibid |
| Deferred Coal Costs | 13,500 | 13,500 | 0 | Ibid |
| Deferred Caretaker Costs | 3,920 | 3,920 | 0 | Ibid |
| BV2 Training Costs | 1,580 | 0 | 1,580 | Ibid |
| Low Level Radioactive Waste | 2,270 | 0 | 2,270 | Ibid |
| Coal Cost Equalization | 120 | 0 | 120 | Ibid |
| Pre-Accrued Nuclear Outages | 10,290 | 10,290 | 0 | Ibid |
| SFAS 106 Deferral | 1,920 | 1,920 | 0 | Ibid |
| Deferred Fuel Costs | 6,730 | 0 | 6,730 | Ibid |
| Other Regulatory Assets | 530 | 0 | 530 | Ibid |
| BV2 Sale/Leaseback Premium | | | 0 | Ibid |
| Gain on Sale Leaseback Tax Effect | 55,130 | 0 | 55,130 | Ibid |
| Deferred Rate Synch. Tax Effect | 210 | 210 | 0 | Ibid |
| Beaver Valley 2 Tax Effect | 170 | 0 | 170 | Ibid |
| SFAS 109 Plant | | | 0 | Ibid |
| Other Transition Expenses | 10,590 | 0 | 10,590 | Ibid |
| Net Present Value | 357,280 | 265,210 | 92,070 | |
| | | | | |
| PUC Jurisdictional Percent | 99.9% | | | |
| Deferred Taxes on Regulatory Assets | 105,520 | 105,520 | 0 | Does not appear in company claim. See DJC-10. |

**BEFORE THE**
**PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**CERTIFICATE OF SERVICE**

I hereby certify that I have this day served a true copy of the foregoing PUBLIC VERSION of the Main Brief of Hospital Shared Services And Administrative Resources, Inc. on the service list in this proceeding in accordance with Section 1.54 of the Commission's regulations.

Dated this 10th day of February, 1998.

Robert M. Lamkin
Andrews & Kurth L.L.P.
A Registered Limited Liability Partnership
1701 Pennsylvania Avenue, N.W.
Washington, D.C. 20006
TEL: (202) 662-2700
FAX: (202) 662-2739

An Attorney for Hospital Shared Services and Administrative Resources, Inc.

LAW OFFICES
WOLF, BLOCK, SCHORR AND SOLIS-COHEN LLP
212 LOCUST STREET
SUITE 300
HARRISBURG, PA 17101-0213
(717) 237-7160
FACSIMILE: (717) 237-7161

DOCUMENT FOLDER

ROBERT J. LONGWELL
DIRECT DIAL: (717) 237-7173
E-MAIL: RLONGWELL@WOLFBLOCK.COM



February 9, 1998

**VIA HAND DELIVERY**
James McNulty, Secretary
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105-3265



RE: Duquesne Light Company Application to Approve Restructuring Plan Pursuant to 66 Pa. C.S. §2806(d)
Docket No. R-00974104

Dear Mr. McNulty:

Enclosed for filing please find an original and nine copies of the Main Brief of Enron Power Marketing, Inc. As indicated on the attached Certificate of Service, copies of this document are being served this day on the parties in the manner indicated.

Please contact me if you have any questions with respect to the enclosed.

Very truly yours,

Robert J. Longwell
For WOLF, BLOCK, SCHORR and SOLIS-COHEN LLP

DC/lww
Enclosure

cc: Hon. John Corbett, Jr. (w/enc.)
All Parties of Record (w/enc.)

DSH:11126.1

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

| | | |
|---|---|---|
| Pennsylvania Public Utility Commission | : | |
| | : | |
| v. | : | |
| | : | Docket No. R-00974104 |
| Duquesne Light Company | : | |
| Application to approve Restructuring Plan pursuant to 66 Pa. C.S. § 2806(d) | : | |

ORIGINAL

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**MAIN BRIEF OF ENRON POWER MARKETING, INC.**

---



Daniel Clearfield
Gerald Gornish
Robert Longwell
Wolf, Block, Schorr and Solis-Cohen LLP
212 Locust Street, Suite 300
Harrisburg, PA 17101



Dated: February 10, 1998

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APPENDIX A

## STATEMENT OF THE CASE

Duquesne Light Company ("Duquesne") filed its Application for Approval of Restructuring Plan ("Application" or "Restructuring Plan") under Section 2806 of the Public Utility Code, part of the Electricity Generation Customer Choice and Competition Act ("Electric Competition Act" or "Act"), 66 Pa. C.S. § 2801, et. seq., on August 1, 1997, commencing these proceedings in the above-captioned docket. Following a telephonic prehearing conference on September 4, 1997, an informal telephonic conference was held to determine a litigation schedule. The schedule set at that time exceeded the nine-month requirement for review of the restructuring plan by the Commission set by 66 Pa. C.S. § 2806(f); however, the parties agreed to waive that statutory deadline.

A modified discovery procedure to be followed in this proceeding was established pursuant to the First Prehearing Order of Administrative Law Judge (ALJ) John Corbett, issued on September 12, 1997. Approximately 25-30 intervenors requested permission to enter the proceeding or had attended the prehearing conference, and their intervention was approved subject to Duquesne's protesting their intervention within five days of the ALJ's First Order. The parties proceeded with discovery and several rounds of written testimony were submitted by various litigants in conformance with the established procedural schedule.

Evidentiary hearings were held in Pittsburgh between December 15 and December 18, 1997, during which witnesses for Duquesne were cross-examined. Further hearings originally scheduled to be held during the week of January 5-9, 1998 were canceled after the parties agreed to permit intervenor testimony to be entered into the record by stipulation. The list of testimony and exhibits sponsored by Enron and its witnesses is attached

as Appendix "A" to this Brief. The Ninth Interim Order Closing the Record was issued on January 23, 1998. Requirements for main and reply briefs were established by the ALJ in his Fifth Prehearing Order and Ninth Interim Order. This Main Brief is submitted in compliance with the ALJ's directive.

## I. INTRODUCTION AND SUMMARY OF ARGUMENT

Through its decision in this proceeding, the Commission will establish a restructuring plan to govern Duquesne's transition from a monopoly environment in its service territory to a competitive retail market for generation supply pursuant to the mandates of the Electric Competition Act. However, if Duquesne has its way, as reflected in its proposed Restructuring Plan, the transition will not be to a competitive market, with all of its associated consumer benefits, but instead will lead to an unregulated monopoly. While such a result may be in the best interests of Duquesne's stockholders, it will be nothing short of disastrous for electric customers in its service territory.

Duquesne's Restructuring Plan advocates measures which erect barriers to entry and impede the development of a meaningful competitive environment as mandated by the General Assembly. Left to its own measures, Duquesne would have the Commission approve a plan which assures little or no competition in its service territory until it has recovered every dime of its claimed level of stranded and transition costs.

The linchpin of Duquesne's "no competition" Restructuring Plan is its demand to establish its annual stranded cost recovery level as the residual of what it claims as the generation credit: an understated "market price" for power, derived from price offers received in a solicitation for the sale of wholesale power, without costs particular to serving retail customers.

With the difference between its low ball market price and its claimed total generation revenue requirement being claimed for recovery as "stranded", Duquesne will recover all of its stranded costs while, at the same time, competition will be stymied in its service territory because, by all accounts, Duquesne's claimed "RFP" derived generation credit is below every other estimate of the cost the suppliers will have to incur to deliver power to customers in Duquesne's service territory.

Suppliers thus would be forced to sell power at a loss just to match the generation credit offered in Duquesne's plan. If they wish to offer savings to make their service attractive vis-a-vis Duquesne's rates — obviously necessary for customers to consider it in their interest to switch from the company that has always served them — the losses would be even more catastrophic. The result will be that suppliers simply won't offer service to most customers, and most of Duquesne's customers — certainly their residential and small commercial customers — will have choice in name only. Competition would be hard pressed to emerge after this period in the face of a competitor — Duquesne — which has had a five-year headstart in building a war chest and revising its operations to respond to open access.

However, the Act envisions and, in fact, requires a much different paradigm. Under the Act, an electric distribution company ("EDC") is not entitled to one dime of transition or stranded costs unless and until it opens up its generation supply market to competition.[1] Moreover, the Act requires that in restructuring electric utilities, "the Commission shall allow

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[1] Under 66 Pa. C.S. § 2803, "transition or stranded costs" are costs "which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market . . . ." Obviously, absent a restructuring plan which enables a competitive generation market, neither Duquesne nor any other EDC is entitled to any transition or stranded costs.

customers to choose among electric generation suppliers in a competitive generation market through direct access."[2] Simply put, Duquesne cannot have it both ways by asserting a claim to recover approximately $1.9 billion (NPV) in transition and stranded costs and at the same time proposing a market structure that would assure that competition is non-existent while it does so.

The record in this case establishes that, if permitted to develop, a fully competitive generation supply market will deliver enormous benefits to the consuming public in the form of higher quality service, lower prices and innovative products. It will provide real and lasting savings, not just temporary or shallow reductions. However, such consumer benefits are possible in Duquesne's service territory only if the Commission makes far-reaching modifications to Duquesne's proposed Restructuring Plan[3] in virtually every area to remove the anti-competitive provisions which, if permitted to become effective, will impede development of the fully competitive environment the Act demands.

Summarily, and as set forth in more detail below, Enron requests that the Commission make the following modifications to Duquesne's proposed Restructuring Plan:

- The Commission should establish generation or "shopping" credits that assure market entry for all classes of customers by requiring unbundling of transmission, distribution and generation rates, a levelized competitive transition charge ("CTC") rate design, and determination of the level of transition and stranded costs consistent with the Commission's Restructuring Order for PECO Energy Company ("PECO").[4]

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2 66 Pa.C.S. §2804(2) (emphasis added).

3 Under 66 Pa. C.S. §2806(f), the Commission may modify an EDC proposed restructuring plan to conform it to the requirements of the Act and the evidence.

4 Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code, R-00973953 (December 23, 1997), Reconsideration Order (January 16, 1998) and Order on Compliance Filing (February 5, 1998) (referred to respectively as "PECO Restructuring Order," "PECO Reconsideration

- The Commission should modify Duquesne's allocation of costs to assure that only transmission and distribution ("T&D"), not generation related costs, are recovered in Duquesne's T&D rates using the Company's actually realized rate of return, and that only qualifying transition or stranded costs are recovered through the CTC.

- The Commission should adopt an accelerated phase-in and phase-in procedures consistent with the PECO Restructuring Order.

- The Commission should modify Duquesne's proposed code of conduct, and should establish a code to preclude any potential for anti-competitive behavior between Duquesne and its generation supply affiliates or divisions by adopting the Portland General Electric Company's ("PGE") Code of Conduct or, alternatively, the Code of Conduct ordered by the Commission in the PECO Restructuring Order as a statewide interim Code of Conduct.

- The Commission should modify Duquesne's Restructuring Plan to require full embedded cost unbundling of and competitive entry into revenue cycle or "non-wire" services, like billing, metering and customer services, thereby allowing customers to take advantage of innovation and improvement without paying twice for these services.

- The Commission should modify Duquesne's proposed tariff to allow suppliers to act as agents for customers in the ordering and provisioning of T&D, revenue cycle services and generation supply services.

- The Commission should modify Duquesne's plan relative to other issues, like customer selection procedures, treatment of partial payments, universal service and customer education to parallel Enron's proposed language.

Overall, it is critical for the Commission to take the steps outlined above to establish a restructuring that will enable the development of a robust competitive retail market in Duquesne's service territory. Otherwise, the Commission will fall short of complying with the

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Order" and "PECO Compliance Filing Order").

Act's requirements and will not deliver the Act's intended benefits to consumers and businesses.

## II. PHASE-IN OF CUSTOMER CHOICE

### A. Method of Customer Selection

Duquesne's proposed method of customer selection is inconsistent with Commission policy and would produce an unfair entry process. Duquesne's proposal is to select customers on the basis of zip code-based geographic areas of choice ("GACs").[5] Larger commercial customers and industrial customers would be phased in on the basis of SIC code-based market segments.[6] In both cases, the groupings would be prioritized on the basis of expressed interest in the Pilots.[7]

There are several reasons to reject Duquesne's proposal. First, Enron witness Muench pointed out the variety of problems that would result when phase-in is based upon geographic criteria. Chief among them is the probability that Duquesne's process would result in far less than 33% of Duquesne's customers (or 66% if the first two phase-in steps are conducted more or less simultaneously, as discussed below) having access to customer choice.[8] Moreover, a "first come-first serve" approach — the preferred method under the Electric Competition Act[9] — clearly would assure all customers an equal and fair ability to participate in direct access and, at the same time, guarantee that the entire initial 33% (or 66%) of Duquesne's

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5 Duq. St. 6 at 3.

6 Id. at 4.

7 Id.

8 Enron St. 4.1 at 11-12.

9 66 Pa. C.S. § 2806(b)(4).

load would be subject to choice.[10] The GAC and SIC method advocated by Duquesne simply will indiscriminately prevent customers who desire to participate in the competitive marketplace from attempting to take advantage of competition. Small commercial customers would also be disadvantaged from one neighborhood to another.[11] Moreover, prioritizing customers on the basis of their participation in the Pilots does nothing to eliminate any possible "unfairness" caused by a disparity in information or opportunity to participate; a customer could easily have failed to attempt to participate in the Pilots due to initial ignorance about electric competition, but may now be very interested only to find his/her opportunity delayed because of his (and his neighbors') failure to respond to the Pilot. It was for some of these reasons that the Commission rejected the "GAC/SIC process" as it was proposed by Duquesne in the Pilot proceeding.[12]

For all of these reasons the procedure established by the Commission in the recent PECO proceeding clearly is the most reasonable method of customer selection and should be adopted. The PECO Restructuring Order adopts the method used for the Pilot to allow customers to include themselves in direct access. Residential and small commercial customers will respond to the opportunity to be eligible for direct access. If more than the number initially permitted (two-thirds) of Duquesne's load requests eligibility, a lottery will select the customers who will be eligible for the first phase (66% as described below).[13] For industrial customers the

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10 Enron St. 4.0 at 20-21.

11 Id. at 20.

12 Re: Petition for Approval of Retail Access Pilot Program Pursuant to 66 Pa. C.S. § 2806(g) (Duquesne Pilot Order) P-00971175 (Opinion and Order entered Aug. 29, 1997) at 25-28.

13 PECO Restructuring Order at 47-49; PECO Reconsideration Order at 21-23.

Commission mandated that 66% of each customer's load be eligible for the first combined phase-in.[14] If more than 66% of industrial customer load volunteers for the first two phases, 66% of the load of all industrial customers volunteering will be included.[15] This customer selection process is the fairest approach to this issue, is consistent with the Act and will promote the full and expeditious development of a competitive market. It should be adopted for Duquesne.

**B. Timetable for Phase-In**

In its proposed restructuring plan, Duquesne proposed a phase-in period of two years in which 33% of the peak load of each customer class would be available for direct access on January 1, 1999; another 33% on January 1, 2000; and the remaining 33% on January 1, 2001.[16] Presumably, at the time of its application filing and during record development in this proceeding, Duquesne presumed that there would be a three-year phase-in for all EDCs in the Commonwealth.

However, in the PECO Restructuring Order, the Commission ordered an accelerated phase in for PECO. In reaching its determination after quoting the language of 66 Pa.C.S. § 2806(b), the Commission stated as follows:

> The language in the Act quoted above permits the Commission to adopt a more rapid phase-in schedule than proposed by PECO. We conclude that the most rapid phase-in permitted under the Act is in the public interest and should be adopted. PECO is directed to conduct an open enrollment period beginning March 1, 1998. The first 33% of customers to volunteer from each tariff class may shop

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14 Id.

15 Id.

16 After accounting for the inclusion of Pilot customers in the first third. Duq. St. 6 at 3.

> on January 1, 1999. PECO shall notify such customers through a Commission approved letter. Up to 66% may volunteer to shop as of January 2, 1999 . . . . All customers will have the opportunity to shop as of January 2, 2000.[17]

While not every resolution of every issue in the PECO case applies to this case, certainly the length of the phase-in period is a determination that should apply consistently to each EDC service territory throughout the Commonwealth. One can only imagine the public confusion if the length of the phase-in period varies from service territory to service territory. The Commission's decision in the PECO case to accelerate the phase-in because such acceleration is in the public interest is a sound policy decision permitted by the clear language in the Act,[18] and will bring the benefits of competition to more customers sooner. The Commission's determination in that case is equally applicable to the case at hand and should be considered a binding precedent as to this proceeding.

