PENNSYLVANIA PUBLIC UTILITY COMMISSION

Uniform Cover and Calendar Sheet

1. **REPORT DATE:** April 28, 1998	2. **BUREAU AGENDA NO.:** MAY-98-OSA-229*
3. **BUREAU:** Office of Special Assistants	
4. **SECTION(S):**	5. **PUBLIC MEETING DATE:** May 21, 1998
6. **APPROVED BY:** **Director:** C. W. Davis, 7-1827 **Supervisor:** R. H. Albert, 7-8108	
7. **PERSONS IN CHARGE:** P. Foster, G. Strella	DOCKETED JUN - 2 1998
8. **DOCKET NO.:** R-00974104, et al.	

9. (a) CAPTION (abbreviate if more than 4 lines)
(b) Short summary of history & facts, documents & briefs
(c) Recommendation

(a) Application of Duquesne Light Company for Approval of its Restructuring Plan under Section 2806 of the Public Utility Code

(b) On August 1, 1997, Duquesne filed a restructuring plan to implement direct access to a competitive market for the generation of electricity pursuant to Section 2806(d) of the Electric Generation Customer Choice and Competition Act. Numerous parties filed petitions or letters of intervention. Several parties filed Formal Complaints against Duquesne's Restructuring Plan. ALJ Corbett conducted Public Input Hearings on November 12-13, 1997, and evidentiary hearings were held on December 15-18, 1997. Briefs and Reply Briefs were filed. The ALJ's Recommended Decision was issued on March 25, 1998. Exceptions and Reply Exceptions were filed to the ALJ's Recommended Decision. At the Public Meeting of April 30, 1998, the Commission conducted a poll of one issue and unanimously adopted the motion of Chairman Quain disposing of all other issues in this proceeding.

(c) The Office of Special Assistants recommends that the Commission adopted a draft Opinion and Order which has been prepared consistent with the action taken at Public Meeting on April 30, 1998.

10. **MOTION BY: Commissioner** Chm. Quain — **Commissioner** Hanger - Yes
Commissioner Rolka - Yes
SECONDED: Commissioner Bloom — **Commissioner** Brownell - Yes

Chm. Quain and Vice Chm. Bloom - Dissenting in part (on Phase-in)

CONTENT OF MOTION: Staff recommendation adopted.

Statement of Commissioner John Hanger attached.

PENNSYLVANIA PUBLIC UTILITY COMMISSION
Harrisburg, Pennsylvania

DUQUESNE LIGHT COMPANY
APPLICATION FOR APPROVAL OF
RESTRUCTURING PLAN FILED
AUGUST 1, 1997

PUBLIC MEETING -
MAY 21, 1998
MAY-98-OSA-229*
DOCKET NO. R-00974104,
ET AL.

STATEMENT OF COMMISSIONER JOHN HANGER

This final order marks the start of a new day for the families and businesses of Duquesne Light Company. During my many visits to Pittsburgh, the customers of Duquesne Light Company have made it clear that they need relief from the second highest average rates in Pennsylvania. That relief is now on the way.

This decision empowers customers with a system average shopping credit of 4.00 cents per kilowatt-hour in 1999. The shopping credit will rise to about 4.22 cents per kilowatt-hour in 2000 if the merger is completed. These shopping credits could allow customers to cut their total electric bills by about 15%.

The shopping credits in this decision are higher than the pilot program system average shopping credit of 3.76 cents per kilowatt-hour that has been in effect since November 1, 1997. Approximately 26,000 customers in the Duquesne service territory have already chosen new electric suppliers and have cut significantly their electric bills using the pilot shopping credits. Consequently, the final order shopping credit of 4.00 cents will create more vigorous competition that can only benefit consumers even more.

This decision is particularly good news for long-suffering residential customers who have paid the highest electric rates of any customer class. Residential customers will have a shopping credit higher than the system average credit of 4.00 cents per kilowatt-hour, though the exact amount is not yet set. Unlike many larger users, residential customers have been completely captive ratepayers and have not received the special discount rates that larger users have leveraged from Duquesne by threatening to generate their own electricity. Today's decision that ends the monopoly may benefit most residential customers.

In this case, there does exist one complication that creates some uncertainty. If the merger is not completed and Duquesne pursues divestiture of its generation plants, the system average pilot shopping credit of 3.76 will continue until the sale of generation plants is completed. At that point, the shopping credit will be recalculated to reflect the result of the sale.

If Duquesne does pursue divestiture, Duquesne must address many issues that the order lists. Included in that list is the impact on its employees. Duquesne employees have worked in some cases at

the company for decades. They have families. They are part of communities. Just as treating fairly consumers and shareholders is important, treating fairly the employees of Duquesne is vital.

If there is no sale of generation plants, the final order treats fairly the shareholders of Duquesne by awarding $1,331,567,000. of stranded cost recovery. This large amount of stranded cost recovery will insure that Duquesne has an opportunity to make a successful transition to competition and to retain the financial strength needed to insure reliable electric service.

Stranded costs will be collected through a competition transition charge (CTC) set at a system average rate of 2.58 cents per kilowatt-hour in 1999. Stranded costs will be recovered from January 1, 1999 to December 31, 2005.

All these stranded costs have been and are included in the rates that customers have been and are paying. These stranded costs are not new costs or new charges. This is a critical point. But for the transition to competition, customers would have continued to pay for stranded costs for the next 30 years and would not have had the price reductions that the shopping credits will produce.

Apart from shopping credits and stranded cost recovery, this decision contains many other important provisions. The final order requires consumer education and provides a $10 million budget. A certain amount of confusion is inevitable as competition begins but this massive consumer education program will help ease the transition for consumers.

The decision expands universal service protections for low-income families. Electricity is a necessity of life. The Act requires universal service programs and this decision increases the universal service protections and services. These provisions are and will be literally life savers.

The final order also includes new environmental initiatives involving renewable energy and net metering. These initiatives combined with the ability of customers to now choose green power open new avenues for consumers to benefit the environment through their own daily energy choices.

The final order also implements the statutory rate caps for the unbundled generation, transmission, and distribution rates. These statutory rate caps will protect those customers that do not shop, and no customer is required to shop.

Most importantly, this decision will improve the economic environment of Pittsburgh. This decision will cut energy costs and help families and businesses pay their bills. It will help create and preserve jobs. This is no small matter in a globally competitive economy where average income Pennsylvania families work from January 1 to early February to just pay all their utility bills.

When I began urging that Pennsylvania should end the retail electric monopoly, I said that retail competition could be implemented in a way that helped all consumers, assisted the environment, protected vulnerable families, and treated fairly utilities. This decision does that. The promise of the Electricity Generation Customer Choice and Competition Act, therefore, is kept.

May 21, 1998
DATED

John Hanger
JOHN HANGER, COMMISSIONER

COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
P.O. BOX 3265, HARRISBURG, PA 17105-3265

IN REPLY PLEASE
REFER TO OUR FILE

May 29, 1998

R-00974104 &
R-00974104C0001-C0004

LARRY R CRAYNE
RICHARD S HERSKOVITZ
DUQUESNE LIGHT COMPANY
411 SEVENTH AVENUE 16-006
PITTSBURGH PA 15230-1930

KJR

Application of Duquesne Light Company
for Approval of its Restructuring Plan
Under Section 2806 of the Public Utility Code

To Whom It May Concern:

This is to advise you that an Opinion and Order has been adopted by the Commission in Public Meeting on May 21, 1998 in the above entitled proceeding.

An Opinion and Order has been enclosed for your records.

Very truly yours,

James J. McNulty,
Secretary

encls
cert. mail
law

See attached
for additional
parties of record

PENNSYLVANIA PUBLIC UTILITY COMMISSION
Harrisburg, Pennsylvania

DUQUESNE LIGHT COMPANY
APPLICATION FOR APPROVAL OF
RESTRUCTURING PLAN FILED
AUGUST 1, 1997

PUBLIC MEETING -
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May 21, 1998
DATED

John Hanger
JOHN HANGER, COMMISSIONER

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

Public Meeting held May 21, 1998

Commissioners Present:

John M. Quain, Chairman, Dissenting in part (on Phase-In)
Robert K. Bloom, Vice Chairman, Dissenting in part (on Phase-In)
John Hanger, Statement attached
David W. Rolka
Nora Mead Brownell

Application of Duquesne Light Company for Approval of Its Restructuring Plan Under Section 2806 of the Public Utility Code	R-00974104; R-00974104C0001-C0004

OPINION AND ORDER

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I. INTRODUCTION

Before the Commission for consideration and disposition is the Recommended Decision of Administrative Law Judge (ALJ) John H. Corbett, Jr., which was issued on March 25, 1998, relative to the above-captioned proceeding. Also before us for disposition are the Exceptions, identified below, to the Recommended Decision. Reply Exceptions were filed by the Parties as noted infra.

A. History of the Proceedings

On August 1, 1997, Duquesne Light Company (Duquesne or Company) filed with the Pennsylvania Public Utility Commission (Commission) a restructuring plan to implement direct access to a competitive market for the generation of electricity pursuant to Section 2806(d) of the Electricity Generation, Customer Choice and Competition Act (Act). 66 Pa. C.S. §§2801, et seq. With the appearance of the Commission's Office of Trial Staff (OTS), the following Parties petitioned to intervene in this proceeding: the Office of Consumer Advocate (OCA); the Office of Small Business Advocate (OSBA); Allegheny County; the City of Pittsburgh (City); the School District of Pittsburgh; Jim Ferlo, pro se; David Hughes, pro se; Allegheny Electric Cooperative, Inc.; System Council U-10 of the International Brotherhood of Electrical Workers (IBEW); PECO Energy Company (PECO); Pennsylvania Power Company; Armco, Inc.; NorAm Energy Management, Inc.; Duke Energy Trading & Marketing, LLC; the Pennsylvania Retailers' Association (PRA); Electric Clearinghouse, Inc.; Enron Power

Marketing, Inc. (Enron); QST Energy, Inc.; The Environmentalists (Env.);[1] Low Income Advocate Parties (LIAP); MidCon Gas Services Corporation; mc², Inc.; Allegheny Teledyne, Inc.; The Peoples Natural Gas Company; Hospital Shared Services and Administrative Resources, Inc. (HSS/ARI);[2] CNG Energy Services Corporation; New Energy Ventures East, LLC (NEV); Duquesne Industrial Intervenors (DII);[3] Metropolitan Edison Company and Pennsylvania Electric Company, individually and collectively trading as GPU Energy (GPU); Mid-Atlantic Power Supply Association (MAPSA); the Skipping Stone;[4] Pennsylvania Power & Light Company; Wheeled Electric Power Company; Dollar Energy Fund; The Eastern Group; the Pittsburgh Chapter of the NAACP; and the IBEW, Local 2357. No objection was raised to any of these requests to intervene. Motions for admission, pro hac vice, of counsel for various parties were granted without objection as well.

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[1] The Environmentalists' coalition consists of the following organizations: Citizen Power, Inc.; Citizens' Organization on Utility Policies; Clean Water Action; The Group Against Smog and Pollution; The Pennsylvania Public Interest Research Group; and The Sierra Club.

[2] HSS/ARI, together, represent the following entities: Allegheny General Hospital, Children's Home of Pittsburgh, Forbes Metropolitan Hospital, Forbes Nursing Center, Forbes Regional Hospital, Gateway Rehabilitation Center, Healthsouth Harmarville, LGAR Health & Rehabilitation Center, Ohio Valley General Hospital, Presby Senior Care/Allegheny, Riverview Center for Jewish Seniors, St. Clair Hospital, Vincentian Home, South Hills Health System, and the University of Pittsburgh Medical Center. HSS/ARI M.B. at 1-2, fn. 1.

[3] DII is an ad hoc association of Duquesne's large industrial and institutional customers including: BOC Gases; General Motors Corporation; J&L Specialty Steel Company, Inc.; LTV Steel Company, Inc.; Nabisco, Inc.; Nova Chemicals, Inc.; and U.S. Steel Group, a unit of USX Corporation.

[4] The Skipping Stone describes itself as an energy consulting firm specializing in the deregulation of the electric industry. It represents a number of power marketers and aggregators who plan to do business in Pennsylvania.

The OCA (at Docket No. R-00974104C0001), City (at Docket No. R-00974104C0002), the Community Action Association of Pennsylvania (CAAP)[5] (at Docket No. R-00974104C0003), DII (at Docket No. R-00974104C0004), LIAP, Environmentalists, and the Pittsburgh Chapter of the NAACP filed Complaints against the restructuring plan. Answers thereto were waived by the presiding ALJ with the consent of the Parties.

A Prehearing Conference was held on September 4, 1997.[6] Duquesne, the OTS and the OCA submitted Prehearing Memoranda. When agreement could not be reached at the Prehearing Conference, the Parties held an informal telephonic conference on September 10, 1997, to discuss a litigation schedule.[7] On this latter date, the ALJ issued a Prehearing Order which, among other things, established a litigation schedule for this proceeding. All Parties agreed they would not object to the Commission issuing its final Opinion and Order on this Application by May 29, 1998, which was more than nine

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[5] CAAP is a statewide association of local community action agencies in Pennsylvania whose primary mission is to serve the needs and represent the interests of low income citizens.

[6] This conference was held jointly with the restructuring application of West Penn Power Company (West Penn) at Docket No. R-00973981 with ALJ Larry Gesoff co-presiding.

[7] These conferences were held jointly with the West Penn restructuring proceeding at Docket No. R-00973981, because Duquesne and West Penn filed their restructuring plans on the same date and, as a result, both proceedings were on the same statutory timetable. Also, the parent companies of Duquesne and West Penn filed a merger application at Docket No. A-110150F0015. The two restructuring proceedings are not consolidated nor is either restructuring proceeding consolidated with the merger application.

months after the Application was filed, as directed in the Act.[8] Altogether, a total of ten Prehearing and Interim Orders were issued in this case concerning various matters. In addition, a Protective Order for proprietary material applying to all Parties in this proceeding was issued on October 1, 1997. Further Prehearing Conferences scheduled for October 21, 1997 and December 9, 1997, were canceled.