## III. TRANSMISSION AND DISTRIBUTION RATES; UNBUNDLING ISSUES

### A. Introduction

A key part of the unbundling process is the establishment of just, reasonable and nondiscriminatory transmission and distribution rates which would be charged to all electric generation customers upon the implementation of restructuring (with the caveat that the

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17 PECO Restructuring Order at 47-48.

18 See, 66 Pa. C.S. § 2806(b). The language states that "as of January 1, 1999 [one-third of customers shall have the opportunity to shop, and] as of January 1, 2000, a maximum of 66% of the peak load of each customer class shall have the opportunity for direct access" [and "as of" January 1, 2001, 100% are phased in] (emphasis supplied). The only limitation in the statute is that no more than one-third of customers will have direct access as of January 1, 1999 and no more than two-thirds will have direct access by January 1, 2000. Providing access to an additional one-third as of January 2, 1999 and 100% access by January 2, 2000 is consistent with this language.

transmission rates established in this proceeding involve the current charges within the bundled rates, and in the future, all customers will be charged the unbundled retail transmission rates established by the Federal Energy Regulatory Commission ("FERC")).

Duquesne's proposal to "unbundle" the portion of its present rates associated with "Distribution" must satisfy the dual requirements of Chapter 13 of the Public Utility Code[19] and, at the same time, the Electric Competition Act, that Duquesne's rates be unbundled and categorized as Generation, Transmission and Distribution, and "Other Services."[20] Further, Duquesne's Distribution rates and its unbundling are capped at their January 1, 1997 levels for a period of 54 months starting January 1, 1997.[21]

As more fully detailed below, Duquesne's T&D rates fail to satisfy these standards in several respects and require revision. In summary, the revisions required are as follows:

1. The Company has inappropriately allocated 100% of the cost of sales, customer information and assistance and uncollectible accounts expense to the distribution function even though these costs are either all or substantially related to the retail sale of generation services.

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19 See, PECO Restructuring Order at 61. ("[W]e note that the PECO's T&D rates continue to be subject to Chapter 13 of the Public Utility Code and, subject to the Act's rate caps, parties may challenge existing rates.") As noted, Duquesne's transmission rates are FERC regulated and those levels are not at issue here. The only issue with respect to transmission service is the identification of the cost associated with transmission service for the purpose of separating it from the rest of the bundled rate. See, PECO Compliance Filing Order at 9.

20 66 Pa. C.S. § 2804(3); PECO Restructuring Order at 51.

21 66 Pa. C.S. § 2804(4)(i); PECO Restructuring Order at 52.

2. The Company has not fully unbundled transmission ancillary services from its current generation rates, and reduced it generation book value by that amount.

3. Duquesne's proposed unbundled distribution services do not appropriately separate the portions of those costs associated with "non-wire services" from the "wires" portion of the charge.[22]

4. Duquesne has failed to submit a "supplier" or distribution services tariff which establishes the rules and delivery service rates to electric generation suppliers who will be responsible for making all necessary arrangements (without duplicating the services and terms and rates already included with Duquesne's FERC transmission tariff) for individual or aggregated end-user customers and which includes voltage-based rather than class-based rates.

## B. 1996 Test Year Cost of Service

The starting point for identifying appropriate distribution rates for Duquesne is the Company's 1996 cost of service study which is used as the basis for allocating all of the Company's costs between generation, transmission and distribution. The study can also be used to separate wire from "non-wire" services. Duquesne's methodology contains a number of errors.

1. Functionalization. Duquesne utilized a surrogate to assign the bulk of its administrative and general expenses and general plant to the three categories, Generation, Transmission and Distribution. The surrogate used was the percentage of labor expenses associated with each of the three categories. As Enron witness Reising explained, while this

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22 This issue will be discussed in a separate section of this Brief, see, section IX.C.1. infra.

proxy method is minimally adequate, a detailed functional cost study[23] should be performed to determine the precise association of Duquesne costs with the three functional categories. Enron recommends that the Commission's Order direct Duquesne to conduct such a study and submit it at a later date so that distribution rates may be revised.

2. Allocation of Sales, Customer Information and Assistance and Uncollectibles. Notwithstanding the above, Duquesne's cost of service study also inappropriately assigns several cost of service elements entirely to the "distribution" function even though the costs are obviously associated with all aspects of Duquesne's service. The cost elements inappropriately assigned are: (a) sales expense; (b) customer information and assistance expense; and (c) uncollectible accounts expense.

(a) Sales Expense. Sales expenses are incurred to promote the sale of additional energy to retail customers. Such costs obviously must be assigned to the generation portion of Duquesne's operations to avoid cross subsidies.[24] Duquesne's attempt to charge 100% of these costs — some $4.5 million[25] — via its distribution rates not only unfairly charges distribution customers for costs for which they are not responsible but also provides an unfair advantage to Duquesne's generation supply activities. By foisting its sales expenses on distribution customers, Duquesne will be able to sell energy services in the market without

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23 Enron St. 2 at 6-7. A functional cost study is a study in which a detailed analysis is made of cost categories to determine whether the cost category is associated with the Generation, Transmission or Distribution functions. Such a detailed study would also examine whether a particular cost category could be reduced or transferred to an unregulated subsidiary.

24 Enron St. 2.0 at 8.

25 Duq. Exh. JAL-1B, p. 16.

having to recover these costs in the rates that it charges to customers.[26] As several Duquesne witnesses admitted, all participants in the market, including Duquesne's competitors, must recover all costs (including a profit) associated with providing retail generation services in the charges they make to customers.[27] Such a blatant cross-subsidy cannot be condoned either by general ratemaking principles or the Electric Competition Act.[28] Duquesne's contentions to the contrary simply do not hold water.[29]

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26 Id.

27 See, Tr. 526-27.

28 Under traditional cost of service principles, costs have been allocated to classes or functions on a cost causation basis. The Commission regularly has insisted that if a class is not responsible for a particular cost it should not be included in determining the rates for that class. Similarly, the Electric Competition Act states that distribution shall be unbundled 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). Assigning 100% of these costs to the Distribution system means that Duquesne's implicit cost of using its distribution system to deliver power to customers will not contain any of these costs and its use will not be "comparable."

29 It is difficult to understand how Duquesne's sales expense can be reasonably related to any portion of the T&D function; distribution service is completely exempt from competition: no sales expenses will be incurred to sign up a customer — beyond that necessary to "sell" the energy itself — which is a generation related cost, not a cost associated with distribution. More importantly, it was Duquesne's obligation to support its claim that there is sales expense that will be associated with T&D "sales," but it did not. More likely, as Mr. Reising pointed out, these costs will be associated with Duquesne's continued provision of regulated generation services (as provider of last resort) or will be eliminated (as no longer necessary) or will be assigned to non-regulated business units, for example, appliance sales, repair or retail energy sales. Enron St. 2.1 at 2. The "avoidable" nature of sales as well as customer assistance expense (discussed next) is supported by the fact that Duquesne itself recognized that its Administrative and General expenses support all three of the Company's present functions (Tr. 625) and that it would be able to avoid an allocated share of these expenses if it were to close any of its power plants. Tr. 599.

(b) Customer Information and Assistance Expenses. A second category of misallocated expenses are those included in USOA accounts 908 and 909: Customer Assistance and Informational and Instructional Advertising Expenses. Duquesne, without explanation, included 100% of these costs as distribution related costs.[30] A review of these costs, however, makes it clear that they relate to promoting and encouraging the use of electric energy, either generally or from a safety or conservation standpoint. For example, they include the expenses for activities associated with "advice regarding the most efficient use of electric equipment, demonstrations of the economical and efficient use of electric service, and engineering and technical advice to promote efficient and economical use of utility services."[31] Indeed, the review of the accounts associated with these expenses did not indicate that any of the costs are directly associated with distribution-related delivery system activities.[32] While some of the costs booked into either of these accounts might be associated with such items as distribution safety matters or other system wide activities, Duquesne made absolutely no attempt to investigate or demonstrate what portion of its customer information and assistance expenses are properly associated with delivery system issues as opposed to issues associated with the use of energy itself.[33] Again, by allocating 100% of these costs to the distribution function Duquesne allows its generation activities to receive a "free ride" and avoid expenses that other competitors will have to bear. Or, stated otherwise, Duquesne's generation energy services will receive the

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30 Enron St. 2.0 at 8-9.

31 Id.

32 Id.

33 Id.

benefit of these expenses without having to incorporate them into the prices it charges its customers.[34]

(c) Uncollectibles Expense. Duquesne has included 100% of its uncollectible expense, over $11 million — almost 1/3 of its total customer accounts expense — as a distribution-related cost even though it is associated with uncollectibles for its entire retail operation. Uncollectible expenses are obviously associated with all services, including generation services, and should have been allocated on the basis of the percentage that the production, transmission, distribution revenue requirements bear to the total Company revenue requirements.[35] Failure to do so again provides a completely unwarranted and illegal subsidy to Duquesne's generation sales operations.

Uncollectibles are a legitimate expense of doing business, and all marketers and suppliers will incur them and attempt to recover those expenses in the rates that they charge to customers. If Duquesne's position is accepted, it alone in its service territory will have the luxury of having its entire uncollectibles expense repaid through non-bypassable charges for monopoly services and will not have to recover this amount in the prices it charges for generation.[36]

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[34] Duquesne's response to Mr. Reising's testimony on this allocation (or lack thereof) is to suggest that some part of customer assistance and information probably is associated with its delivery system. Duquesne St. 5-R at 28. Yet Duquesne's claims were backed up by nothing more than supposition and innuendo. Duquesne had the burden of proof to show that its proposed T&D allocation is reasonable; having failed to do so, 100% of these costs should be allocated to the generation function. Enron St. 2.1 at 2.

[35] Enron St. 2.0 at 10.

[36] Id. Duquesne's response to Mr. Reising's testimony was that it was "reasonable" to allocate 100% of its uncollectible expense to the distribution function because in its role as "Provider of Last Resort" it would likely end up with a far greater level of bad debt

This evidence clearly demonstrates that sales and customer assistance and informational advertising expenses should be allocated 100% to the generation function of Duquesne's functional separation study. Uncollectibles should either be allocated to each of the functional categories or, to the extent that energy suppliers or third parties other than Duquesne as the EDC provide billing services and take credit risks (for example, if the Commission permits suppliers to act as agents for customers and provide a single bill with all charges included), uncollectible accounts expense should be unbundled and removed and not be charged in Duquesne's distribution rate for those customers at all.[37]

Finally, it would be entirely inappropriate once these costs are allocated to the generation portion of Duquesne's functional unbundled rates, to simultaneously add them to the Company's stranded cost recovery allowance. This is because such costs, as the record clearly indicates, are costs that will be incurred by all suppliers and each supplier will make an effort to

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expense than suppliers. Duq. St. 5-R at 29. Whether true or not (and in light of a supplier's obligation to accept customers in accordance with Chapter 56 — the same rules that apply to Duquesne — but without the authority to terminate from the system a customer that fails to pay their charges, suppliers may well have greater proportionate uncollectibles than EDCs), the fact is that a share of uncollectibles should be assigned to Duquesne's PLR generation service, and not solely to its distribution service. Mr. Lahtinen failed (or refused) to understand that the two are separate and that customers that purchase only distribution services from Duquesne (and receive generation services from a competitive supplier) should not be forced to subsidize uncollectible expense associated with Duquesne's electric generation service whether it is PLR service or not.

Mr. Lahtinen also launched a general criticism of Mr. Reising's cost of service study, claiming that it contained errors and "circular references" which made Reising's recommended cost allocations unreliable. As Mr. Reising testified, for the most part Mr. Lahtinen's criticism is simply based upon a failure to understand the material and backup provided. Enron St. 2.1 at 3. Mr. Reising did identify a few minor calculation errors which Mr. Reising corrected in his surrebuttal testimony. Id. at 4.

37 Enron St. 2.0 at 10.

recover them in a competitive environment. As such they do not satisfy the definition of "stranded costs" in the Electric Competition Act.[38] Moreover, allowing Duquesne to add to its stranded cost recovery the costs removed from its T&D assignment would simply perpetuate the unfair competitive marketing advantage that Duquesne sought to obtain by assigning these costs to T&D in the first place. Finally, such a reallocation does not satisfy the Electric Competition Act's requirement that distribution and transmission rates be established justly, reasonably and nondiscriminatorily and charged in a manner comparable to the charges that Duquesne will incur in providing generation services.[39]

### C. Required v. Realized Rates of Return

In addition to the revisions to the allocation of costs described above, Duquesne's proposed level of T&D costs needs to be adjusted to eliminate Duquesne's attempt to inflate its calculation by using its so-called "required" rate of return rather than its actually realized rate of return on its T&D costs as of January 1, 1997. As Mr. Reising testified, Duquesne's attempt to puff up the costs associated with Distribution service amounted to a de facto attempt to secure a rate increase for this portion of its operations. This is obviously inappropriate and has been challenged as improper by a number of parties.[40] As all of these parties have pointed out, stating the cost of T&D at Duquesne's "pro forma" or claimed "required" rate of return increases those

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38 See, 66 Pa. C.S. §§ 2804(15), 2803.

39 66 Pa. C.S. § 2804(6).

40 Enron St. 2.1 at 6; OCA St. 2A at 5-6. Duquesne's attempt to inflate its T&D rates would increase the portion of Duquesne's rates not subject to competition. If the Commission continues to use the "PECO method" of unbundling, where the generation credit is the residual after subtracting non-generation charges, Duquesne's proposed method will increase the non-generation charges and, in turn, decrease the generation credit, producing even less competitive opportunity in Duquesne's service territory.

costs above the level actually incurred in the 1996 test year because the return level included in Duquesne's study is the level that Duquesne claims that it should be earning, not the amount that it actually did earn. The "required" return included in its study is precisely the type of return that would be included traditionally in a cost of service study allocating costs and revenues after accounting for a proposed rate increase (or an approved rate increase as reflected in a compliance cost of service filing). Obviously Duquesne has provided no testimony or evidence to justify such an increase for capital costs generally or for its T&D costs in particular. Moreover, because Duquesne's present rates are capped at January, 1997 levels, Duquesne's maneuver means that the total T&D rates would be set at a level higher than the rate level implicit in Duquesne's rates as of that date. This is clearly contrary to the Electric Competition Act which states as follows:[41]

> (i) For a period of 54 months from the effective date of this chapter or until an electric distribution utility is no longer recovering its transition or stranded costs through a competitive transition charge or intangible transition charge and all the customers of an electric distribution utility can choose an alternative provider of electric generation, whichever is shorter:
>
> * * *
>
> (B) For customers who purchase generation from a supplier other than the electric distribution utility, the charges of the utility for non-generation services that are regulated as of the effective date of this chapter, exclusive of the competitive transition charge and intangible transition charge, shall not exceed the non-generation charges that have been approved by the commission for such service as of the effective date of this chapter.

[41] 66 Pa. C.S. § 2804(4)(i)(B) (emphasis added).

Accordingly, Duquesne's attempt clearly violates the above statutory cap on "non-generation services."

Duquesne halfheartedly attempted to justify its use of its "required" or "pro forma" rate of return instead of the return it actually earned in its authorized rates by claiming that it was free to hike its T&D rates above its January 1997 realized level because no unbundled T&D rates existed at January 1997.[42] But no electric company had unbundled T&D rates as of January 1997 and Duquesne's self-serving interpretation would render the entire non-generation rate cap a nullity.

As the Commission itself indicated, "[the generation and non-generation rate cap provisions] clearly provide that the charges for generation, transmission and distribution which result from [the restructuring] proceeding may not rise above those levels which have been approved by the Commission as of January 1, 1997."[43] Duquesne's attempt to increase the rates is therefore unlawful and should be rejected.

**D. Distribution Losses**

Duquesne's revised position on line losses is that they should be recovered as part of the "delivered market price" and arranged for and paid by the supplier.[44] It therefore adjusted its cost of service study to account for this change. As discussed by Enron witness Reising,[45]

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42 Duq. St. 5-R at 36.

43 PECO Restructuring Order at 52 (emphasis added). It is also important to note that neither PECO nor any other electric utility of which Enron is aware attempted to inflate its T&D rates by injecting a rate increase for T&D rates by using a "target" rate of return.

44 Enron St. 2.0 at 11.

45 Enron St. 2.0 at 11.

line losses are generation related and should be recovered as a separate charge to enable suppliers to competitively procure this service if they wish to do so.[46] On the issue of transmission line losses, as OCA witness Ms. Smith's testimony indicates, Duquesne intends to charge for transmission line losses through its FERC tariffs. As these costs are unbundled, again, the overall stranded costs must be reduced.

**E. Ancillary Services**

Duquesne's position regarding the unbundling of ancillary services is that it will allow suppliers to competitively procure ancillary services pursuant to standards and restrictions contained in FERC Order 888.[47] Order 888 requires transmission providers to permit their customers to self-provide ancillary services to the extent that it is technically feasible under applicable regional reliability council standards. Enron agrees that this position is the correct one and commends Duquesne for willingness to follow the FERC approach.

Duquesne also recognizes that it is necessary to ensure that retail choice customers are not charged twice for ancillary services that they choose to purchase from an alternative supplier. In order to assure that this is not the case, Duquesne has proposed that customers will receive an annual credit for revenues collected from suppliers, net of any additional expenses incurred.[48] Enron agrees with Duquesne that it is important to assure that

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46 Id. Moreover, to the extent that distribution or transmission related line losses were included as a cost of generation, these costs must be removed from the Company's calculation of its generation revenue requirement. If this is not done, Duquesne's stranded cost allowance would be overstated to the extent that a "margin" type analysis — such as that recommended by OCA — is utilized.

47 Duq. St. 7-R at 3.

48 Duq. St. 5-R at 19.

customers are not charged twice for the same service and thereby penalized for choosing an alternative supplier. However, Enron does not agree that the appropriate mechanism is through an end-of-the-year "market based" credit. Rather, the transmission related portion of the rate should be unbundled to recognize the delivery of those services by an alternative supplier. Moreover, the credit should be based upon the embedded cost of the ancillary service established by Duquesne's cost of service study.

To assure implementation of the above, the Commission should direct Duquesne to calculate the embedded generation cost of ancillary services, and this value should be deducted from the company's generation revenue requirement.[49]

In addition, Enron agrees with the MAPSA arguments on Imbalance Charges and Scheduling Charges as set forth in this section of MAPSA's brief. Moreover, these costs are already contained within the FERC tariffs, and should not be re-applied to suppliers by Duquesne in an attempt to limit market opportunities.

**F. Voltage-Differentiated Rates**

Enron has proposed a Distribution Services Tariff (DST) which will apply to suppliers who will be responsible for making all the necessary arrangement (acting as agent) for individual or aggregated end-user customers.[50] In conjunction with the DST, Enron has

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[49] This would be important if a "merger" based calculation of stranded costs (such as the OCA methodology) is utilized. The OCA calculation determines stranded costs by comparing the revenues that plant is predicted to generate compared to the revenue requirement if ancillary services are included in the generation revenue requirement. If those are removed, the generation revenue requirement would be reduced and stranded costs would be reduced as well. Duquesne should be required to reflect this change in its compliance tariff filing.

[50] Enron St. 2.0, Exh. PDR-6.

proposed that rate design and applicable rates be greatly simplified, with rates designed so as to reflect the characteristics of the customer's service, including voltage level, rather than historical identification by traditional "class" of service.[51] In the restructured industry, the important pricing distinctions between customers will be the timing of electricity consumption, the voltage level at which customers take service and whether that service entails single-phase or poly-phase facilities. This approach has a number of advantages, including the following:

- It results in a simplification of rates which better enables the customer to determine the basis for the charges imposed.
- It results in a more direct attribution of costs to the type of facilities actually used by the customer instead of the traditional class-differentiated rates.
- Most of the motivation for class rates has to do with generation-related costs, which will now be provided via a competitive market through which suppliers will be free to establish energy pricing mechanisms to meet specific customer needs and desires.[52]

To demonstrate its proposal, Enron provided a sample rate design calculation for Energy Delivery Services.[53] Revenue requirements attributable to Energy Delivery Services are summarized into customer- and demand-related categories, and are then further segregated by customer voltage level. Notably, in that example, the demand charge component for service at secondary voltage is cumulative in that it covers demand-related costs of transmission and primary and secondary voltage facilities.[54]

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51 Enron's proposed voltage based rates are reflected in Enron St. 2.1, Exh. PDR-10.

52 Enron St. 2.0 at 25.

53 Enron St. 2.0 at 26, Exh. 2, PDR-7.

54 Id.

Duquesne incorrectly contends that the rates proposed to be used in conjunction with the DST would cause cost-shifting.[55] Under the DST, the Supplier — acting as agent for end-users — is the customer. In that circumstance, historic customer class distinctions have little meaning. Where the Supplier is not acting as agent for the end-user and for default customers, Duquesne's class-based unbundled tariff would apply. Where the DST applies, what is important is that Duquesne as EDC is appropriately compensated in aggregate by the Supplier for distribution services rendered. The voltage-differentiated rate mechanism presented in Enron Exhibit 2, PDR-7 (revised in Exhibit 2.1, PDR-10), is a simple straightforward means to accomplish that objective.[56]

Enron's Distribution Service Tariff is new and different — admittedly. But it also better suits the needs of customers and allows Duquesne to track costs in a way that appropriately considers the new competitive environment. The Commission should order that it be adopted.

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55 Duq. St. 5-R at 33-34.

56 Enron St. 2.1 at 4-5. Duquesne also contends that allocating secondary and primary voltage facilities to transmission voltage customers can be justified on the basis of "cost of service principles" and that it would be unfair not to charge a customer taking service at transmission voltage for secondary and primary voltage facilities. (Duq. St. 5-R at 33-34). Either these customers should not be in the same rate class (Enron's voltage-differentiated rate proposal addresses this) or, if these two customers are part of the same rate class, there should be a credit to the transmission customer for the cost avoided by the utility of not having to build transmission-to-primary voltage substations, primary voltage lines, line transformers, secondary voltage lines and service drops. Enron St. 2.1 at 5.

### H. Conclusion

Enron's recommended Transmission and Distribution related costs were presented by Mr. Reising on Enron Exh. 2.1, PDR-8. This exhibit reflects the adjustments to remove generation related costs discussed above, and to correct the Duquesne study to reflect Duquesne's 1996 realized return rather than its target or proposed rate of return incorporated into Duquesne's study. This schedule also corrects certain minor errors contained in Mr. Reising's direct testimony. Proposed Distribution rates on a traditional class basis are shown on Enron Exh. 2.1, PDR-9. This cost of service results and proposed rates on a voltage-differentiated basis are reflected on Enron Exhibit 2.1, PDR-10. Duquesne should be directed to file rates in its Compliance Filing that conform to this cost of service allocation or to revise its own study and rates in accordance with the above recommendations.

## IV. TRANSITION OR STRANDED COSTS

Enron adopts the MAPSA arguments with respect to Section IV.A, B and F as set forth in MAPSA's brief. Enron also notes that issues related to Recovery of Stranded Costs (Section IV.F) and Methods of Stranded Cost Recovery (Section IV.F.3) are discussed below in Section V, Competitive Transition Charge.

## V. THE COMPETITIVE TRANSITION CHARGE

### A. Conceptual Disputes Regarding Calculation of CTC/CGC

Duquesne's methodology for unbundling of rates subtracts its proposed T&D rate from the present total and then sets the Competition Generation Charge ("CGC") at a wholesale

market price, calculated through an annual RFP conducted by Duquesne. The residual is then declared the CTC.[57]

The Company described its methodology thusly:

> . . . Duquesne has established rates for transmission, distribution and ancillary services, these charges will be deducted from current rates and the remainder will represent the maximum generation costs that can be recovered from customers.
>
> This residual amount will then be divided into two parts — a market-based generation component ("CGC") and an above market cost component. The CGC will be set using the market values from Duquesne's annual competitive bid solicitation; these market prices will be adjusted to account for differences among customer class consumption patterns, transmission losses, and Pennsylvania gross receipts tax. As adjusted, the market prices will be used to determine customer class CGCs and customer- specific CTCs. Customers will also receive annual credits for certain ancillary service revenues collected from retail suppliers.[58]

Whatever the level of the CTC residual, this is what Duquesne proposes to recover in transition or stranded costs subject to a true-up between 2002 and 2003.

Such an approach, while in furtherance of Duquesne's objective to impede competitive development until at least it recovers all of its stranded costs, is not consistent with the Act's objectives. First, Duquesne's proposed RFP approach would preclude the Commission from determining the level of Duquesne's transition or stranded costs in this restructuring proceeding and instead would leave that determination to future RFPs in violation of the Act.[59]

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57 Duq. St. 1 at 4.

58 Duq. St. 5 at 9. Thus, Duquesne's unbundling methodology makes the CTC the residual after deducting market price from the calculated generation portion of the rate. The CTC, therefore, is set precisely at Duquesne's version of market price.

59 This is explained in detail in the "stranded cost recovery section of MAPSA's brief, adopted by Enron in Section IV, above.

Second, by unbundling rates in a manner that treats the CTC rather than the CGC as the residual, Duquesne "pegs" the generation or shopping credit at Duquesne's RFP estimate of prevailing market prices for each year of the CTC recovery period, thereby turning the Electric Competition Act, and the PECO Restructuring Order approach on their heads.[60] Further, as MAPSA witness Russell concluded, under this scenario, "the proposed rates will stifle any nascent competitive options. Native loads of the existing franchised utilities will remain monopolistic markets throughout the 1999-2005 period and potentially well beyond that time into the future."[61]

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60 Duquesne's estimate of prevailing market prices for the residential class starts at 2.03 cents/kwh in 1999, however the actual market price used to establish the generation or shopping credit will be determined through a 1998 Duquesne RFP. Duq. Exh. JAL-15. By way of comparison, in the PECO Restructuring Order, the Commission estimated that the system wide shopping credit resulting from the decision would equal 4.46 cents/kwh in 1999 and the residential shopping credit was established at 5.23 cents/kwh. PECO Compliance Filing Order, Appendix D.

61 MAPSA St. No. 1 at 21. The Commission agrees. In evaluating the 2.8 cents/kwh system-wide generation credits contained in the PECO Partial Settlement, the Commission stated:

> . . . Yet even without the testimony of the opposing witnesses, we must at least conclude that the Partial Settlement's ECC [energy and capacity credits] will be below the market prices available to many customers from 2000 to 2003 and is therefore at odds with the record in this case.
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> * * *
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> Given the testimony of witness Hieronymous and other witnesses, the record can only support the conclusion that the Partial Settlement's EEC will protect PECO's present monopoly position at least for the period 2000 to 2003. As such, the Partial Settlement's Energy and Capacity Credits hinder creating a competitive retail electric generation market, a major purpose of the Act.

PECO Restructuring Order at p. 17-18.

Additional evidence of the unreasonableness of this CGC can be seen by comparing the calculated delivered market prices developed by OCA witness Smith. The system average delivered market price produced by the OCA model (including a share of generation A&G) is 2.529¢ per kwh which escalates to 4.062¢ in 2005.[62] Duquesne's system average CGC is 1.973¢ per kwh.[63] Thus, the generation credits produced by Duquesne's methodology would actually be below the likely delivered cost of power that suppliers will have to incur. Thus, simply to offer the same rate as the generation credit proposed by Duquesne, suppliers would have to sell to customers at rates below their cost. Of course, as the record here reflects, for suppliers to attract any level of customer interest, they must offer 10-20% savings on a customer's energy bill.[64] The evidence is overwhelming, therefore, that if Duquesne's plan is adopted, competition will literally be reversed (since the small number of pilot customers would actually see their bills increase when full direct access began to be phased in and would likely return to Duquesne).

Of course, this is exactly Duquesne's design. Unfortunately for Duquesne, but fortunately for the consuming public in its service territory, Duquesne's proposed plan is not compliant with the Act's mandate to open up the generation supply market to competition. Duquesne conveniently misinterprets the Act's paradigm and attempts to delay competition until after it has collected its claimed level of stranded costs rather than opening up its market as a condition of standard cost recovery as the Act demands.

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62 OCA Exh. LS-7.

63 See Enron Cross-Exam Exh. 3.

64 Tr. 1056-61.

Fortunately, the Commission has demonstrated through its PECO Restructuring Orders that it understands the Act's paradigm very well. Through its PECO decision, the Commission rejected PECO' "bottoms up" approach which treated the CTC as the residual and, instead, adopted a "top down" approach, which establishes the just and reasonable level of transition and stranded costs and treats the CGC as the residual. The Commission's approach is fully consistent with the Act and should be considered binding precedent in this proceeding. The Commission adopted a 5-step methodology as follows:

1) First, transmission and distribution rates are unbundled through evaluation of the EDC's proposed allocation of costs. Costs which are not properly allocated to transmission and distribution are reallocated to generation.[65]

2) Next, the level of known and measurable transition or stranded costs is calculated based upon evaluation of which costs in the EDC's claim "would be recoverable under a regulated environment, but which may not be recoverable in a competitive electric generation market."[66]

3) Once the Commission approved level of transition and stranded costs is established, a revenue requirement analysis is conducted to determine the level of CTC collections which are necessary to recover all transition and stranded costs. The revenue requirement analysis should include a cost of

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65 PECO Restructuring Order, at 49-63. In the Orders, the Commission reallocated a portion of PECO's Administrative and General ("A&G") costs to generation. One aspect of the Commission's Opinion and Order with which Enron strongly disagree is whether, once reallocated to generation, these A&G costs should be recovered as transition or stranded costs. In Enron's view, the law is clear that A&G costs associated with generation do not qualify as transition or stranded costs because these costs are fully recoverable in a competitive environment. Enron has appealed the PECO Restructuring Order to the Commonwealth Court on these grounds.

66 PECO Restructuring Order at 63-102. 66 Pa. C.S. § 2803. In determining the level of stranded costs, the Commission utilized the Office of Consumer Advocate's ("OCA") market price projections. While PECO and Duquesne depart in their approach to stranded cost calculation (PECO utilized an asset valuation approach and Duquesne proposed a "market sale" approach), both approaches require reference to market prices as the benchmark for evaluation of stranded cost levels.

capital equal to the EDC's long term debt rate, inclusive of all tax effects.[67]

4) The CTC rate is then designed to recover the CTC revenue requirement on a levelized basis, over a set period of time, on a "per kwh" basis assuming annual sales with a presumed growth rate (subject to reconciliation).[68]

5) The residual of T&D plus the CTC less the current bundled rates becomes the generation or shopping credit.[69] None of this residual should be converted into a short-term tariffed rate decrease[70] to be provided to consumers outside of the competitive marketplace since such short-term rate decreases are not consistent with the Act and restrain the development of a competitive market and the prospect of even greater savings that competition will bring.[71] Moreover, as the Commission held in the PECO

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67 PECO Restructuring Order at 103-09; PECO Compliance Filing Order at 6. Duquesne's long term debt rate is identified by the Company on the record as 7.57%; OCA Exh. MIK-5.

68 PECO Restructuring Order at 109-13. In the PECO case, the Commission established an 8½ year recovery period. However, the length of the recovery period should be established based upon consideration of the amount of stranded costs to be recovered — to balance the desire for as short a recovery period as possible with the need to establish generation or shopping credits which enable market entry and provide for the desired level of discounts for consumers.

69 As the Commission described its methodology, "The shopping credit is not a selected number. It is the number that results from the difference between a particular customer's total rate as of January 1, 1997 and the sum of T&D and CTC rates established pursuant to this order." PECO Restructuring Order at 42. It is noteworthy that this residual does not necessarily track market prices. Nor should it! While utilization of undependable long term market price projections is an unavoidable component of determining the level of stranded costs, nothing in the Act requires or even explicitly or implicitly links the unbundling of rates and the design of the CTC to market prices.