In addition to Duquesne, the following Parties filed Statements of Prepared Testimony, together with numerous supporting exhibits: the OTS, the OCA, the OSBA, City, DII, Enron, Environmentalists, HSS/ARI, IBEW, MAPSA, NEV, PRA, CAAP,[9] and David Hughes. Evidentiary hearings to cross-examine witnesses supporting prefiled prepared written testimony for Duquesne were held in the Commission's offices in Pittsburgh on December 15-18, 1997. These hearings generated an additional 1,075 pages of notes of testimony. Further evidentiary hearings scheduled for January 5-9, 1998, to cross-examine witnesses supporting prefiled prepared written testimony for the aforementioned intervenors were canceled when Duquesne, together with all of the active intervenors, agreed to allow this testimony to be moved into the record without objection while waiving cross-examination. All active Parties filed first and second Stipulations evidencing their agreement with this procedure.

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[8] 66 Pa. C.S. §2806(f). Without the waiver, the run date for a Commission Opinion and Order on this Application expired April 30, 1998.

[9] The CAAP, a corporation, was not represented by counsel. Corporations must be represented by an attorney-at-law in adversary proceedings before the Commission. See, 52 Pa. Code §1.22. However, all active Parties stipulated to the introduction of CAAP's and other intervening Parties' prepared written testimony because no Party wished to cross-examine the witnesses sponsoring the testimony. Therefore, the presiding ALJ admitted their statements into the record.

The record in this proceeding closed on January 23, 1998. The following Parties filed both Main and Reply Briefs: Duquesne, the OTS, the OCA, the OSBA, DII, HSS/ARI, PRA, IBEW, Enron, and MAPSA. The following Parties filed Main Briefs only: City, Environmentalists and LIAP (jointly), CAAP, Mr. Hughes, NEV, GPU, and PECO.

The Recommended Decision of ALJ Corbett was issued on March 25, 1998. The following Parties filed Exceptions to the Recommended Decision: on April 10, 1998, CAAP, and IBEW; on April 13, 1998, HHS/ARI, Duquesne, and David Hughes; on April 14, 1998, PECO, Enron, Env., MAPSA, DII, the OSBA, PRA, the OCA, and the OTS. The City filed a Letter on April 14, 1998, advising that it would not be filing Exceptions. Reply Exceptions were filed on April 20, 1998, by IBEW; on April 22, 1998, by the OTS; on April 23, 1998, by Duquesne and HSS/ARI; on April 24, 1998, by the OCA, MAPSA, PRA, the OSBA, DII, and Enron.

B. Overview of the Act

On December 3, 1996, Governor Thomas J. Ridge signed into law the Electricity Generation Customer Choice and Competition Act, P.L. 802, No. 138, effective January 1, 1997, 66 Pa. C.S. §§ 2801-2812 (the "Act"). The Act fundamentally restructures the provision of retail electric service in Pennsylvania by mandating the direct access to a competitive electric generation market by retail customers. 66 Pa. C.S. § 2802(12). Direct access to the competitive electric generation market is accomplished by the retail customer's choice of electric generation supplier (EGS). Thus, direct access to competitive electric generation will begin with phased implementation, beginning in January 1, 1999, following a period of Pilot Programs. 66 Pa. C.S. § 2806(b).

The Act further requires all jurisdictional electric utilities (EDCs) to file restructuring plans for review and approval by the Commission. 66 Pa. C.S. § 2806(d). The Act requires the restructuring plan address the following matters: (1) establishment of reasonable terms and conditions for open access retail competition; (2) the calculation and recovery of reasonable stranded costs through a proposed competitive transition charge (CTC); (3) the establishment of unbundled rates for the generation, transmission and distribution of electricity; and (4) the provision of continued customer protections, particularly the continuation of safe and reliable service and programs for the assistance of low-income customers.

On January 24, 1997, at Docket No. M-00960890, F0005, this Commission established a schedule for filing of the restructuring plans. On April 1, 1997, Duquesne filed an Application for Approval of its Restructuring Plan at the above-captioned docket. Notice of the proposed Restructuring Plan was provided to Duquesne's customers through billing inserts and in newspapers of general circulation in Duquesne's service territory.

C. Public Input Testimony

Pursuant to public notice, three hearings were held at two locations in southwestern Pennsylvania to receive public comment upon the proposed restructuring plan. Public Input Hearings were held as follows: on November 12, 1997, in Beaver Falls, Pa.; and on November 13, 1998, two hearings in Pittsburgh, Pa. These hearings were also held to receive public comment upon the proposed merger of Duquesne Light Company and West Penn Power Company in the Joint Application of DQE, Inc., Allegheny Power System, Inc., et al., at Docket No. A-110150F0015. The majority of the

people appearing at these hearings testified about their concerns relating to the proposed merger plan.

D. Summary of Key Determinations in the Proceeding

Duquesne has a current bundled system average rate of 8.93 cents/kwh, a rate that is more than 10% lower than the Pennsylvania electric utility with the next lowest rate. Duquesne's rates are about 21% above the national average. Pennsylvania's statewide average electric rate is about 15% higher than the national average. Duquesne's customers will still be able to achieve savings by shopping and will be protected against rate increases pursuant to the rate caps in the Act whether they shop or not.

For Shopping Customer:

a. Existing Bundled Rate	8.93
b. Unbundled T&D	2.35
c. Unbundled G	6.58
d. CTC	2.58
e. "Shopping Credit" (e=a-b-d)	4.00

The CTC was developed to permit Duquesne to recover 1.332 billion in stranded and transition costs until January 1, 2005. The amount includes $951 million for utility generation, $339 million in regulatory assets, that includes $10 million for consumer education. Duquesne is permitted to recover 100% of its documented jurisdictional stranded costs.

The following Table summarizes the unbundling of existing rates, the Competitive Transition Charge ("CTC") and the Shopping Credit that will be available on

a system-wide average basis in 1999 as a result of today's decision. Each customer class will experience somewhat different results that will be finalized upon acceptance of Duquesne's filing in compliance with today's decision. In the following Table, "Unbundled T&D" is the rate for transmission and distribution services that customers now pay and will continue to pay. "Unbundled G" is the rate that all customers now pay Duquesne for generation and only non-shopping customers will continue to pay Duquesne for generation. The CTC is a transition period charge that all shopping customers will pay Duquesne to compensate for stranded costs. The Shopping Credit is the amount leftover to a shopping customer to purchase generation from a competitive Electric Generation Supplier ("EGS").

For Customer Not Shopping:	System Average
a. Existing Bundled Rate	8.93
b. Unbundled T&D	2.35
c. Unbundled G	6.58
d. Total Price Paid to Duquesne (d = a = b+c)	8.93

II. PHASE-IN OF CUSTOMER CHOICE

A. Method of Customer Selection

1. Positions of the Parties

Section 2806(b) of the Act, 66 Pa. C.S. §2806(b) provides that:

> Recognizing that approximately 5% of the peak load will have retail access through pilot programs, the following schedule for phased implementation of retail access shall be adhered to unless a determination is made by the commission under subsection (c):
>
> (1) As of January 1, 1999, a maximum of 33% of the peak load of each customer class shall have the opportunity for direct access.
>
> (2) As of January 1, 2000, a maximum of 66% of the peak load of each customer class shall have the opportunity for direct access.
>
> (3) As of January 1, 2001, all customers of electric distribution companies in this Commonwealth shall have the opportunity for direct access.
>
> (4) The Commission shall establish regulations specifying that, within each customer class, the customers that are eligible for direct access prior to full direct access shall be determined on a first-come-first-served basis unless otherwise determined by the commission ... to prevent competitive disadvantages among similarly situated customers within a customer class.