70 Contrary to OCA's apparent position. See OCA Exh. LS-7.

71 As the Commission stated in reaching this determination:

> Relying principally on changing rate tariffs to deliver price benefits to ratepayers will not foster the competitive retail electric market that the Act requires for all customers, not just the largest users. In fact, providing temporary rate cuts through tariffed generation rate reductions will leave the customers without a

Restructuring Order, if Duquesne wants to reduce its rates it has that authority under Chapter 13. Duquesne has not sought to reduce its rates during this restructuring case, when it had ample opportunity to claim that it was overearning.

6) Finally, the generation credit needs to be compared to the evidence of the cost of delivered power to assure that the Act's mandate that a competitive market develop will occur. If the generation credit will not produce the margin over costs necessary, several options are available including extension of the CTC recovery period and back-end loading of the CTC (with an equivalent NPV stranded cost level).

This 6 step "top down" approach closely tracks the Act by unbundling and designing distribution, transmission and generation rates in a manner which promotes, not impedes, the development of meaningful competition. In fact, it is arguably the only methodology which fully complies with the Act. There is absolutely no distinction which could reasonably justify departure from this approach in this restructuring proceeding. The approach of the PECO Restructuring Order as to the unbundling of distribution, transmission and generation rates and CTC design should be considered binding precedent and should be followed by the Commission in reaching a decision in this proceeding.

An example of application of the PECO methodology to Duquesne can be illustrated by comparing OCA's proposed T&D and CTC rates versus Duquesne's overall system average rate. OCA's proposed system average T&D rates are 2.113¢ per kwh, which would be assumed for each year of any CTC recovery period. Next, the determined stranded

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competitive market that is their only real protection under the Act. Indeed, once the temporary rate cuts expire, customers would experience the equivalent of a horrible hangover if little or no competition exists to provide the competitive benefits the Act intends.

PECO Restructuring Order at p. 43.

costs would be converted to an annual CTC, recovered over 8-½ years and levelized, allowing a return on the unamortized portion at Duquesne's cost of debt. If for illustrative purposes the levelized CTC is 2.3¢ (which implies a total stranded cost recovery consistent with the OCA recommendation recovered over 8 1/2 years), the CTC would be calculated as follows:

| | |
|---|---|
| Total Rate | 8.930[72] |
| T&D | 2.113[73] |
| Levelized CTC | 2.30 [74] |
| System Average Generation Credit | 4.517 |

If the various components were determined at the levels assumed, this resulting generation credit would likely be sufficient to permit suppliers to offer sufficient savings to allow the development of a competitive market in Duquesne's service territory.

## VII. SPECIAL CUSTOMER CLASSES

### A. Rule 4 Contracts and B. Riders 8 and 20

In the PECO Restructuring Orders, the Commission established standards governing the application and continuance of certain tariffs and riders available to special customer classes. As a general rule, the Commission required that "[a]ll existing tariffs shall remain available throughout the transition period and all special contracts shall remain in force, except as modified pursuant to this Opinion and Order or other tariff modifications approved by the Commission."[75] The Commission went on to conclude the following:

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72 OCA Exh. LS-7.

73 Id. The Commission should substitute individual class T&D rates as calculated by Enron witness Reising.

74 The levelized CTC would be calculated using the mandated recovery period and a rate of return equivalent to the Company's long term debt rate inclusive of all tax effects.

75 PECO Restructuring Order at 117.

1. No class of customers can be denied the opportunity to shop.

2. Interruptible service must be made available to all classes of customers.

3. The EDC "must file tariffs for distribution and transmission service applicable to customers in all classes who choose to shop."[76]

4. The EDC must allocate all existing discount provisions between the T&D and the generation components of the service and make each tariff or rider available as a T&D service with the allocated T&D discounts so that an eligible customer can purchase the discounted T&D service and still shop for generation service.

5. "Competitively priced" tariff offerings associated with generation will be eliminated and will remain available only to those customers who are not yet eligible for choice.

6. All existing EDC contracts will be honored and need not be assigned.

7. For contracts which do not preclude shopping, the EDC must unbundle the contract and allocate the discounts as set forth for interruptible tariffs above; and

8. No customers may avoid the CTC obligation.[77]

Clearly all of these standards reflect Commission policy decisions which should not vary from case to case or from EDC to EDC. Accordingly, they should be adopted by the Commission in this proceeding.

Duquesne's proposal to continue to offer its special contract "economic development rates" (Rule 4 and a Rider applicable to smaller customers)[78] to existing customers and in some instances to new customers may in some cases, be inconsistent with the

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76 Id. at 118.

77 Id. at 117-121.

78 Duq. St. 6 at 16-19.

Commission's policy as described above. Duquesne's rates should be consistent with the following:

- Special tariffs or economic development rates that Duquesne proposes to keep should be unbundled so that each rider or rate discount is available to customers for distribution service.[79] As Rule 4 Contracts are negotiated unbundling would not seem possible; however, Rule 4 contracts should be limited to distribution services only once direct access begins.

- Rates or Riders offering discounted generation service will not be available to customers not presently on such rates or to prospective customers once these customers are eligible for choice. (Such customers may receive discounted service from competitive suppliers or the unregulated affiliate or division of Duquesne itself.)

A customer is eligible for choice when a portion of its load is eligible to be supplied by competitive suppliers.

The general thrust of Duquesne's testimony appears to recognize the inappropriateness of continuing to offer special contracts or discount riders as they apply to generation.[80] This is appropriate, but the Commission should assure that all Duquesne "economic development" or discount rates comply with this directive. The Commission should limit the continued availability of these rates (as to generation) in favor of allowing customers to receive even greater benefits through a robust competitive market.

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79 Duquesne's plan appears to be that upon restructuring, it will assign economic development discounts to the CTC and that customers will be able to use alternative suppliers. This is appropriate and consistent with the PECO Restructuring Order. It should be implemented for all economic development rates Duquesne plans to continue to offer.

80 Duq. St. 6-R at 4.

## VIII. COMPETITIVE SAFEGUARDS

### A. Code of Conduct —The Commission Should Approve a Strong Code of Conduct to Prevent Anti-Competitive Behavior

Through passage of the Act, the General Assembly set forth a statutory foundation for bringing the full benefits of retail competition to Pennsylvania consumers and businesses. However, unless the Act is implemented in a manner which creates a "level playing field" between all generation suppliers — utility affiliates and non-affiliated suppliers alike — the promise of the Act will not be realized. While complete divestiture or structural separation is the preferred safeguard, at a minimum, complete functional separation enforced by a strong Code of Conduct is critical to meaningful competitive development.[81] Moreover, a strong Code is

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[81] The Commission and Enron witness Steffes are in total agreement on this point. As Mr. Steffes stated:

> [I]t is essential to the development of competition that the Commission establish a clear separation between the monopoly, regulated operations of Duquesne and its unregulated supplier and other affiliate roles . . . [Duquesne's] Code of Conduct does not deal in any way with the need for separation of Duquesne's regulated and unregulated activities or for the need to establish cost accounting and other cost separation rules.

Enron St. 1.0 at 7-8.

In strikingly similar fashion, the Commission states as follows in the PECO Restructuring Order:

> In our view, functional separation of regulated EDC functions and competitive generation functions is essential for the development of a vibrant competitive market. Structural separation through the establishment of fully independent entities is preferable whenever possible. With the development of competitive generation, the EDC must not have reason to treat its competitive suppliers differently than any other competitive supplier. Functional separation without legal separation must not provide a basis for

necessary regardless of whether Duquesne intends to offer "unregulated services to customers."[82] A Code of Conduct is necessary to insure that an EDC does not obtain or convey a competitive advantage to its generation service operation — whether it provides unregulated services or not. An EDC's control of monopoly distribution facilities — if unfettered — would permit it to manipulate information and access to such facilities in order to retard competition and enhance the market position of the EDC in its role as "provider of last resort."[83]

While it is clear that a permanent Code of Conduct will be established for all EDCs in the context of the Commission's rulemaking docket on this subject,[84] it is critical that the Commission establish in this proceeding an interim Code of Conduct for Duquesne which will be immediately effective. As Enron witness Steffes explained:

> A strong code of conduct is equally critical in the early stages of direct access. If EDCs are permitted to leverage the advantages inherited from their historic monopoly status and pass through or transfer those advantages to their affiliates, no unaffiliated supplier will be able to attract customers even if that supplier is offering lower priced or superior service.[85]

Direct access begins in January of 1999. Accordingly, marketing activity will commence only months after Commission entry of a final Duquesne Restructuring Order. While

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> any competitive advantage or opportunities for the marketing entity.

PECO Restructuring Order at 128.

82 Duq. St. 6 at 15.

83 Enron St. 1.0 at 7.

84 Competitive Safeguards - Proposed Rulemaking Order adopted January 29, 1998.

85 Enron St. 1.1 at 4.

Enron understands that the Commission has recently initiated a proposed rulemaking docket to codify a generic statewide code of conduct, it is likely that due to its controversial nature, the rulemaking will require 12-18 months prior to final promulgation of regulations. In no conceivable circumstance will the rulemaking be completed in time to govern the initial marketing activity that will precede the start of direct access on January 1, 1999. Accordingly, it is critical that the Commission establish a code of conduct to govern the activities of Duquesne and its affiliates/divisions during the pendency of a binding regulation,[86] in order to have a code in place for the initial customer selection and marketing process.

It is equally clear that the Code of Conduct proposed by Duquesne is not adequate, even on an interim basis. As will be explained below, Duquesne's proposed Code is extremely limited in scope and fails to cover crucial aspects of the EDC/affiliate or division relationship. Enron strongly advocates application of the Code of Conduct that was proposed by another EDC, Portland General Electric Company ("PGE") as part of its customer choice program filed last year. The PGE code of conduct is eminently fair both to suppliers and to the Company and, given that it was proposed by an electric distribution company, it can hardly be

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[86] Of course, the Commission recognized the necessity to implement competitive safeguards immediately by establishing an interim code of conduct applicable to PECO and its affiliates in the PECO Restructuring Order. As the Commission stated in reaching a determination to establish an interim Code of Conduct for immediate application to PECO:

> The rules adopted herein shall be applicable in PECO's distribution territory until changed. In particular, we note that the Commission is in the process of adopting regulations covering competitive safeguards in Docket L-0097 and Customer Supplier Interaction at Docket No. M-00960890F0011.

Id. at 129.

claimed that it is biased in favor of suppliers.[87] The PGE standards are much more comprehensive than those proposed by Duquesne, however. In addition to remedying the shortcomings of Duquesne's Code of Conduct in the area of functional separation, the PGE Code ensures that services, products, and information are all provided and utilized on a comparable basis among all suppliers. Additionally, it prevents the incumbent EDC from promoting any affiliated supplier, either through direct promotions or representations, or by identifying the affiliate using the name, logo, or trademark of the EDC.

Alternatively, given the precedent established in the PECO Restructuring Order, and recognizing the need for a uniform statewide governing Code of Conduct, Enron would find it appropriate to follow the rules established by the Commission in the PECO Restructuring Order, with a clarification and one addition. As the Commission has recognized on numerous occasions, the content of competitive safeguards is a generic issue which must be determined on a statewide basis. Establishment of such a uniform Code of Conduct avoids the necessity of parsing each EDC's Code of Conduct in order to resolve the inevitable claims that certain acts are or are not prohibited by the Code in question. The PECO interim Code of Conduct is fully supported by the record in this proceeding and should be adopted pending codification of final regulations.

The PECO interim Code of Conduct reads as follows:

> The Company and its divisional and/or affiliated EGSs ("PECO Supplier") shall comply with the following Interim Code of Conduct:

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87 This fact alone refutes Duquesne witness Hoffman's contention that Enron's comments on Duquesne's Code of Conduct stem from its interest in "handicapping" Duquesne and its affiliates. Duq. St. 6-R at 28.

1. The Company, in its role as the Electric Distribution Company ("PECO EDC"), shall not give a PECO Supplier preference over a non-affiliate in the provision of goods and services, such as processing requests for information, complaint processing and responses to service interruptions. PECO EDC shall provide comparable treatment without regard to the customer's chosen supplier.

2. PECO EDC shall supply services and apply the rules and other provisions of its Tariffs to non-affiliates in the same manner it applies them to a PECO Supplier.

3. PECO EDC shall not sell non-power goods or services to a PECO supplier at a price below the cost or market price, whichever is higher, for said goods or services. PECO EDC will not purchase non-power goods or services from a PECO Supplier at a price above the market price for said goods or services. No transaction between PECO EDC and a PECO Supplier shall involve an anti-competitive cross-subsidy, and all such transactions shall apply with applicable law.

4. PECO EDC shall simultaneously make available to all EGSs any market information, not in the public domain, that it provides to a PECO Supplier.

5. Employees of PECO EDC who have responsibility for operating the distribution system, such as receiving requests for power, purchasing power, scheduling delivery, or billing and metering, shall not be shared with a PECO Supplier, and their offices shall be physically separated from the office(s) used by those working for the PECO Supplier. Such employees of PECO EDC may transfer to a PECO Supplier provided such transfer is not used as a means to circumvent this Interim Code of Conduct. Any PECO Supplier shall have its own direct line management. Any shared facilities shall be fully and transparently allocated between the PECO EDC function and the PECO Supplier function. PECO EDC accounts and records shall be maintained such that the costs a PECO Supplier incurs may be clearly identified.

6. PECO EDC shall not condition the provision of any PaPUC jurisdictional regulated services on the purchase of power from a PECO Supplier.

7. Neither PECO EDC nor a PECO Supplier may directly or by implication falsely and unfairly represent:

   - that the PaPUC jurisdictional regulated services provided by PECO EDC are of a superior quality when power is purchased from a PECO Supplier; or

- that the merchant services (for power) are being provided by PECO EDC rather than a PECO Supplier;

- that the power purchased from an EGS that is not a PECO Supplier may not be reliably delivered;

- that power must be purchased from a PECO Supplier to receive PECO EDC PaPUC jurisdictional regulated services.

7b. PECO EDC shall not jointly market or jointly package its PaPUC jurisdictional regulated services with the services of PECO's Suppliers unless it offers the same promotion of services to non-affiliated Suppliers.

8. PECO EDC shall establish and file with the Commission a dispute resolution procedure to address complaints alleging violations of these rules.

Enron acknowledges that the Commission's February 5, 1998 Compliance Filing Order did not include the underlined portion of Rule 7 above. However, the PECO Compliance Filing Order did reaffirm that Rule 7 must be interpreted to preclude the EDC from promoting "its competitive affiliate any differently than non-affiliated suppliers."[88] Of course, such an interpretation precludes any joint marketing or joint packaging of services between the EDC and its affiliated suppliers unless the same opportunity is provided to non-affiliated suppliers. While Enron accepts and strongly supports the Commission's declaration of its intended interpretation of Rule 7, it appears preferable to clarify the rule through the additional proposed language to avoid future disagreement.

Second, the PECO interim rule does not include a prohibition against the use of the name of the EDC — a crucial protection against anti-competitive activity.

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88 PECO Compliance Filing Order at 45-46.

While Enron endorses use of the language in the PECO Code of Conduct as outlined above, if the Commission chooses to work from the language of Duquesne's proposed code, it must first make a number of revisions to bring it up to the level of PECO's original proposal, even prior to being able to impose the modifications subsequently made by the Commission in the PECO restructuring. Summarily, the required changes just to make the Duquesne code compliant with PECO's initial position are as follows:

1) Duquesne's proposed code contains no prohibition on preferential treatment between affiliated and non-affiliated suppliers. PECO Rule 1.[89]

2) Duquesne's proposed code does not require all tariffed services to be offered in the same manner to affiliates and non-affiliates, but only prohibits "undue discrimination." PECO Rule 2.

3) Duquesne's proposed code does not include any prohibition on anti-competitive pricing. PECO Rule 3.

4) Duquesne's code does not require it to make confidential market information available simultaneously to all suppliers but merely to make such information available to non-affiliated suppliers "upon request."[90] PECO Rule 4.

5) Duquesne's proposed code does not require physical separation of employees, and does not require segregated accounts and records or allocation of shared facilities. PECO Rule 5.

6) Duquesne's proposed code contains no provision which prohibits the tying of regulated and unregulated services. PECO Rule 6.

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89 All comparisons with PECO's proposed code of conduct refer to PECO St. No. 15, Exhibit GAC-2, which is the PECO proposed code which the Commission modified and clarified. See PECO Restructuring Order at 129.

90 Of course, non-affiliated suppliers will have no way of knowing what confidential information has been made available to affiliates in order to request such information from Duquesne.

7) Duquesne's proposed code contains no provision which limits the use of the EDC brand name. PECO Rule 7.

In addressing the further modifications and clarifications required by the Commission, first the Commission further mandated that affiliate or divisional transactions "for all goods and services, including power, must not involve any anti-competitive cross-subsidy."[91] Second, the Commission barred an EDC from making available any goods and services to its supplier affiliate unless those goods and services are also made available to other suppliers on comparable terms and conditions. Such provisions appropriately preclude EDC promotion of its competitive business affiliate's efforts. Duquesne's proposed code does not include such a prohibition on cross-subsidization.

Third, all EDC functions were required to be separately staffed from all competitive supplier functions, including management responsibility, and all employee transfers are made subject to functional separation requirements.[92] While Duquesne has included rules on "Separation of Functions" and "Officers and Directors" in its proposed code, the provisions are not broad enough to comply with the Commission's standard in that they do not contain appropriate restrictions on employee transfers, and do not apply at all to the individuals having management responsibility over such employees.

Fourth, the Commission additionally required that comparable treatment be provided to both affiliated and non-affiliated suppliers and supplier customers for all customer goods and services.[93] The nondiscrimination provision in Duquesne's proposed code of conduct

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91 PECO Restructuring Order at 130 (emphasis supplied).

92 Id. at 130.

93 Id. at 131.

only prohibits "preferential treatment" of affiliated suppliers and "undue discrimination" against customers. This provision should be modified to clarify that, if necessary, positive efforts must be made in order to provide comparable treatment. Overall, the Commission established the general standard that the EDC must "treat all competitive suppliers in a comparable non-discriminatory manner with similar terms, conditions and access to information, goods and services." [94] This Commission mandate provides for equal access, both in terms of timing and method of disseminating information, for all information, not just certain types of information as Duquesne has proposed.

Fifth, the Commission went beyond the PECO proposal and prohibited the tying of the EDC service with any other goods or services both as a condition of the provision of service and as a condition on the availability of certain terms and conditions.[95] Duquesne's Code of Conduct is silent on this subject, and should be modified appropriately.

Sixth, the Commission required a provision which bars the EDC from using its name or any other method to imply, directly or indirectly, that EDC service will be superior if an affiliate is subscribed to, that the reliability of service is inferior if a non-affiliate is subscribed to or that generation services are in fact being provided by the EDC. Duquesne has no comparable provision in its proposed code, which must be modified to achieve compliance.

Finally, the Commission barred EDCs from promoting their competitive affiliate any differently than non-affiliated suppliers. Again, Duquesne's code does not address this, and must be modified accordingly.

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94 Id.

95 Id.

Clearly, to the extent the Commission considers adopting Duquesne's own proposed code as the interim code of conduct to be applied to Duquesne, far reaching modifications are necessary to achieve compliance with the standards set forth in the PECO Restructuring Order. The most efficient course for the Commission would be to order the implementation of the code it ordered be implemented in the PECO proceeding (with the clarification and addition discussed above). In that manner, the Commission can be assured that the same rules are applicable to similarly situated jurisdictional utilities.

## B. Pro Forma Tariffs

### 1. Supplier Tariff

Enron has presented a Pro Forma Electric Generation Supplier Tariff which is intended to define suppliers' jurisdiction and responsibilities in relation to meeting customers' loads and all necessary involvement with the EDC.[96] This tariff should be adopted by the Commission for all Pennsylvania utilities. Such a measure will appropriately protect reliability.

Finally, and perhaps most importantly, the pro forma supplier tariff will establish a clear and enforceable set of rules and procedures to govern the multi-faceted relationship between Duquesne and suppliers seeking to deliver power to customers using Duquesne's distribution system. The Commission, just last week endorsed the need for a supplier tariff in its Compliance Order in the PECO restructuring proceeding.[97] The Commission's Order succinctly stated the required filing:

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96 Enron St. 5, Exh. 5, LRC-2.

97 PECO Compliance Filing Order at 38.

> We [previously had] required the filing of a Supplier Services Tariff as a means to establish the basic requirements for EGS/EDS interactions in a standard format through a standardized consistent process. This would provide specific useful information to all current and future market participants concerning protocols and other requirements.
>
> PECO is directed to file an appropriate Supplier Services Tariff which delineates supplier obligations, provides definitions of terms, fully discloses the Company's EGS "Policies and Procedures" and specifies its procedures for customer sign-ups, switching, balancing, billing and data exchange. The tariff should be consistent with applicable PJM and FERC requirements and Commission Orders.[98]

Duquesne's response to the Enron call for the filing of a Supplier Services Tariff — now a PUC requirement — was to claim that such a tariff was "unnecessary" because many of the provisions are covered and controlled by Duquesne's FERC approved Open Access Tariff.[99] But Duquesne's position is clearly overstated. While general topics suggested in the Enron Supplier Tariff may be contained in FERC-filed tariffs, many others having to do specifically with retail distribution service, are not. In any event, suppliers would benefit by a comprehensive listing of functions, services, and procedures, to the extent that Duquesne's FERC tariff does not provide such rules and services. Moreover, the Commission has made clear that the Supplier Tariff should contain provisions on "customer switching," "billing" and "data exchange"— issues that are not included in Duquesne's FERC tariff.

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98 Id.

99 Duq. St. 7-R at 1-2.

In this regard, Enron witness Coles detailed several specific issues and services which, if they are not covered by FERC-jurisdictional tariffs, must be included in a reasonable manner in Duquesne's PUT-approved Supplier Tariff. These issues include:

- Supplier obligation, energy balancing and load reconciliation.

To ensure reliable electric service to ultimate end-users there must be a clear, detailed understanding among all suppliers as to their obligations and balancing and reconciliation methods. This relationship must be detailed in advance of the implementation of retail access to enable suppliers to know how the system will work, to ensure a level playing field in retail access and to ensure that a particular competitive player is not given a market advantage. Enron's Pro Forma Supplier Tariff presents specific procedures for determining each supplier's load obligations.

- Energy Imbalance Service

Enron's Pro Forma Supplier Tariff provides a mechanism to handle energy imbalance service. Suppliers need a system to be in place which will determine a load aggregator's hourly responsibility for supply delivery to meet the needs of customers and a means of balancing supplies and actual loads. FERC has explicitly provided for energy imbalance services for wholesale and state-authorized retail transactions as part of Open Access transmission tariffs. These arrangements provide the foundation for energy imbalance service to suppliers and customers under Pennsylvania's retail access[100] and should be utilized as much as possible. For situations not covered by the FERC tariff such as customers with monthly metering, a load-estimating method and settlement mechanism implemented in conjunction with

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[100] Enron St. 5.0 at 10-12.

the EDC should be used, similar to that proposed by Enron, whereby the EDC would use actual monthly metered loads to calculate and prorate the estimated difference between delivered amounts and estimated actual loads in terms of on-peak and off-peak energy. Each supplier could seek to trade mismatches with other suppliers.[101] These procedures are included in Enron's proposed Supplier Tariff and should be adopted as presented there.[102]

- Supply Planning and Planning Reserves

Enron witness Coles has set forth a series of important factors that should be considered by the Company and the Commission in the process of conducting supply planning and accounting for planning reserves.[103] The Commission should direct that Duquesne include consideration of these factors and goals in all future planning.

**2. Conclusion**

The Commission should direct that Duquesne file a supplier tariff consistent with that proposed by Enron witness Coles, the PECO Compliance Filing Order , and Duquesne's FERC tariff and any applicable ECAR requirements, and to incorporate witness Coles' recommendations with respect to supply planning and planning reserve in its future decisions.

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101 Id. at 11.

102 Enron St. 5, Exh. 5, LRC-2, Rule 4.2.

103 Enron St. 5.0 at 15-21.

## IX. DUTY TO SERVE

### A. Service to Returning Customers

During the early years of direct access, service to returning customers[104] must be offered by Duquesne as an EDC under regulated, tariffed rates. This was the holding in the recent PECO restructuring proceeding.[105] In its Order on Reconsideration in that case the Commission stated:[106]

> PECO, as an EDC, remains a regulated utility and may only offer Commission-approved, tariffed rates . . . . Protected by the statutory rate caps, customers who do not shop remain regulated rate customers of PECO on the same terms and conditions of services unless changed by the Commission Order . . . . [T]he "shopping" credit is not relevant to a customer who does not shop. Customers who do not shop pay the approved tariff rate divided into unbundled generation, transmission, and distribution charges.

This status will exist until the Commission promulgates regulations under § 2807(e)(2) at the end of the transition period. After transition, the rules under which service to returning customers must be provided will be governed by 66 Pa. C.S. § 2807(e)(3), which states:

> If a customer contracts for electric energy and it is not delivered or if a customer does not choose an alternative electric generation supplier, the electric distribution company or commission-approved alternative supplier shall acquire electric energy at prevailing market prices to serve that customer and shall recover fully all reasonable costs.

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104 Returning customers are eligible for direct access and choose a competitive supplier and then, for any reason, return to the EDC for electric supply.

105 PECO Restructuring Order at 133-34.

106 PECO Reconsideration Order at 21.

While the Commission has stated it will consider and implement 66 Pa. C.S. § 2807(e)(3) by regulations at a later date,[107] and through Duquesne's view on this provision is not clear, Enron believes it is important to consider that issue now as the Commission plans for the future. Consistent with the effect of its holding in the PECO restructuring with respect to the transition period, it is imperative that the Commission apply § 2807(e)(3) in a manner that will not thwart electric competition after the phase-in period is over.

Although the Act does not define the phrases "prevailing market prices" and rates that "recover fully all reasonable costs" under § 2807(e)(3), that rate should be interpreted to be the same as the generation credit determined by the Commission. Conversely, generation credits should be designed to represent reasonable approximations of the projected delivered market prices for energy, including an allowance for retail costs, and are thus surrogates for the market price "plus" standard. Accordingly, they should be rates which reflect the same as "prevailing market prices" which "recover fully all reasonable costs." Establishing the generation credit as both the "cap" and the "floor" price payable by returning customers after transition will promote competition by providing an incentive to such customers to leave default service if the actual market price falls below the applicable generation credit by choosing competitive suppliers that offer lower prices. It will also provide customers with the benefit of significant rate reductions prior to the time that they may choose an alternative supplier.[108]

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107 PECO Restructuring Order at 134.

108 Contrary to some arguments, establishing the rate applicable to default customers as the residual generation credit does not mean that these rates cannot decrease. If Duquesne wishes it can file a Public Utility Code Chapter 13 tariff filing to reduce its rates to reflect reductions in its costs of providing default service. In the alternative, the Commission could order that the "default" rate be established annually after review and approval by

## C. Electric Transmission and Distribution Service

### 1. Unbundling Other Customer Services

#### (a) Introduction

##### (i) Competition in and Unbundling of Non-Wire Services

The provision of non-wire services[109] has nothing to do with the actual distribution of power and energy and is not part of a natural monopoly.[110] Accordingly, Enron submits that each of the non-wire services in Duquesne's service territory should be provided competitively in accordance with appropriate standards and protections to assure safety, reliability and consumer protection.[111]

In addition, Duquesne's costs and prices for these services must be unbundled from Duquesne's charges for distribution-related services.[112] Permitting non-wire services to be

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the Commission, and be set at the determined generation market price, plus all delivery and generation related A&G and retail sales costs. This would assure that the EDC, would not be able to "flex down" in an anti-competitive manner and would allow EGSs to determine, for a period that allows proper planning, the generation cap and "prevailing market price" levels they need to "beat" in order to provide savings to consumers.

109 The term "non-wire services" specifically identifies the functions of providing a meter; obtaining meter and usage data and distributing the information to consumers, utilities and any other appropriate energy service providers; billing consumers for energy service costs; and providing related information/communication services to consumers in connection with their energy service. They are distinct from the provision of "wire" services (i.e. the transmission and distribution of electricity). They are sometimes referred to as "revenue cycle services." Enron St. 3.0 at 2-3.

110 Enron St. 2.0 at 27.

111 Enron St. 3.0 at 2. Enron provided extensive testimony on this issue. See, Enron St. 3.0 and 3.1 (Enron witness Brown) generally, together with Enron St. 2.0 at 20-22, 26-28 (Enron witness Reising) and Enron St. 4.0 at 2-6 and 4.1 at 2-4 (Enron witness Muench).

112 The Act specifically provides that "the Commission may require the unbundling of other services." 66 Pa.C.S. §2804(3).

provided competitively but allowing their costs to be bundled with Duquesne's distribution service, would require the customer to pay twice and actually limit access to the competitive market for new entrants.[113] This is obviously unfair and is inconsistent with a level competitive playing field.

Duquesne should be ordered to undertake these steps, as interim measures, subject to the promulgation of final rules on the subject. Duquesne, however, opposes unbundling, claiming that it does not believe there is much savings to be offered to the customer through unbundling.[114] However, the study performed and introduced by Enron witness Reising showed that over 15% of Duquesne's "distribution" costs are actually related to billing and metering,[115] and that based on Duquesne's unbundled costs as of 12/31/96, revenue cycle (non-wire) services were over $31,000,000.[116] Neither the percentage nor the amount it reflects is insignificant.[117] In his study, Mr. Reising actually unbundled the non-wire services of meter/meter reading and billing from Duquesne's distribution rate and calculated the specific

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113 Enron St. 3.0 at 9. For example, EDCs could retrofit existing meters with their chosen version of new technology, while a competitor would be forced to construct a new automated meter reading gateway downstream of the EDC's meter. This would require entry to the customer's home, perhaps modification or removal of portions of a wall or the movement of the circuit breaker box. This construction would result in increasing costs as well as delays, and aesthetic concerns for consumers. Enron St. 3.0 at 9-10.

114 Duq. St. 8 at 18.

115 Enron Exh. 2, PDR-5, p. 1, line 41.

116 Enron Exh. 2, PDR-10.

117 Moreover, regardless of the amount of savings, unbundling will still create a competitive market, likely resulting in enhanced savings in the future. Enron St. 3.0 at 21.

amounts which are appropriately assessed for each of the components.[118] More specifically, Mr. Reising's analysis justifies the establishment of a revenue cycle service credit of $3.27 per month for secondary non-demand billing customers.[119]

Mr. Reising also showed that the costs or "credit" allocated to the unbundled service must be the fully embedded cost of providing that service.[120] Duquesne, however, asserts that when and if unbundling takes place it will give customers who choose alternative suppliers a credit based only on "avoidable" costs.[121] By proposing to limit the customer credit to incremental costs, Duquesne, in effect, is asking both competitors and ratepayers to subsidize its costs and to pay twice.[122] This position should be rejected.

Finally, there is good reason to unbundle non-wire services from distribution services at this time even if they are not immediately made competitive — so that the customer will know what the charges are for such services.[123]

**(ii) Open System Architecture**

In order to facilitate competition and unbundling, an open system architecture will also be required. As explained by Enron witness Brown, this means that all metering devices must be able to be interconnected with Duquesne's system so that they can be integrated

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118 See, Enron Exh. 2, PDR-7.

119 Enron St. 2.1, Exh. 2.1, PDR-10, p. 3.

120 Enron St. 2.0 at 21-22, 27.

121 Duq. St. 8-R at 7-8.

122 Enron St. 3.1 at 4.

123 Enron St. 2.0 at 21; Enron St. 4.0 at 3-4.

with a communications link to provide data readable to Duquesne and to any other affected supplier.[124]

Mr. Brown also encouraged the efficient exchange of usage and billing information between necessary parties by an information open access ("IOA") system.[125] IOA will operate in a manner similar to the electronic interfaces presently being implemented in the telecommunications industry [126] by allowing both the EDC and the EGS access to the necessary information to provide comprehensive, high quality service to customers.[127]

It is not clear whether Duquesne will utilize open system architecture. Duquesne has entered into a fifteen year "full-service" contract with Itron, Inc. to provide an electronic communication link to its customers.[128] This is known as the Customer Advanced Reliability System" ("CARS") and is discussed more fully below. Duquesne's Itron system is described by Enron witness Brown as a one-way interface subject to the complete control of Duquesne.[129] Mr.