Duquesne proposes to phase-in direct retail access in three equal increments of one-third of the peak load of each customer class annually starting January

1, 1999, so that all customers will be eligible for direct retail access by January 1, 2001. Residential and small commercial customers will be selected for phase-in to customer choice by zip code-based geographic areas of choice (GACs) based on interest in its pilot program. Within those areas, customers will have first-come, first-served rights when their area is phased-in. Other commercial and all industrial customers will be selected based on SIC code-based "market segments," with the order based on the percentage response of customers within the segments to the Company's pilot solicitation. (R.D., p. 9).

Duquesne argued that its plan for residential and small commercial customers promotes an orderly, rather than a random, transition to customer choice for small customers, while also using the first-come, first-served method. As to its plan for industrial and larger commercial customers, Duquesne claims two key benefits. First, it uses the results of the first-come, first-served pilot enrollment, so the market segments that demonstrated the most interest in choice will have the first opportunity for it during the transition period. Second, it eliminates potential disadvantages within market segments that an open enrollment will create, with certain competitors having choice and others not (because of oversubscription). (R.D., pp. 9-10).

The OCA urged the rejection of Duquesne's proposal for selection of residential customers; instead, the OCA recommended adoption of a first-come, first-served approach. The OCA found no compelling reason to phase-in customer choice for residential customers by geographic area. First, the OCA argued that suppliers will typically market throughout an entire service territory, as opposed to the smaller zip code-based areas that Duquesne proposed. Second, the OCA claimed Duquesne has not shown that its proposal is fairer to lower socio-economic classes, as the Company asserted. Adoption of a first-come, first-served approach, where motivated residentials can choose

to participate in the competitive market, will, according to the OCA, create the robust market that the General Assembly intended. (R.D., pp. 11-12).

The OSBA conditionally accepted Duquesne's phase-in proposal because the Company indicated that it will favorably treat a complainant within the dispute resolution process if a customer shows: "a) their business has been misclassified or b) other businesses with the same product or service have received a competitive advantage." (R.D., p. 13).

However, the OSBA claimed a first-come, first-served approach will likely result in an under-representation of small business customers in the first two steps of the phase-in. Duquesne's small business customers receive service via Rate GS/GM, which is available to all non-residential customers whose billing demands do not exceed 300 kW. The OSBA argued that the high end, large account customer within the GS/GM class will be over-represented in the first two steps of the phase-in under the first-come, first-served system, while the small account customers will be under-represented. (R.D., pp. 14-15).

The OSBA recommended, if the Commission adopts a first-come, first served procedure, that the Rate GS/GM class group be segmented into "Small Rate GS/GM" and "Large Rate GS/GM," with segment limitation for the Small Rate GS/GM at a 40-kilowatt load. The OSBA recommended that the Company designate progressively one-third of the peak load of the Small Rate GS/GM segment over the phase-in period and the same for the Large Rate GS/GM segment, with the total of the segmented load levels eligible for a given year equal to that allowed for Rate GS/GM as a whole. (R.D., p. 15).

DII found Duquesne's customer selection proposal inappropriate under the Act. DII noted that the Act directs that the percentage of participation be determined based on "the peak load of each customer class." (66 Pa. C.S. §2802(b)(1) and (2)). DII argued that Duquesne's proposal merges the commercial and industrial customer classes, and does not treat each customer class separately as required by the Act. DII claimed that the Act's clear language mandates consideration of each class separately. Additionally, the Company admitted that phasing an entire segment, as a group, may cause it to exceed the maximum participation levels in the Act (N.T. 1027, R.D., p.16).

The PRA urged rejection of Duquesne's proposal and, instead, recommended adoption of the phase-in methodology that the DII favors. (R.D., p. 20). The PRA noted that Duquesne rejected this approach. The PRA claimed that Duquesne's proposal lacks specificity as to the standard industrial codes (SIC) that will be utilized, and some market segments may compete with each other. Consequently, the PRA argued that competitive disadvantages will be administratively created under Duquesne's proposal. (R.D., pp. 20-21).

The Environmentalists preferred a first-come, first-served approach, which allows customers to volunteer to shop. The Environmentalists suggested that if too many residential and small commercial customers sign up for one phase a lottery be held to determine who is able to join. The Environmentalists argued that for large commercial and industrial customers, if the number of customers signing up exceeds the allowance, then each volunteering customer should be allowed to participate with a pro-rata share of its load. The Environmentalists noted that the Commission adopted this approach in PECO Energy, which they support. They further noted the Commission adopted the

principle of customer self-selection in the Retail Access Pilots proceeding[10] and recommend it as sound policy for this proceeding as well. (R.D., pp. 23-24).

Enron submitted that Duquesne's process will result in far less than 33% of its customers (or 66% if the first two phase-in steps are conducted more or less simultaneously, as discussed below) having access to customer choice. Enron contended that the GAC and SIC method Duquesne advances will indiscriminately prevent customers who desire to participate in the competitive market place from attempting to take advantage of competition. Enron argued that small commercial customers will also be disadvantaged from one neighborhood to another. (R.D., p. 24). Enron argued that the Commission rejected the "GAC/SIC process" as Duquesne proposed in the Pilot proceeding[11] and urged the adoption of the procedure established by the Commission in PECO Energy as the most reasonable method of customer selection. (R.D., p. 25).

Likewise, MAPSA urged rejection of Duquesne's proposal as the Commission did with a substantially similar approach in the Opinion and Order entered in Duquesne's pilot program. MAPSA claimed that Duquesne's artificial imposition of constraints upon the process will restrict the amount of load purchased from alternative suppliers and unnecessarily complicate the enrollment process. MAPSA contended that Duquesne's arguments regarding building on experience gained from the Pilot Program are irrelevant. During the Pilot Program, MAPSA noted that Duquesne did not employ

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[10] Petition for Approval Of Retail Access Pilot Programs, Docket Nos. P-00971168, et al., (Opinion and Order on Pilot Program Implementation entered August 21, 1997).

[11] 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.

the process it proposed to employ following restructuring. Therefore, MAPSA contended that no party has experience with the methodology Duquesne proposed. (R.D., pp. 26-27).

2. ALJ's Recommendation

The ALJ recommended that we reject Duquesne's proposed method to select customers for phase-in to direct retail access because the Commission has already determined a pure first-come, first-served selection process is the fairest and most orderly process for customer selection. PECO Energy, Slip Op. at 47-49. In accordance with this determination, the ALJ recommended that beginning July 1, 1998, Duquesne should conduct an open enrollment period for residential customers on a "first-come, first-served" basis. The ALJ asserted that if less than 33% of the residential customer load enrolls as of September 30, 1998, the ALJ recommended that Duquesne should notify all customers who have volunteered as of that date that they can participate in the phase-in beginning January 1, 1999. Id. at 48. If more than 33% of the customer load enrolls as of September 30, 1998, Duquesne should have an independent party conduct a lottery to determine which customers may participate in the phase-in beginning January 2, 1999. Id.; See, also, PECO Energy Restructuring Order, Slip Op. at 22.