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124 Enron St. 3.0 at 11. Such systems allow "the hardware, software and data of multiple parties to interconnect and communicate with each other seamlessly, thereby permitting the marketplace to operate with minimal switching barriers, and at the same time providing complete protection for proprietary customer data." Enron St. 3.0 at 2.

125 Enron St. 3.0 at 15.

126 Enron St. 3.0 at 15. The Commission is familiar with the concepts underlying IOA from the electronic interfaces between incumbent local exchange carriers and competitive local exchange carriers — Operation Support Systems — which have been required under the Telecommunications Act of 1996. Id.

127 Enron Exh. 3, JAB-5.

128 Duq. St. 8 at 5-6.

129 Enron St. 3.0 at 13. "Under such a system, Duquesne would control the content and format of information its competitors receive and would establish itself as communications 'gatekeeper' for its competitors. This type of system would not be the type of open network architecture system necessary to enable full competitive

Brown contrasted this proposed Duquesne system with Enron's two-way IOA system, which permits both EDCs and EGSs equal access to request customer information while preserving the customer's proprietary concerns. Regardless of the existence of CARS, the Commission should require Duquesne to provide the necessary open system architecture that will make it possible for all EGSs to obtain easily the data and information they need to serve their customers.

**(iii) Reasons for Immediate Unbundling**

Contrary to the arguments offered by Duquesne, Enron has convincingly demonstrated through its testimony that numerous reasons in the record support the immediate unbundling and competitive provision of non-wire services:

(1) Reduced Costs. Competition in non-wire services will lower the costs of these services to consumers, eliminate cost duplications and stimulate innovative responses to customer specific requirements. Based on past experience with deregulated markets, Mr. Brown showed that the unbundled market for billing and customer account services will likely exhibit major cost reductions and value added enhancements by third party providers that focus upon one, or a few, services.[130] Mr. Brown further showed that competition will also reduce metering costs.[131] Such reductions would, in turn, foster the growth of the pertinent technology and would

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development." Enron St. 3.0 at 14.

130 Enron St. 3.0 at 10-11. This occurred in the telecommunications industry where local exchange carriers reduced their own billing and customer costs by 28%. See Enron Exh. 3, JAB-1. However, these same companies realized that utilizing third party billing companies, who could concentrate on the specifics of the billing function, could produce even larger savings, between 20% and 62% below their initial expense levels. See Enron Exh. 3, JAB-2.

131 Enron St. 3.0 at 16-17.

likely result in the introduction of new pricing options by EGSs that would enable consumers to lower their bills for usage.[132]

(2) Expanded Choice. The introduction of innovative metering and metering services will bring expanded choice for Pennsylvania consumers.[133] This is one of the primary purposes of the Act. Advanced metering technology at a competitive cost is already available.[134] The use of these meters will allow EGSs to offer pricing options to cost-sensitive consumers to manage their demand for electricity to times of the day or the year when electricity prices are at their lowest and enable them to reduce their electric bills. New services could also be provided as part of the non-wire services.[135]

(3) Improve Success of Restructuring. Unbundling the cost of providing all non-wire services is crucial to the success of retail restructuring. Because these types of services represent a large proportion of small consumers' monthly bills, competitive suppliers may be unable to market effectively to these small customers unless unbundling and competitive provisioning is permitted.[136]

(4) Added Value. Competition in non-wire services will bring customers substantial benefits that would not be obtainable if competition is limited to the supply of

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132 Id.

133 Enron St. 3.0 at 11, 17.

134 Enron St. 3.0 at 17.

135 Mr. Brown testified these would include appliance monitoring, latchkey services, toxic gas detection, time-of-use pricing, and outage detection. Enron St. 3.0 at 11; see, Enron Exh. 3, JAB-3.

136 Enron St. 4.0 at 6.

generation, because only then will they be able to offer services and products in addition to "commodity" price competition. Conversely, absent the ability to offer such services competitively, they will be placed at a competitive disadvantage vis-a-vis Duquesne's monopoly, and will be unable to provide added value to consumers.[137]

(5) The California Experience.[138] Enron believes that experience in California supports the immediate unbundling of non-wire services in Pennsylvania. In 1991, when the California Public Utility Commission unbundled natural gas transportation and procurement, it limited unbundling and competition for smaller customers to only the commodity itself. As a result, the incumbent gas utilities were able to reduce their cost of gas to meet the competition for gas prices. Competitors did not have the ability to create additional value for customers by providing better or less expensive service in other areas, such as metering and billing. Consequently, the number of competitive marketers has severely declined.[139] The California Commission has recognized this problem, and is attempting to rectify it.[140]

Significantly, the California Commission avoided the same mistake in restructuring the electric industry. In its Opinion on the Unbundling of Revenue Cycle Services,[141] the California Commission allowed non-wire services to be provided competitively

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137 Enron St. 3.0 at 3.

138 Enron St. 3.0 at 4-6.

139 While nearly fifty marketers entered the California market, only three remained at the end of 1996. The net result has been fewer competitors and less value for these smaller customers. Enron St. 3.0 at 4.

140 Enron St. 3.0 at 4-5.

141 Enron St. 3 at 5-6, citing Decision 97-05-039 (May 6, 1997) at 8. The California Commission there stated with respect to the unbundling of non-wire services:

as of January 1, 1998, except for smaller customers (20 kW or less) which it deferred until January 1, 1999.[142]

The California Commission's decision to allow the competitive provisioning of non-wire services has already produced dividends. For example, Cellnet Data Systems recently announced that it is constructing a metering communications network in California to bring new products and services to customers at lower costs. Absent the action of the California Commission to unbundle and allow competition in non-wire services, Cellnet would not have been able to make those competitive new services available to customers.[143]

This Commission should avoid the primary and evident mistake made by the California Commission in the deregulation of gas — the failure to fully unbundle non-wire services — and take advantage of its experience in unbundling those services in the deregulation of electricity.

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> There are long-run issues that might motivate this Commission to consider the merits of allowing energy suppliers to offer these services some time in the future. What prompts us to ask these questions now is a concern that direct access opportunities to residential and small commercial customers in 1998 might be severely limited if we fail to allow energy providers to provide these services and to offer their customers the resulting savings.

142 Decision 97-05-039 at 16-17.

143 Enron St. 3.0 at 6. As Enron witness Brown observed, Duquesne witness Allison (Duq. St. 8 at 16-17, Exh. FRA-4) refers to an article written by the vice president of Cellnet, Chris S. King. Mr. Brown observed that Cellnet — and Itron, the supplier of CARS — have often testified to their technologies' dependence upon economies of scale. However, Cellnet is now entering the competitive market even without economies of scale since, it has no assurance of a large customer base for its service, Cellnet has made a large investment in California's unbundled and are competitive market. Enron St. 3.0 at 6, n. 3.

(6) The Duquesne "Itron" meter reading system demonstrates the potential benefits from competitive non-wire services. Ironically, the testimony of Duquesne's own witness, Mr. Allison, demonstrates the potential values that could be obtained from an environment that encouraged the installation and use of advanced meters and remote meter reading. CARS is an advanced meter and meter reading system which permits cost savings from remote meter reading and other efficiencies, the offering of all sorts of advanced services such as customized billing, real time and "on demand" readings and better service.[144]

Mr. Allison testified that, over a 15 year period, Duquesne anticipated it would save $58 million just from the ability to utilize remote meter reading.[145] This does not include savings from other efficiencies such as quicker billing and processing of payment receipts. The CARS system is also expected to allow the non-utility installer and operator, Itron,[146] to offer a host of revenue producing services such as "energy management,"[147] power outage notification and "defined cycle billing."[148] The provision of these type of services is projected to produce over $25 million in revenues over the 15 year planning period, a portion of which ($1 million) will accrue to Duquesne.[149] None of these cost savings or additional revenues are included as

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144 Duq. St. 8 at 9.

145 Tr. 863-64; Duq. Exh. FRA-7 at 48-50.

146 Tr. 859-60.

147 Duq. St. 8-R at 14.

148 Duq. Exh. FRA-7 at 43.

149 Tr. 870-71; Exh. FRA-7 at 44.

offsets to Duquesne's claimed distribution rates.[150] Mr. Allison's testimony illustrates both the potential advantages to customers if competitive metering were permitted and why EDCs — like Duquesne — are so opposed to allowing any other entity to provide such services. The utility wants to keep these savings and revenues to itself even though it has no right to such exclusive provision (a meter is obviously not a monopoly service any more than generation is and EDCs never received exclusive franchises for "metering"), and even though its position will obviously slow the deployment of such meters and deny customers their benefits (for Duquesne that means the prospect of even more advanced meters and services in response to competitive pressures — if such were allowed), for years to come. It also refutes the contention by some that only a utility could be trusted to install, operate and maintain meters.

**(b) Resolution in Generic Proceedings v. Resolution in this Case**

Duquesne argues that the unbundling of non-wire services should not be considered in this restructuring case, but should be addressed as part of the collaborative generic rulemaking process in progress.[151] Duquesne gives no good reason for its position, which is not consistent with the Act's objectives. Duquesne essentially seeks simply to delay the advent of unbundling in order to enhance its own competitive position.

Duquesne's proffered reasons for delay are that (1) issues still need to be resolved so as not to compromise reliability; and (2) establishing a generation market should be the first priority and many details still have to be worked out in that regard.

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150 Tr. 864-65.

151 Duq. St. 8-R at 19.

With respect to the first reason, the ongoing collaborative process Duquesne refers to actually supports immediate unbundling because it shows there is already a process in place to resolve the fine details of unbundling.

As to its second contention, the unbundling of non-wire services will not interfere with establishing a competitive generation market; it will enhance it. Duquesne again simply attempts to create barriers to competition by equating choice with confusion. This is nonsense. There is no reason why consumers cannot choose non-wire services in conjunction with direct access; competition can and should be implemented and advanced in all possible areas. So long as there is an adequate statewide consumer education program, consumers will understand their options and be able to make reasonable choices. California and Arizona have both resolved such details and are unbundling non-wire services. Other states, understanding and recognizing the benefits of competition, are also moving toward the unbundling of these services.[152] There is no reason for Pennsylvania to lag behind.[153] This Commission has already ruled that such unbundling and competitive entry are legally permissible.[154] In its "Customer Services Order,"

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152 Enron St. 3.1 at 3.

153 IBEW witness Moran also opposes unbundling. He contends that only the employees of an EDC have the ability to deal with safety requirements. Safety is a concern, but there is no reason that employees of an EGS, if properly trained and if they meet the requirements imposed by the Commission, would not be able to provide the same safe services. Indeed, Duquesne's present metering system is owned and operated by non-utility personnel. See, Tr. 859-60. The basic thrust of Mr. Moran's testimony is that meter and billing activities should remain a monopoly with the local utilities. (IBEW St. No. 1 at 8). This view is contrary to the pro-competitive purpose of the Act and taints all of his so-called concerns about safety and other factors in Enron's proposed distribution service tariff. He simply does not wish to accept competition in this area whether or not it is beneficial for the consumer or the union. His testimony should be rejected.

154 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

the Commission recognized the right to unbundle and competitively provide the billing and supplier complaint functions under the Competition Act. The Commission stated:[155]

> [We] simply disagree with the conclusions. . . that only EDCs can provide these customer service functions. We submit that there is nothing in the Act that would prohibit the supplier single bill option and supplier complaint handling. Although § 2807(C) recognizes that the EDC "may be" responsible for the billing of all electric services, there is nothing in this passive provision or anywhere else in the Act that makes the EDCs the exclusive providers of these customer service functions.
>
> We believe that the Act's reference to the EDC's responsibility to provide customer service functions under § 2807(D) is intended to maintain the status quo and is merely a reflection that the EDC must stand ready to provide these customer service functions. However, concerning the two specific customer service functions at issue; namely, billing and complaint resolution, we do not read this provision or any other provision of the Act as excluding suppliers from providing these functions. In fact, we believe this interpretation is consistent with the declared policy of the Act to create a competitive market for the generation of electricity.

This ruling is also directly applicable to the legality of furnishing competitive metering. While the Commission did not implement this guideline immediately, it retained it as an option to be explored in the context of the restructuring filing of each utility. Although the Commission has strongly indicated it will consider and likely implement such unbundling in the future, Enron submits that unbundling of non-wire services is vital now, at the beginning of direct access, when pure price pricing competition for generation services will be restricted by the imposition on all customers — regardless of their selection of an electric generation supplier

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Chapter 56 Pursuant to 66 Pa. C.S. § 2809(E) and (F), Docket No. M-00960890F.0011 (Order entered July 11, 1997) ("Customer Services Order").

155 Id. at 10-11; see also id. at 29.

— of CTCs/ITCs. Making metering and other non-wire services subject to competition immediately will bring all the above-described benefits of competition to Pennsylvania consumers and businesses, which will enhance the overall value of direct access. As Mr. Brown observed, requiring unbundling in this proceeding to allow competition in the non-wire service areas will allow efficient EGSs "to differentiate themselves from their competitors and attract customers to their products based on comprehensive and innovative service offerings, while at the same time offering real value and benefits to Pennsylvania's consumers."[156]

**(c) Interim Rules Applicable to Duquesne**

Regardless of its determination whether to allow the competitive furnishing of non-wire services at this time, the Commission should require the unbundling of those services in Duquesne's rates in any event, so that customers will know what they are paying for these various non-wire services.[157] Enron further urges the Commission to allow the competitive furnishing of non-wire services at this time on an interim basis and subject to final rulemaking. This is especially important in the case of Duquesne so that its CARS does not become so entrenched before unbundling of metering occurs that it becomes impossible to allow competitive provisioning.

**(d) Specific Services**

**(i) Customer Billing**

Billing and collection are competitive functions that an EGS should have the option of providing. Duquesne should be required to separate and unbundle its billing and

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156 Enron St. 3.0 at 4.

157 Enron St. 2 at 21, 27.

collection functions as part of its restructuring, as the Commission has held it has legal authority to require.[158] Otherwise, customers will be required to pay for the EDC's billing and collection activities even though they choose to receive billing services from their supplier as the Act permits.[159]

The Commission should further require Duquesne to implement and comply with full customer choice of billing services as part of its restructuring. This objective requires that customers be permitted to choose one of the following billing options:[160]

(1) Single EDC bill. Under this option, Duquesne would provide all billing services — for the services it provides and on behalf of the customer's supplier of choice — including billing for non-wire services and the generation portion of the bill;

(2) The Two Bill Option. Under this option, Duquesne would continue to bill for its distribution, transmission and competitive transition charges (i.e., CTC and ITC charges), while EGSs would provide a separate bill for all services the customer chooses to receive from the supplier (including generation services and other non-wire services to the extent the customer chooses to utilize the supplier for such services);

(3) The "Supplier Single Bill" or "Complete Bill" Option. EGSs would provide a single or complete bill in which the EGS would bill not only for the services that it is providing (i.e., generation and, if chosen by the customer, non-wire services) but also for services provided by Duquesne including transmission, distribution, CTC and ITC.

Of the three billing options, the supplier complete or single bill option is the option which allows suppliers to add the most value for customers. The supplier single bill

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158 Customer Services Order at 10-11. In the recent PECO restructuring case, the Commission declined to require the third billing option "on the record" before it. PECO Restructuring Order at 138. We submit the instant record shows the clear benefits and requires a different result.

159 66 Pa.C.S. § 2807(c).

160 Enron St. 4.0 at 7.

option would enable the provision of service functions such as advanced metering, demand management and all "TLC" customer services, plus a host of as yet unforeseen products and services to fulfill consumer desires. Furthermore, specialized or customized billing can provide or enable detailed information about electric use for customers who choose time-of-use pricing, information about the amount of energy certain appliances utilize, automatic notification to customers when electric use reaches a pre-specified level and many other products and enhancements which customers desire and in which they find value.[161]

Duquesne opposes the supplier bill option.[162] Its reasons are somewhat difficult to understand, but apparently center around its alleged experience in the Customer Choice Pilot Program.[163] None of its claims is valid, and they ignore the fact that the very purpose of the pilots is to shake out implementation problems.[164]

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161 Enron St. 4.0 at 8-9.

162 Duq. St. 8-R at 21

163 Duquesne makes a big point out of its contention that 6 of the 17 suppliers participating in the pilot require their customers to adopt the two-bill option (Duq. St. 8-R at 21-22). The fact that 6 of 17 suppliers require their customers to adopt the two-bill billing option does not contradict Enron's position, but actually supports it because it shows that billing choices should be permitted. For those customers who do not mind receiving two bills, it gives the EGS the opportunity to provide some other competitive service as a trade-off for receiving two bills. Moreover, if 6 of the 17 suppliers are requiring the two-bill billing option, that means that 11, or nearly twice as many, are not. Finally, it is interesting to note that Duquesne has provided no information about the 6 suppliers. Duquesne does not state whether they serve residential customers and what their success in the pilots has been. It does not state whether they have attempted to provide any counter-balancing incentives. One would need to know why they required this and whether it was for purposes of the pilot only or will still be a requirement when direct access begins. In any event, that is what competition is all about. Enron St. 4.1 at 4-6.

164 Duquesne further claims that the exchange of information with suppliers by electronic media during the pilot has been somewhat problematic. Id. That is the very reason why the General Assembly called for a pilot program — to work out implementation

Maybe most importantly, there is no potential downside to customers that could result from the fully competitive provisioning of billing services. No customer will be required to choose this option; the EGS will be forced to convince customers of the benefits that would result from allowing the EGS to provide non-wire services in addition to generation supply.[165] Furthermore, any customer who is dissatisfied with any aspect of the EGS's service, would have the right to return to the EDC or switch another EGS.[166]

The ability to obtain all services from competitive providers will maximize the customer's choices — and competition. The customer should have the right to obtain, and the EGS to provide or acquire as agent for the customer, all services, including delivery services. This will enable the EGS to maximize value in all areas; increase efficiencies; and insulate Duquesne from risk of consumer nonpayment by making the supplier responsible to remit to Duquesne for the service used by the consumer. Moreover, the important element of billing is the

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problems. Moreover, Enron witness Muench testified that it was his understanding that a substantial cause of these problems lies with Duquesne. For example, Duquesne was late in distributing its customer lists and its lists did not include customer account numbers. This made it difficult for suppliers to utilize those customer lists accurately and efficiently. Enron St. 4.1 at 6.

165 OCA witness Alexander also criticizes the supplier bill option because it would lead customers back to "bundled" services (OCA St. 5R at 6-9). This is not accurate. Since there will be competition, different suppliers will offer different services that will allow the customer to choose the type of billing he or she wishes. Even if some of those services are bundled, the situation is far different under competitive choice than the bundling that exists under the current regulated, monopoly "single bundle" environment.

166 The steps needed to implement the three billing services are set forth in Enron St. 4.0 at 10.

obligation to have collections and customer care in accordance with Chapter 56 provisions.[167] From Enron's perspective, this implies that the uncollectible expense must be unbundled from the distribution rates. The key is that with the bill go all of the collection responsibilities.

**(ii) Metering**

Not only should the choice of who bills the customer be decided by the customer; meters should also be provided competitively. Admittedly, meter installation and repair need to be conducted by properly trained personnel in accordance with appropriate standards. But there is no merit to Duquesne's contention that only employees who work for an EDC are capable of being so trained.[168] As noted, Duquesne's present metering system for residential customers has been "outsourced" to a non-utility company. EDC concerns can and should be addressed by having the Commission establish minimum qualifications and training for installation personnel and to require EGS services to meet the same service standards as the EDC.[169] There is no reason

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167 Enron St. 4.0 at 12-14.

168 Duq. St. 8 at 17-18; IBEW St. 1, Attachment (Testimony of William Schmitt at 2-5).

169 As Enron witness Brown testified, the introduction of competition will require that the Commission develop additional standards with respect to meter reading, including minimum data elements, timely data access, open architecture storage and communications, security and enforcement procedures. These new standards should not dictate the use of specific metering devices, communication protocols employed at the customer site, hardware, software, ownership of meters, or other terms of commercial service agreements. Finally, as the Commission institutes the unbundling of metering service, Enron would recommend that a working group format is an appropriate venue to develop the additional guidelines for interim implementation with permanent standards established in the rulemaking. Enron St. 3.0 at 14.

why EGS personnel cannot perform the meter and billing related services with at the same level of competence and safety as customers presently enjoy.[170]

In its Customer Services Order, the Commission reviewed the provision regarding meter reading under § 2807(d) of the Act and concluded that all "physical activity" relating to metering should be performed by the EDC.[171] This matter was further reviewed at the Commission's metering docket[172] where the Commission recently issued an order proposing regulations.[173] Both the Commission's Customer Services Order and Advanced Meter Order would appear to allow a competitive EGS to act as the customer's agent to order the EDC to purchase the meter and then read the meter, if it can be done remotely, i.e., non-physically, so long as the meter is physically installed by the EDC.[174] But the Commission's small step will do little to promote new and innovative meters and meter reading. The Commission's current proposal actually requires the customer or the supplier to buy an "approved" meter for the EDC.

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170 A similar argument was made — in the years before the break-up of AT&T — that only Bell System employees could do such work. Today, the vast selection available in the purchase of phone equipment, how much more convenient it is to have a phone installed and how phone equipment has improved through innovation is taken for granted.

171 Customer Services Order at 22-23, 26.

172 Rulemaking re Advanced Meter Deployment for Electricity Providers, Docket No. L-00970128 ("Advanced Meter Order").

173 Order entered November 24, 1997.

174 Customer Services Order at 22-23; Advanced Meter Order at 14-15, 17, 19; proposed regulations §§ 57.252(a), 57.253(b), 57.254(a), (b). The proposed regulations also recognize the ability and right of the EGS to read advanced meters, but propose to keep the physical aspects of metering, including the physical reading, with Duquesne. Since the supplier will have the ability to read the meter remotely, it appears that the only "physical" reading required is the two-year physical examination under Chapter 56 to make sure that a meter is working properly. 52 Pa. Code § 56.12(5)(ii).

This requirement basically denies the ability of suppliers to provide the enhanced meters and meter reading to their customers economically and completely prevents the use of "proprietary" or customized advanced meters that suppliers might themselves wish to provide. It also calls into question the ability of a supplier to offer enhanced and special services — in the same way that Duquesne itself provides (or plans to provide) with its CARs system.

Although the Commission stated in the Advanced Meter Order, as well as in the PECO Restructuring Order, that it will not require unbundling of metering services at this time, it has recognized and anticipates that it may be appropriate to do so in the future after market participants have obtained more experience.[175] At the same time, the Commission continued to recognize that the choice of generation supplier requires the opportunity for customers and suppliers to choose advanced metering equipment necessary to support the new generation services that will be available.[176] Enron urges the Commission, based on the record in this case, to take the next logical step and allow EGSs not only to select the type of advanced meter, but to provide it competitively. Following the Commission's ruling on the legality of unbundling billing and customer service functions, there is no rational or legal reason that would preclude the unbundling and competitive entry into metering and metering functions. The same rationale which allows the unbundling of billing will allow the unbundling of metering.[177]

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175 Advanced Meter Order at 12-13.

176 Id. at 14-15.

177 Duquesne claims that implementation of unbundling and competition for these services should await the installation of cheaper and more advanced meters. But this is another delay tactic which again provides the very reason not to delay unbundling. Duq. St. 8-R at 8. Duquesne is seeking to make such meter installations in a regulated environment where ratepayers will have to bear the cost of such meters and Duquesne's proposed CARS. In fact, Duquesne seeks, through its CARS proposal, to be rewarded for its

### (e) Conclusion

The Commission should order Duquesne to unbundle non-wire services immediately as part of its restructuring plan, and develop non-discriminatory terms, conditions, and protections so that EGSs can provide these services competitively. In addition, the Commission should announce a policy in favor of open architecture for non-wire functions so that new options for metering, billing and information services are not unnecessarily foreclosed and that these policies should apply to Duquesne's Itron leasing agreement. Finally, the Commission should continue its generic review of these issues and encourage workshops to discuss what standards and protocols need to be identified to increase customer access to unbundled non-wire services and to work out procedures for the sharing of meter data. Permanent rules should be reflected in the Commission's rulemaking. Only in this way will robust competition emerge.

## 2. Agency

It is undisputed in marketing circles, regardless of the commodity, that the vast majority of consumers, if given the choice, will seek and subscribe to a provider that can offer a comprehensive service package to the customer. In a competitive market, market pressures will require market participants to provide products and services which meet customers' needs.

Given that fact, in the competitive electric generation market, most customers will want their preferred provider to serve not only as their supplier of electricity, but also as their "single point of contact" with the utility. Since transmission and distribution services will

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inertia in not previously implementing such deployment and be able to enjoy the advantages of system in a non-competitive environment.

remain a monopoly under the Act, in order to ensure that consumers have complete freedom of choice, suppliers should be able to act as agent for the customer to procure distribution, transmission, generation, and revenue cycle services on behalf of their principal-customers, and send them a single bill for these services as well as to bill and collect the CTC/ITC and transfer such payments to the utility or its agent.[178]

Under any agency arrangement, suppliers would be able to accept orders for service from customers and, through contact with the EDC, initiate or continue service at the customer's location. Essentially, through the agency agreement, the supplier would become the customer of record and would be directly responsible for payment to Duquesne of the EDC's charges associated with distribution and transmission.[179] The reason that agency is a positive element of a competitive market for consumers is obvious: consumers want the efficiency and ease of being able to choose "one-stop shopping," and suppliers should be able to provide this service for their convenience.

Such an agency relationship is not new to the Commission or to Pennsylvania utilities. In the natural gas industry, consumers have this option available to them in those markets which have been subject to competition; in fact, industrial natural gas customers have been able to enter into an agency relationship with their utility to procure gas service for over ten

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178 Enron St. 4.0 at 13.

179 Naturally, consumers should also be able to seek transmission suppliers or other suppliers in any combination they select; having their supplier act as agent to procure these services is only one option among many, but it should be an option. Enron St. 4.1 at 8-9.

years.[180] The agency service provided one bill and one point of contact while still allowing the customer to receive competitive supply. For example, Columbia Gas introduced an "Experimental Special Agency Service Rate" in 1986.[181] This rate was extended each year until 1990, when it was made permanent by Commission Order.[182] Peoples' Gas, for example, today offers agency service to residential as well as to industrial and commercial customers and permits marketers to act as agents for their customers and procure transportation services on their behalf — precisely what Enron is advocating for electric service.[183] The fact that agency is now the rule in the natural gas market, rather than the exception, indicates that there is no legal or technical bar to implementing an agency concept for electric suppliers.[184]

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180 See, e.g., Pennsylvania Public Utility Commission v. Equitable Gas Company, R-00963858 et seq. (Dec. 4, 1997) at 59. Equitable successfully argued that through two rate cases, eight §1307(f) proceedings, and multiple investigations "the Commission has not ever found that [Equitable's] agency service . . . serves any purpose other than to allow Equitable to satisfy its customers by meeting competition and maximizing recovery of fixed costs." In that particular context, Enron opposed agency on the basis that the distribution company used its position as agent for the customer to unfairly support its affiliated supply company, and Enron would again oppose it in a similar situation. However, implementing agency by suppliers in the electric market would present customers with more choices, not fewer, as there would be more suppliers offering "one-stop shopping", among which consumers would be free to choose.

181 Petition of Columbia Gas for Permission to File Tariff Supplement on Less than Statutory Notice Period, Docket No. R-860351.

182 Docket No. R-891536 (Feb. 2, 1990).

183 Peoples' Tariff Gas Pa-PUC No. 42, at Rate GS-T.

184 It should be noted that Enron has raised concerns about the use of agency in the gas context because it has resulted in services being provided in an unfairly competitive manner. The reference to the existence of agency in gas is to show that it has been approved by the Commission and that there are no legal or operational impediments to its implementation.

The arguments which have been made against allowing this manifest benefit to consumers to take place in the electric industry have generally alleged concerns about reliability and quality of service.[185] But the preservation of reliability and service standards will be guaranteed by the Commission's Order in the Customer Services Order which supplies proposed guidelines for maintaining customer services at the same level of quality which is now enjoyed by consumers. In addition to mandating that standards remain constant, the Commission has indicated that policies will be developed to provide specific requirements that must be met when suppliers handle applications for new service.[186]

In short, the procurement of additional services by suppliers via an agency relationship with customers is a benefit which consumers desire and value, and it should be available to them. Notwithstanding claims to the contrary, allowing suppliers to perform this function can only operate to the benefit of the consuming public, by allowing them to take advantage of the convenience of obtaining all of their electric services through one source, and ensuring that there are a wide variety of providers of this valuable service to choose from.

### 3. Other Issues (e.g., CARs system)

#### (a) Duquesne's "CARS"

As noted above, Duquesne is proposing to introduce an advanced metering system, known as CARS, which Duquesne has engaged Itron to install. There are two issues associated with CARS.

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185 See, IBEW St. 1 at 3-8. Duquesne witness Mr. Allison (Duquesne St. 8-R at 22) claims that there are no benefits to the customer to be derived from agency.

186 Customer Services Order at 18; Appendix B.

First Duquesne claims it will provide retail suppliers equal access to the service offerings of the CARS system, but it is significant that in describing these services, Duquesne witness Allison speaks of Duquesne offering these services.[187] To the extent that Duquesne provides these services to suppliers they should be at cost and should be fully available to resell by the supplier.

Second, Duquesne must assure that its CARS system is fully open and capable of accommodating both the Commission's very limited metering proposed rule, as well as full competitive provision that the Commission has indicated it intends to implement in the future. The fact that Duquesne has signed a 15-year lease should not change the result. Once the Commission mandates competition in non-wire services, the Commission should order a revision in the lease, if necessary, that would guarantee that ratepayers did not lose the advantages of competitive metering. Finally, the Commission should direct Duquesne to work with suppliers and others to implement modifications in CARS to allow supplier-provided meters, automatic meter reading and billing through an IOA.

## D. Consumer Protection and Service Issues

### 1. Termination

Enabling electric suppliers to act as agents for customers, as described above in Section IX.C.2, will allow the supplier to act on behalf of the customer to request the cancellation of electric supply from one source, and to replace it by ordering electric service from another supplier. This does not mean, however, that suppliers can physically disconnect customers for non-payment. In fact, they cannot do so. Parties to this proceeding, most notably

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[187] Duquesne St. 8-R at 13.

OCA,[188] have expressed concern that suppliers could act in their capacity as agents to have the EDC physically disconnect customers. Enron neither claims that it can, nor desires to make this a supplier prerogative as part of the supplier's agency responsibility.

Suppliers can "cancel service" in that they can stop providing service to a non-paying customer by terminating the contract with that customer, after complying with all applicable Chapter 56 requirements, including the sending of appropriate written notices to the customer and to the EDC.[189] At that point, the customer will either attempt to repair the relationship with the supplier, or will default to the supplier of last resort.[190] However, that is the extent of the power of suppliers to stop service to a customer. Customers run no more risk of being disconnected from the EDC in a competitive environment than they do in the current regulated one. Suppliers will still negotiate with customers to set reasonable terms for payment if payment becomes a problem, and customers will still be assured of Chapter 56 protections prior to disconnection from the grid.

**2. Switching Fees**

To the extent that Duquesne is proposing any fee for switching suppliers such fees should be prohibited in accordance with the policy articulated in the PECO Restructuring Proceeding and Duquesne's failure to support the fee.[191]

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188 OCA St. 5-R at 6-9.

189 The Customer Services Order provides appropriate guidelines for suppliers to terminate service. For example, the Order specifies that written notices from suppliers must clearly inform the customer that failure to pay will result in the cancellation of the contract with the supplier, not in termination of service, id. at 39.

190 Id. at 38.

191 PECO Reconsideration Order at 17.

## E. Partial Payments

Duquesne appears to be intending to first apply all partial payments to extinguish its receivables — unless otherwise directed by the customer.[192] Enron's only request of the Commission in its determination of the distribution of partial payments received by the EDC is that payment application be fair and nondiscriminatory. The only reasonable way to assure equitable application of partial payments is to apply payments on a *pro rata* basis. As explained by Enron witness Muench, any other method would be:

> [C]learly unfair to Alternative Electric Suppliers. The Commission should require that payments received from customers by Duquesne, or other billing agent, be applied to the services provided by the entity that does not have direct access to the customer. There is no reason why Duquesne's charges should be given priority over a supplier's, unless Duquesne relinquishes billing responsibility.[193]

If payments are not applied on a *pro rata* basis, a disproportionate amount of delinquencies will be allocated to suppliers likely leading to early discontinuance of service by the supplier and, through return to the PLR, elimination of competitive benefits to those customers — customers who may most need the price reductions offered by the competitive environment. Furthermore, EDCs, including Duquesne, are already recovering all uncollectibles, including those uncollectibles associated with the generation portion of the bill, in current rates. Since, in a competitive environment, suppliers will assume the risk of generation

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192 Enron St. 4.0 at 17.