With respect to large industrial customers, the ALJ also found that no apparent reason exists for departure from a uniform statewide approach on this issue. The ALJ noted that in the PECO Energy Order, Slip Op. at 22, the Commission departed from the pure "first-come, first-served" selection process for large industrial customers. The ALJ observed instead that, subscription for large industrial customers for each stage of phase-in will occur on a first-come, first-served basis, unless a class load is oversubscribed. The ALJ concluded that in such event, each customer nominating a

portion of load in the oversubscribed class will experience a pro-rata reduction in their nominated load, so the total load available for direct access in that class meets the Act's 33% requirements for that phase. (66 Pa. C.S. §2806(b)).

For small business customers, the ALJ recommended adoption of the proposal of the OSBA for customers receiving service from Duquesne via Rate GS/GM, which is available to all non-residential customers whose billing demands do not exceed 300 kW. Thus, the ALJ recommended that Duquesne segment the Rate GS/GM class group into "Small Rate GS/GM" and "Large Rate GS/GM." The OSBA suggested a segment limitation for the Small Rate GS/GM at a 40-kilowatt load; however, the OSBA noted that the Company may determine a more appropriate breakpoint after a detailed billing frequency analysis of all Rate GS/GM accounts. The OSBA noted that thereafter, customers within each class may designate their loads in the same manner described above for large industrial customers until one-third of the peak load of each class for that phase-in period is reached. (R.D. pp. 28-30).

For all other customers, the ALJ recommended that the pure "first-come, first-served" approach described above for residential customers should apply. The ALJ further recommended that the Commission consider the Environmentalists' "Better Choice Plan" when it promulgates its regulations required by Sections 2807(e)(2) and (3) of the Act, consistent with the Commission's action in PECO Energy, Slip Op. at 135. (R.D., p. 30).

3. Parties' Exceptions

Two parties except to the ALJ's recommendations concerning the method of customer selection. The Environmentalists argue, in their Exceptions, that the ALJ

erred in rejecting the "Better Choice Plan." The Environmentalists submit that under the "Better Choice Plan," a more diverse market is created because alternative suppliers can volunteer to become part of the default supplier which serves customers who fail to choose. (Environmentalists Exc., p. 2).

The PRA argues, in its Exceptions, that 100% of large commercial customers should be permitted minimally to nominate 33% of their load in each year of the three year phase-in period, assuming no acceleration of the phase-in period. The PRA contends that all commercial customers should be permitted to shop for part of their load on January 1, 1999. (PRA Exc., pp. 8-10).

It its Reply Exceptions, the OCA argues that the "Better Choice Plan" should be considered at a later date. (OCA R. Exc., p. 24).

4. Resolution

We shall adopt the position of the ALJ, which supports (1) system-wide, "first-come, first-served," selection for residential customers as modified below; (2) the OSBA proposal to split small commercials on a "first-come, first-served," basis, and (3) DII and PRA's pro-rata subscription for industrial and large commercial customers.

In making this determination, we reject Duquesne's proposed method to select customers for phase-in to direct retail access to the competitive generation market. In moving toward this market the Legislature, in the Act, directed that " . . . the Commonwealth must resolve certain transitional issues in a manner that is fair to customers, electric utilities, investors, the employees of electric utilities, local communities, . . . and other affected parties." 66 Pa. C.S. §2802(8). Further, "[t]he

procedures under this chapter provide for a fair and orderly transition from the current regulated structure to a structure under which retail customers will have direct access to a competitive market for the generation and sale or purchase of electricity." 66 Pa. C.S. §2802(13). Therefore, consistent with the Act, whichever method is determined to be appropriate for customer selection must assure a fair and orderly transition.

Because, as argued by the OCA, the competitive electric market is larger than a zip code area and because Duquesne has not shown its plan to fairer to lower socio-economic classes, we determine a first-come, first-served selection process as the fairest and most orderly process for customer selection as was done in PECO Energy Order, Slip Op. at 47-49. Based on our review of the record as developed, we conclude that it is reasonable, appropriate, and in the public interest to direct Duquesne to implement this approach for residential customers. Beginning July 1, 1998, Duquesne will conduct an open enrollment period for residential customers on a first-come, first-served, basis. If less than 33% of the customer load for that tariff class enrolls as of August 14, 1998, Duquesne shall notify all customers who have volunteered as of that date that they can participate in the phase-in beginning January 1, 1999. (Id. at 48). If more than 33% of the customer load for that tariff class enrolls as of August 14, 1998, they shall be included in the second phase of enrollment for January 2, 1999. (Enrollment Procedures re: EDCs and EGS during Phase-in, Docket No. M-00960890F0014, Adopted May 21, 1998).

We note that in PECO Energy, Slip Op. at 22, we departed from a strict, "first-come, first-served," selection process for large industrial customers. Instead, subscription for large industrial customers for each stage of the phase-in will occur on a first-come, first-served basis, unless a class load is oversubscribed. In such event, each customer nominating a portion of load in the oversubscribed class will experience a pro-

rata reduction in their nominated load, so the total load available for direct access in that class meets the 33% load for that phase. (66 Pa. C.S. §2806(b)). This adjustment reflects the concern for competitive disadvantages this class may otherwise face, as the intervenors in this Application so eloquently argue. PRA has requested similar treatment for customers above 300 kW. Since no persuasive argument exists in the record to support a less than uniform approach to this issue, we will adopt the same method here for the large customers above 300 kW, as recommended by the ALJ.

We did not address the same competitive concerns of smaller commercial customers in the PECO Energy case. We will adopt the proposal of the OSBA, as herein modified, as it relates to small business customers receiving service from Duquesne via Rate GS/GM, which is available to all non-residential customers whose billing demands do not exceed 300 kW. We do this to address OSBA's concerns that Rate GS/GM contains customers with inherently diverse billing demands, usage patterns and physical size. (OSBA St. 1R at 12-13). Thus, we find that Duquesne should segment the Rate GS/GM class group into "Small Rate GS/GM" and "Large Rate GS/GM." (Id. at 14).

The OSBA suggests a segment limitation for the Small Rate GS/GM at a 40-kilowatt load; however, we recognize that the Company may determine a more appropriate breakpoint after a detailed bill frequency analysis of all Rate GS/GM accounts. (Id). Therefore, we determine that for all industrial customers with usage over 300 kW and large commercial customers with usage in the over 40 kW range, subscription for each stage of phase-in will occur on a first-come, first-served basis, unless a class load is oversubscribed. We hasten to add that in such event, each customer nominating a portion of load in the oversubscribed class will experience a pro-rata reduction in their nominated load, so the total load available for direct access in that class meets the Act's 33% requirements for that phase. (66 Pa. C.S. §2806(b)).

The small rate GS/GM and large rate GS/GM commercial customers shall be treated as separate classes for first-come, first served purposes. The same lottery procedure, as discussed above, shall be used for these classes, as well as for all other customer classes, as described above for residential customers. With regard to the Environmentalists' proposed "Better Choice Plan," as we decided in PECO Energy, Slip Op. at 135, we shall defer consideration of the plan until we promulgate regulations required by Sections 2807(e)(2) and (3) of the Act. 66 Pa. C.S. §2807(e)(2) and (3).

B. Timetable for Phase-In

1. Positions of the Parties

Duquesne proposed to phase-in direct retail access in three equal increments of one-third of the peak load of each customer class annually starting January 1, 1999, so that all customers will be eligible for direct retail access by January 1, 2001.

In recognition of the precedent established in PECO Energy, OSBA claimed that the phase-in established in PECO effectively makes the potential for competitive disadvantages to small business customers a one-year, rather than a two-year, problem. OSBA agreed that a phase-in consistent with PECO Energy addresses the statutory mandates of Section 2806(b) of the Act and minimizes potential competitive problems of small business customers. (R.D., p. 31).

DII proposed that Duquesne offer one-third of its load to direct access on January 1, 1999, the second one-third on January 2, 1999, and the final third on January 2, 2000. DII contented the Act established annual maximum participation targets as of

January 1, 1999, January 1, 2000, and January 1, 2001. DII asserted that the day after each target date, the next participation limit becomes effective. DII argued that the Act does not establish a one-year period in which only the minimum amount of load can have direct access; rather, the Act simply establishes the next target and a maximum level that cannot be exceeded on that date. DII also argued that customers in the Duquesne territory deserve the same accelerated access as the Commission provided to customers in PECO's service territory. See, PECO Energy, Slip Op. at 48-49. (R.D., pp. 30-31).

The PRA, the Environmentalists, and Enron contended that the Commission should establish a phase-in timetable for direct access in this case in the same manner as PECO Energy. Enron submitted that an accelerated phase-in, compared to Duquesne's proposal, is in the public interest, permitted by the clear language in the Act, and will bring the benefits of competition to more customers sooner. Enron argued that Section 2806(b) established the maximum "peak load of each customer class," which can be provided the opportunity for direct access "as of" or, in other words, not later than each date. Enron asserted that the plain language of that section states that "as of" a date certain, the maximum penetration of direct access shall not exceed a certain level. Enron submitted that by any reasonable reading, at any time after that date certain, the Commission has discretion to increase the penetration, as long as it does not exceed the next cap. (R.D., pp. 34-36).

MAPSA joined the foregoing intervenors in objecting to Duquesne's proposal. MAPSA also pointed to the phase-in approved in PECO Energy as the most appropriate method for eliminating the potential for discrimination and competitive disadvantages between similarly-situated customers. (R.D. p. 37).

GPU contended that the phase-in schedule that the Commission adopted in PECO Energy, and advocated here by others, cuts one full year (minus one day) out of the

phase-in schedule established in Section 2806(b). GPU noted that the Commission did not provide the rationale for its accelerated phase-in in PECO Energy. To GPU, it appears that the Commission may have adopted this schedule based on an interpretation of the words "as of," which appear at the beginning of subparagraphs (b)(1), (2), and (3) to mean "at the latest," rather than "beginning on." GPU argued that under this interpretation, the Commission could order an EDC to phase-in direct access to the second one-third of the peak load of each customer class on January 2, 1999, and the final one-third on January 2, 2000. (R.D., pp. 37-38).

GPU argued that this interpretation of Section 2806(b) of the Act is erroneous. Section 2806(b) establishes a three-step phase-in, beginning in January 1999 and ending January 1, 2001. GPU asserted that while an EDC and its customers may settle upon an expedited phase-in of direct access, thereby waiving the EDCs right under the Act to a more gradual phase-in, GPU claimed that the Commission may not unilaterally cut a year out of the process. (GPU M.B. at 5). GPU claimed that the language of Section 2806(c) supports its argument for two reasons. First, Section 2806(c) establishes January 1, 1999, as the "implementation date." In other words, January 1, 1999, is the date upon which the phase-in to direct access begins. Thus, the words "as of" at the beginning of Section 2806(b)(1) can only mean "beginning on." Second, GPU argued that the Legislature did not delegate discretion to the Commission in Section 2806 to adopt an accelerated phase-in schedule. (R.D., pp. 38-39).

PECO concurred with the position of GPU that the Legislature adopted a series of provisions in the Act which contemplate that customer choice will be phased in gradually over a three-year period. (66 Pa. C.S. §2806(b)). PECO strongly disagreed with the Commission's phase-in decision in PECO Energy; however, PECO claimed that fairness dictates that uniform phase-in schemes be imposed on all jurisdictional electric

utilities in Pennsylvania. Otherwise, PECO submitted that the spirit, and arguably the letter of the Act's reciprocity feature, will be violated. (R.D., p. 42). (We note a settlement concerning this issue has been reached with PECO, pursuant to which the phase-in schedule adopted in the Commission's Order will remain and all appeals of the case are expected to be withdrawn. This Settlement was unanimously approved by the Commission on May 14, 1998.)

2. ALJ's Recommendation

For the reasons GPU and PECO advanced concerning proper statutory construction, the ALJ recommends the Commission to reconsider the phase-in schedule for customer choice that it adopted in PECO Energy, Slip Op. at 47-49. The ALJ commented that (R.D., pp. 42-43) "As of" may mean "at the latest," which the Commission apparently attributed to the phase-in schedule in PECO Energy. The ALJ reasoned that on the other hand, "as of" may mean "beginning on," which GPU contended is the only reasonable construction, if one accepts the premise that Section 2806(c) establishes January 1, 1999, as the "implementation date" for the commencement of phase-in to direct access. The ALJ asserted that, given that premise, all of the remaining portions of the statute must be read "in pari materia," pursuant to Section 1932 of the Statutory Construction Act, 1 Pa. C.S. §1932, for the reasons GPU advances. Accordingly, the ALJ concluded that each of the subsections of Section 2806(b) must be interpreted to mean "beginning on" January 1, 1999, etc. For these reasons, the ALJ recommended that the Commission adopt the phase-in schedule favored by GPU and PECO.

3. Parties' Exceptions

The OSBA, Environmentalists, MAPSA, DII, PRA and Enron except to the ALJ's recommendation for (1) a phase-in over three years with a mandatory schedule in which one-third of the peak load of each customer class is given the opportunity for direct access in January of three successive years - 1999, 2000, and 2001, and (2) reconsideration of the accelerated phase-in schedule favored in PECO Energy. (R.D., pp. 42-43). Generally, the parties argue that neither the statutory construction argument, relied upon by the ALJ, nor the record provide sufficient justification for the Commission to reconsider its established precedent on the phase-in. (OSBA Exc., pp. 4-8; Env. Exc., p. 2; MAPSA Exc., pp. 1-2; DII Exc., pp. 2-3, R.Exc., p. 18; PRA Exc., pp. 10-11).

In its Exceptions, PECO concurred with the ALJ's determination that the Commission, in PECO Energy, misconstrued the Act's phase-in requirements. However, as previously noted, on May 14, 1998, the Commission approved a Settlement with PECO which maintains the phase-in plan contained in the Commission's December 23, 1997 Order. PECO has agreed to withdraw its appeal before the Commonwealth Court of Pennsylvania.

In its Reply Exceptions, Duquesne concurs with the ALJ's determination, arguing that an accelerated timetable represents a "distorted interpretation of the [Act]." (DLC Statement 6R at 10; R. Exc., p. 20).