193 Id.

related uncollectibles, assigning a disproportionate amount of potential uncollectibles to suppliers will result in double recovery of uncollectible expense by Duquesne.[194]

Duquesne witness Allison has set forth a priority order for payment based upon the PUT's present view on the subject.[195] That method should be altered to "pro rata." Even if the PUT interim method is accepted, the priority order listing of "supply charges" as a priority item should not give Duquesne's supply charges a leg up over the supply charges of suppliers not affiliated with Duquesne.

## X. UNIVERSAL SERVICE AND ENERGY CONSERVATION

### A. Introduction

Duquesne's proposed restructuring plan includes a universal service proposal which, it asserts, meets the requirements of the Act. However, under its proposal, all universal service support towards payment of universal service customer bills would be retained by Duquesne and no portion would be allocated to suppliers serving customers eligible for universal service support.[196]

Enron strongly support initiatives to maintain universal service programs to provide support to low income, payment troubled Pennsylvanians; however, such programs should be designed on a competitively neutral basis as required by the Act. In order to achieve a competitively neutral universal service program, the support must be portable and should be

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194 Enron St. 4.0 at 18-19.

195 Duq. St. 8-R at 23-25.

196 Duq. St. 8 at 7-11.

allocated to each component of a low income customer's electric bill on a *pro rata* basis in proportion to the average comparative level of charges on customer bills.[197]

The Commission apparently agrees. PECO's proposed restructuring plan included portable support within its universal service plan proposal. In its PECO Restructuring Order, the Commission approved PECO's proposed universal service program without modification on this point.[198]

## XI. CONSUMER EDUCATION

### A. Scope of Consumer Education

#### 1. State-Wide vs. Company Specific

Consistent with the testimony of Enron witness Muench, consumer education should be conducted on a state-wide basis by the PUT with funding from customers through non-bypassable charges.[199] Any other system will risk Duquesne using customer-supplied funds to promote its own brand and market presence to the exclusion of suppliers.[200]

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197 Enron St. 5.0 at 32-33.

198 In fact, this is one of the few components of PECO's proposed restructuring plan which the Commission approved.

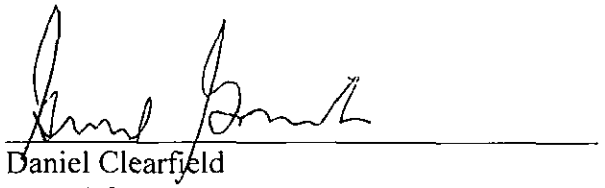
199 Enron St. 4.0 at 26-32.

200 Id. Mr. Hoffman's call for suppliers to contribute to a state wide fund (Duq. St. 6-R at 26-27) conveniently ignores the fact that EDCs don't actually contribute — customers do.

## XIII. CONCLUSION

For all of the foregoing reasons, Enron Power Marketing, Inc. respectfully requests the Honorable Commission to implement the recommendations as set forth in this brief.

Respectfully submitted,



Daniel Clearfield
Gerald Gornish
Robert Longwell
Wolf, Block, Schorr and Solis-Cohen LLP
212 Locust Street, Suite 300
Harrisburg, PA 17101

Dated: February 10, 1998

# APPENDIX "A"

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

DUQUESNE LIGHT COMPANY

Application for Approval of a Restructuring Plan
Pursuant to 66 Pa. C.S. § 2806(d)
Docket No. R-00974104

ENRON POWER MARKETING, INC.
INDEX OF TESTIMONY AND EXHIBITS

| Exhibit | Description | Date Identified | Date Admitted |
|---|---|---|---|
| Enron Cross Examination Exhibit No. 1 | CFR Uniform System of Accounts: Accounts 908 and 909. | 12/17/97 | 12/17/97 |
| **Enron Statement No. 1** | **Direct Testimony of James D. Steffes** General overview of competitive services; the Portland General Code of Conduct. | | |
| Exhibit 1 JDS-1 | Market share of utilities/affiliates in Retail Access Programs. | | |
| Exhibit 1 JDS-2 | Portland General Electric Company Tariff Code of Conduct. | | |
| Exhibit 1 JDS-3 | Market share of affiliates in Retail Access Programs. | | |
| **Enron Statement No. 2** | **Direct Testimony of Paul D. Reising** Rates for unbundled services of Transmission, Ancillary, Energy Delivery and Revenue cycles separately computed and stated. | | |
| **Exhibit 2 PDR-1** | Educational and employment background of P.D. Reising. | | |
| Exhibit 2 PDR-2 | Definition and Description of Ancillary Services. | | |

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|---|---|---|---|
| **Exhibit 2 PDR-3** | Summary of Functional Costs. | | |
| **Exhibit 2 PDR-4** | EPMI Proposed Class Rates | | |
| **Exhibit 2 PDR-5** | EPMI Class Cost Summary | | |
| **Exhibit 2 PDR-6** | pro forma Distribution Services Tariff | | |
| **Exhibit 2 PDR-7** | Energy Delivery Rate Design | | |
| **Enron Statement No. 3** | **Direct Testimony of Jeffrey A. Brown** Non-wire services, metering, meter-reading, billing and information services. "Open architecture" communication systems. | | |
| Exhibit 3 JAB-1 | Customer Account Services: Billing System Opportunities (representative example) | | |
| Exhibit 3 JAB-2 | Customer Account Services: Third Party Billing Services (representative example) | | |
| Exhibit 3 JAB-3 | Non-Wire Products and Services: "Endless Possibilities" | | |
| Exhibit 3 JAB-4 | Non-Wire Communications Network: Conceptual Model | | |
| Exhibit 3 JAB-5 | Metering and Billing Cycle | | |
| **Enron Statement No. 4** | **Direct Testimony of Gayle Muench** Unbundling of billing and bill format; billing options ("Supplier Complete Bill Option"); phase-in of competition; customer selection and "slamming"; customer information ("Customer Education Program"); Duquesne's Universal Service Program in a competitive environment. | | |
| Exhibit 4 GM-1 | DQE Position on Competition | | |
| Exhibit 4 GM-2 | DQE Overview of Competition | | |
| **Enron Statement No. 5** | **Direct Testimony of Lynn R. Coles** "Pro Forma Supplier Tariff." Access to point-to-point transmission service. EDC charges; minimum contract periods; planning reserves. | | |

| | | | |
|---|---|---|---|
| Exhibit 5 LRC-1 | Summary of educational background and general experience in electric utility industry. | | |
| Exhibit 5 LRC-2 | Proposed Electric Generation Supplier Tariff. | | |
| Exhibit 5 LRC-3 | GPU Market Line: Energy market prices; viability payments, all-in market line; market clearing prices. | | |
| **Enron Statement No. 1.1** | **Surrebuttal Testimony of James D. Steffes** Response to Duquesne witnesses Hoffman and Allison. | | |
| **Enron Statement No. 2.1** | **Surrebuttal Testimony of Paul D. Reising** Responses to rebuttal testimony of Duquesne witness Lahtinen; IBEW witness Moran; and OCA witness Alexander. | | |
| **Exhibit 2.1 PDR-8** | Revised functional cost of service summary. | | |
| **Exhibit 2.1 PDR-9** | Revised versions of class-based T & D charges (original Exhibit 2 PDR-4). | | |
| **Exhibit 2.1 PDR-10** | Revised versions of voltage differentiated rates (original Exhibit 2 PDR-5). | | |
| **Enron Statement No. 3.1** | **Surrebuttal Testimony of Jeffrey A. Brown** Responses to Duquesne witness Allison; and IBEW witnesses Schmidt and Moran. | | |
| **Enron Statement No. 4.1** | **Surrebuttal Testimony of Gayle Muench** Responses to Duquesne witnesses Allison, Hoffman and Flynn; OCA witness Alexander; and IBEW witness Moran. | | |
| **Enron Statement No. 5.1** | **Surrebuttal Testimony of Lynn R. Coles** Responses to rebuttal testimony of IBEW witness Moran; and witnesses Irvin and Karl. | | |

## CERTIFICATE OF SERVICE

I hereby certify that I have this day served a true copy of the foregoing document via Hand Delivery, Federal Express, facsimile or first class mail, postage pre-paid upon the participants, listed below, in accordance with the requirements of 52 Pa. Code § 1.54.

Kandace Melillo, Esq.
Office of Trial Staff
PA Public Utility Commission
Pitnick Bldg., 3rd Fl.
901 North 7th St, Rear
Harrisburg, PA 17102

John S. Moot, Esq.
Kurt W. Bilas, Esq.
Skadden, Arps, Slate, Meagher
& Flom, LLP
1440 New York Ave., NW
Washington, DC 20005

Larry R. Crayne, Esquire
Duquesne Light Company
411 Seventh Ave.
P.O. Box 1930
Pittsburgh, PA 15230-1930

Angela T. Jones, Esquire
Office of Small Business Adv.
Suite 1102, Commerce Bldg.
300 North Second Street
Harrisburg, PA 17120

Brian Kalcic
Excel Consulting
Suite 720-T
225 S. Meramec Ave.
St. Louis, MO 63105

Mary Ann Ralls, Esquire
Duane, Morris & Heckscher LLP
Suite 700
1667 K Street, NW
Washington, DC 20006-1608

Scott J. Rubin, Esquire
3 Lost Creek
Selinsgrove, PA 17870

Mary McFall Hooper, Esq.
PECO Energy Company
2301 Market Street S23-1
Philadelphia, PA 19103

Vickiren S. Aeshleman
QST Energy Inc.
Suite 300
300 Hamilton Blvd.
Peoria, IL 61602

David Hughes
4037 Ludwick Street
Pittsburgh, PA 15217

Brian A. Rider, President
Pennsylvania Retailers' Assoc.
224 Pine Street
Harrisburg, Pa 17101-1325

Patricia Armstrong, Esquire
Thomas, Thomas, Armstrong
& Niesen
212 Locust Street
P.O. Box 9500
Harrisburg, PA 17108-9500

Steven Baicker-McKeen, Esq.
Wanda Schiller, Esq.
Babst, Calland, Clements & Zomnir, PC
8th Floor, Two Gateway Center
Pittsburgh, PA 16222

Kenneth L. Wiseman, Esq.
Mark F. Sundback, Esq.
Andrews & Kurth, LLP
1701 Pennsylvania Ave., NW
Washington, DC 20006

Michael L. Kurtz, Esq.
David F. Boehm, Esq.
Boehm, Kurtz & Lowry
2110 CBLD Center
36 East Seventh Street
Cincinnati, OH 45202

Thomas P. Gadsden, Esq.
Morgan, Lewis & Bockius
2000 One Logan Square
Philadelphia, PA 19103-6993

David M. DeSalle, Esq.
Terrance J. Fitzpatrick, Esq.
Ryan, Russell, Ogden & Seltzer, LLP
800 N. Third St., Suite 101
Harrisburg, PA 17102-2025

Robert B. Weisenmiller
MRW& Associates, Inc.
1999 Harrison St., Suite 1440
Oakland, CA 94612-3517

Michael Reid, Director
Materials Management Services
Administrative Resources, Inc.
500 Commonwealth Drive
Warrendale, PA 15086-7513

Thomas J. Augspurger, Esq.
Midcon Corporation
Office of General Counsel
701 East 22nd St.
Lombard, IL 60148

William T. Hawke, Esq.
Kevin J. McKeon, Esq.
Malatesta, Hawke & McKeon
100 North 10th St.
P.O. Box 1778
Harrisburg, PA 17108

Joseph A. Dworetzky, Esq.
John P. Lavell, Jr., Esq.
Hangley, Aronchick, Segal & Pudlin
12th Fl., One Logan Square
Philadelphia, PA 19103

Alan J. Barak, Esq.
Environmentalists
1417 Blue Mountain Parkway
Harrisburg, PA 17112

Donald R. Ayersman, Jr., Esq.
1125 Denver Avenue
Morgantown, PA 26505

Mark J. McGuire, Esq.
Ronald N. Carroll, Esq.
Jenner & Block, Suite 1200
601 13th St., NW
Washington, DC 20005

Tim Merrill, Esq.
4 Penn Center West, Suite 200
Pittsburgh, PA 15276

Cindy Datig, Esq.
$1 Energy Fund
P.O. Box 42329
Pittsburgh, PA 15203

Paul E. Russell, Esq.
Pennsylvania Power and Light Company
2 North 9th Street
Allentown, PA 18101

David M. Boonin
New Energy Ventures East, LLC
1845 Walnut Street, Suite 2525
Philadelphia, PA 19103

Roger Clark, Esq.
The Environmentalists
905 Denston Drive
Andler, PA 19002-3901

Albert M. Benincasa, Esq.
Director, Regulatory Affairs
Skipping Stone
46 9th Ave.
Sea Cliff, NY 11579

Douglas F. John, Esq.
John & Hengerer
1200 17th St., NW, Suite 600
Washington, DC 20036

John O'Brien, Esq.
Wheeled Electric Power Company
50 Charles Lindburgh, Blvd., Suite 207
Uniondale, NY 11553

Rodney R. Akers, Esq.
Assistant City Solicitor
313 City-County Building
414 Grant Street
Pittsburgh, PA 15219

James P. Dougherty, Esq.
Robert A. Weishaar, Esq.
McNees, Wallace & Nurick
100 Pine Street
P.O. Box 1166
Harrisburg, PA 17108

Stephen J. Baron
J. Kennedy & Assoc. Inc.
Suite 475
35 Glenlake Parkway
Atlanta, GA 30328

Howard M. Louik, Esq.
Allegheny County Law Dept.
300 Fort Pitt Commons
445 Fort Pitt Blvd.
Pittsburgh, PA 15219

Robert J. Stefanko, Esq.
341 South Bellefield Ave.
Pittsburgh, PA 15213

Margaret Peters, Esq.
The Peoples Natural Gas Co.
625 Liberty Ave.
Pittsburgh, PA 15222-3197

John Stember, Esq.
Low Income Advocate Parties
1705 Allegheny Bldg.
429 Forbes Ave.
Pittsburgh, PA 15219

Kenneth Zielonis, Esq.
Stevens & Lee
Suite 310
208 North Third Street
Harrisburg, PA 17108-2090

Stephen L. Feld, Esq.
Pennsylvania Power Co.
1 East Washington Street
P.O. Box 891
New Castle, PA 16103-0891

Exeter Associates, Inc.
Suite 350
12510 Prosperity Drive
Silver Springs, MD 20904

Donald A. Kaplan, Esq.
Lisa M. Helpert, Esq.
Preston, Gates, Ellis & Rouvelas,
Meeds, LLP
Suite 500
1735 New York Ave., NW
Washington, DC 20006-4759

Gary A. Jeffries, Esq.
CNG Energy Services Corp.
One Park Ridge Center
P.O. Box 15746
Pittsburgh, PA 15244-0746

David Cruthirds, Esq.
Electric Clearinghouse, Ins.
Suite 5800
100 Louisiana
Houston, TX 77002-5050

Keith M. Sappenfield, II
Director of Marketing Support
NorAm Energy Management Inc.
P.O. Box 2628
Houston, TX 77252-2628

John R. Orr, Esq.
Duke Energy Trading & Marketing, LLC
One Westchester Center
Suite 650
10777 Wesheimer
Houston, TX 77042

Lawrence E. Moncrief, Esq.
1364 Silverton Ave
Pittsburgh, PA 15206

Samuel W. Braver, Esq.
Bruce A. Americus, Esq.
BUCHANAN INGERSOLL P.C.
One Oxford Centre, 20th Floor
301 Grant Street
Pittsburgh, PA 15219-1410

Irwin A. Popowsky, Esquire
Marisa A. Sifontes, Esquire
Office of Consumer Advocate
1425 Strawberry Square
Harrisburg, PA 17120

John Wilson, Executive Director
Community Action Assoc. of PA
222 Pine Street
Harrisburg, PA 17101

Robert Longwell

Date: February 9, 1998

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