4. Resolution

Section 2806(b) provides that:

> Recognizing that approximately 5% of the peak load will have retail access through pilot programs, the following schedule for phased implementation of retail access shall be adhered to unless a determination is made by the commission under subsection (c):
>
> (1) As of January 1, 1999, a maximum of 33% of the peak load of each customer class shall have the opportunity for direct access.
>
> (2) As of January 1, 2000, a maximum of 66% of the peak load of each customer class shall have the opportunity for direct access.
>
> (3) As of January 1, 2001, all customers of electric distribution companies in this Commonwealth shall have the opportunity for direct access.
>
> (4) ... within each customer class, the customers that are eligible for direct access prior to full direct access shall be determined on a first-come-first-served basis unless otherwise determined by the commission ... to prevent competitive disadvantages among similarly situated customers within a customer class.

We note that GPU and other parties argue that the Act requires one specific phase-in schedule of exactly 33% of load eligible for direct access exactly on each of the three dates specified above. These parties interpret Section 2806(b) of the Act to provide the Commission with no discretion concerning the phase-in schedule, except to extend the phase-in schedule pursuant to Section 2806(c).

The parties interpretation is not consistent with the plain language of Section 2806(b) of the Act. Any argument that the Commission has no discretion to

adopt a phase-in schedule within the parameters of Section 2806(b) ignores the phrases "a maximum of" and "as of" that give the Commission discretion. Furthermore, rules of statutory construction do not permit an interpretation of the Act in a manner that would render specific language superfluous. The Legislature intended "a maximum of" to mean "exactly," the phrase "a maximum of" would not have been used. If the legislature intended "as of" to only mean "commencing on," the legislature would have said "commencing on."

Moreover, the general rule in subsection (a), "consistent with the commission's discretion under this section," grants the Commission discretion to fashion a phase-in within the guidelines of 2806(b). If the Commission's discretion were limited to extending the schedule pursuant to subsection (c), the grant of discretion that appears in section (a) would have been written only into subsection (c), and the language in subsection (b) would have provided a precise load for phase-in on a precise date instead of using the phrases "a maximum of" and "as of."

We do agree that the phrase "as of" has several meanings in the English language, including "on," "no later than", and "by". However, consideration of the entire statutory language does not support the argument that the language may only be interpreted to mean "commencing on." Even if the phrase "as of" is interpreted to mean "on," the schedule adopted in PECO Energy is fully consistent with the language of the Act. We note that on January 1, 1999, there will be a maximum of 33% eligible for direct access; on January 1, 2000, there will be a maximum of 66% eligible for direct access; and on January 1, 2001, all customers will be eligible for direct access.

Similarly, if the phrase "as of" is interpreted to mean "by," our schedule is fully consistent with the language of the Act. By January 1, 1999, there will be a

maximum of 33% eligible for direct access; by January 1, 2000, there will be a maximum of 66% eligible for direct access; and by January 1, 2001, all customers will be eligible for direct access. If the phrase "as of" is interpreted to mean "no later than," the schedule that we support is fully consistent with the language of the Act. No later than January 1, 1999, there will be a maximum of 33% eligible for direct access; no later than January 1, 2000, there will be a maximum of 66% eligible for direct access; and no later than January 1, 2001, all customers will be eligible for direct access.

In contrast, the interpretation that "as of" may only mean "commencing on" requires a conflict with the very provision being interpreted. Section 2806(a) defines a "transition and phase-in period beginning on the effective date of this chapter (January 1, 1997) and ending, consistent with the Commission's discretion under this section, January 1, 2001. " Section 2806(b) begins with the statement, "Recognizing that approximately 5% of the peak load will have direct access through pilot programs..." Clearly the transition began on January 1, 1997, the effective date of the Act, and the phase-in to direct access began with the phase-in of 5% of customer load during the pilots. Interpreting "as of" to mean "commencing on" would require ignoring the cited provisions.

It has been argued that "as of" must mean "commencing on" because otherwise the Commission could have phased-in competition prior to January 1, 1999. This argument must also fail. The statute may have permitted increasing beyond 5% to 33% prior to January 1, 1999. The fact that we did not so exercise our discretion does not mean that "as of" must mean "commencing on."

Lastly, we note the statutory directive in Section 2806(b)(4) grants the Commission both the discretion and the responsibility to adopt a phase-in plan that

"prevents competitive disadvantages among similarly situated customers within a customer class." The above phase-in schedule is the simplest, most effective means to minimize competitive disadvantages.

We have carefully reviewed the record developed and we find that different phase-in schedules for competition in different parts of the Commonwealth would advantage or disadvantage customers depending upon where they live and through which utility they are served.

In PECO Energy, this Commission ordered that a maximum of 33% of the non-coincident peak load of each tariff class shall have the opportunity for direct access on January 1, 1999, a maximum of 66% shall be eligible for direct access on January 2, 1999, and that all customers shall be eligible for direct access on January 2, 2000. To deny customers outside the PECO service territory the same schedule that PECO customers will have would be to disadvantage the rest of Pennsylvania.[12] Avoiding such a result is one of the reasons why Section 2806 gives the Commission discretion and why we must exercise such discretion accordingly.

This schedule is in the public interest in order to provide the benefits of direct access expeditiously. Moreover, we find that the schedule is appropriate both to minimize competitive disadvantages among customers and among EDCs. We conclude that this schedule will facilitate an orderly transition without confusion due to different phase-in schedules for different EDCs in overlapping media markets.

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[12] As previously noted, on May 14, 1998, the Commission approved the Joint Petition submitted by the parties in PECO Energy which maintains this phase-in plan as contained in the Commission's December 23, 1997 Order. Accordingly, we have an element of certainty that the phase-in will be implemented as prescribed, and we foresee no legal impediments to this process.

C. Summary and Conclusion

In summary, the ALJ recommended that we reject the method proposed by Duquesne to phase-in direct retail access. Specifically, Duquesne proposed to phase-in direct retail access in three equal increments of one third of the peak load of each customer class annually starting January 1, 1999, so that all customers will be eligible for direct retail access by January 1, 2001. The ALJ recommended that Duquesne be directed to conduct an open enrollment period beginning July 1, 1998, for all customer classes except small business customers on a "first come, first served" basis.

For the business customers, the ALJ recommended adoption of the OSBA's proposal that to create two classes for customers receiving service through the creation of Small Rate GS/GM and "Large Rate GS/GM". This, the ALJ reasoned, would prevent small account customers from being under represented. The ALJ recommended that the Commission consider the Environmentalists' "Better Choice Plan" when promulgating regulations required by Sections 2807(e)(2) and (3) of the Act.

For the timetable for Phase-in, the ALJ recommended that we reconsider the phase-in schedule for customer choice that we adopted in PECO Energy, and adopt the phase-in schedule proposed by GPU and PECO which begins on January 1, 1999.

For the reasons specified herein, we shall adopt the position of the ALJ to implement; 1) system-wide "first-come, first -served" selection for residential customers as modified below; 2) the OSBA's proposal to split small commercials on a "first-come, first -served" basis; and 3) PECO's pro-rata subscription for industrial and large commercial customers.

We reject the ALJ's recommendation to adopt the positions of Duquesne, GPU and PECO to reconsider the phase-in schedule for customer choice that we adopted in PECO Energy. We shall adopt the same phase-in schedule as adopted in PECO Energy. We find that different phase-in schedules for competition in different parts of the Commonwealth would advantage or disadvantage customers depending upon where they live and through which utility they are served.

III. TRANSMISSION AND DISTRIBUTION RATES - UNBUNDLING ISSUES

A. Introduction

Several interdependent standards of the Act and the Code apply to transmission and distribution (T&D) rates. The Act requires electric utilities to unbundle their "rates and services . . . to allow competitive suppliers to generate and sell electricity directly to consumers in this Commonwealth." (66 Pa. C.S. §2802(14)). Since the T&D components of a utility's rates will continue to be regulated under Chapter 13 of the Code, the rates for these components must be just and reasonable. (PECO Energy, Slip Op., p. 61; See, also, 66 Pa. C.S. §1301).

The process by which the Commission is obligated to unbundle the company's rates into generation, transmission and distribution components is fundamentally a ratemaking process. The Commission must determine the company's cost of service, properly allocate those costs among the generation, transmission and distribution portions of the company's operations, and translate those total costs into individual rates. The Commission is also called upon to set a new rate, known as CTC, based upon expert witness testimony, to recover a just and reasonable portion of the company's uneconomic (or stranded) assets. The CTC is designed to permit the company to recover those stranded costs over a reasonable period of time. These are traditional ratemaking functions as exercised by the Commission since its inception in 1913.

B. 1996 Test Year Cost of Service

1. *Positions of the Parties*

Duquesne used its 1996 cost of service study as the basis for allocating all of its costs between generation, transmission, and distribution. Duquesne submitted that the only disputes to its proposal related to the functionalization of these costs among generation, transmission, and distribution. It claimed the proposals of others move costs out of T&D and into the generation function, thereby reducing the regulated rates paid by the constituents of the intervenors. Duquesne stated that Enron's proposed adjustments were rejected in PECO Energy and further insisted that Enron's alternative cost of service study (Enron Exh. PDR-3) contains circular references and other errors, such as over-allocation of costs to Duquesne's only wholesale customer and omitting revenue from rate class GL. (R.D., p. 46).

Regarding HSS/ARI's request that 50% of Duquesne's past (since 1987) and projected T&D capital expenditures be disallowed, Duquesne asserted that HSS/ARI did not identify a single expenditure that was imprudent. Furthermore, Duquesne argued that HSS/ARI failed to meet their own test: that an intervenor must raise "credible issues" regarding an expenditure to overcome its "presumption of reasonableness." Because Duquesne has not filed a rate case since 1986, HSS/ARI insisted that Duquesne must establish that its T&D capital expenditures since 1986 were just and reasonable to the extent that those costs are subsumed within its current distribution rate structure. (R.D., p. 48).

DII provisionally accepted the Company's 1996 test year Cost of Service, with certain adjustments as discussed below, as the rate unbundling starting point. (R.D., p. 48).

Like HSS/ARI, the PRA found it difficult to accept Duquesne's 1996 cost of services levels since this Commission last approved base rates in 1986; however, the PRA offers no specific criticisms of the test year proposal. (PRA M.B. p. 19; PRA R.B. p. 5). Duquesne used the percentage of labor expenses charged to generation, transmission, and distribution as a proxy method to allocate administrative and general expenses and general plant to these three categories. Enron recommended that the Commission direct Duquesne to conduct a detailed functional cost study and submit it at a later date so distribution rates may be revised accordingly. (Enron M.B. at 12).

Enron further contended that Duquesne's cost of service study inappropriately assigns sales expense, customer information and assistance expense, and uncollectible accounts expense entirely to the distribution function, even though these costs are associated with all aspects of service. Enron claimed Duquesne's attempt to charge 100% of these costs to distribution rates unfairly charges distribution customers for costs for which they are not responsible and also provides an unfair advantage to Duquesne's generation supply activities. Enron asserted that such a cross-subsidy cannot be condoned. (R.D., pp. 52-53).

Enron recommended allocating 100% of sales expense and customer information and assistance expense to the generation function. Under Enron's proposal, uncollectible accounts expense should be allocated to the three functional categories, or, to the extent energy suppliers or third parties other than Duquesne provide billing services and take credit risks, uncollectible accounts expense should be unbundled and removed

from distribution rates. Further, Enron claimed it is 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. (R.D., pp. 54-55).

2. ALJ's Recommendation

Because this Commission denied the same objections of Enron in PECO Energy, Slip Op., p. 59-61, to that utility's proposed allocations for uncollectibles, customer accounts, customer service, and sales, the ALJ reasoned the same treatment should be accorded Duquesne in this proceeding. Furthermore, the ALJ agreed with Duquesne that this Commission should also reject the position of HSS/ARI on this issue. For these reasons, the ALJ recommended that this Commission accept Duquesne's 1996 cost of service study, subject to the adjustments denoted in the Recommended Decision. (R.D., p. 57).

3. Parties' Exceptions

Two parties except to the ALJ's recommendation concerning the 1996 Test Year for Cost of Service. First, HSS/ARI argues the ALJ erred in stating that "HSS/ARI failed to identify even a single expenditure as unreasonable." (R.D., p. 176). HSS/ARI contends Pennsylvania courts have made clear that the burden on an intervenor is merely to establish the existence of a credible issue. The Pennsylvania Commonwealth Court has found that an intervenor challenging a utility's claim which is supported only by the utility's bare assertion "was under no obligation to adduce either evidence or analysis." (University of Pennsylvania v. Pa. PUC, 485 A.2d 1228 (Pa. Cmwlth 1984)). HSS/ARI

argues that it did not bear the burden of showing that Duquesne's expenditures were unreasonable. (HSS/ARI Exc., pp. 6-7).

Second, while recognizing that this Commission rejected a similar proposal by Enron in PECO Energy, Enron requests that we reconsider our decision in PECO Energy and accept Enron's proposal here. Enron contends that by including 100% of sales-related costs in T&D rates, Duquesne will have a competitive advantage and customers of generation suppliers will pay twice -- once in Duquesne's distribution rate and a second time in the rate charged by the supplier. Enron argues this violates Section 2804(6) of the Act, 66 Pa. C.S. §2804(6), which requires that T&D services be provided to all retail customers and generation suppliers on terms comparable to the utility's own use of its system. (Enron Exc., pp. 9-12).

In its Reply Exceptions, Duquesne submits that Enron's argument that certain costs (uncollectibles, customer accounts, customer service, and sales) should be "allocated" to the generation function should be rejected because Enron ignored the functions of how an EDC operates. (Duquesne R.Exc., pp. 18-19).

4. Resolution

Based upon the record before us, we will adopt the ALJ's recommendation to accept the Company's cost of service calculation and reject the HSS/ARI adjustment to remove 1986-1996 distribution plant additions. In addition, we will accept the Company's functionalization and reject the Enron sales expense adjustment, Account 908 adjustment, and uncollectible accounts adjustment.

We note that we denied the same objections of Enron in PECO Energy, Slip Op., p. 59-61, to that utility's proposed allocations for uncollectibles, customer accounts, customer service, and sales. As in PECO Energy, we conclude herein that Enron has not documented sufficiently that a specific portion of the expenses are in fact generation related. The same treatment should be accorded Duquesne in this proceeding. In reaching this result, in PECO Energy, we noted that PECO's T&D rates continued to be subject to Chapter 13 of the Public Utility Code and subject to the Act's rate caps. Parties may challenge existing rates in future proceedings. Further, we noted in the PECO Energy case that as functions continue to be unbundled, a utility's rates may be reexamined to determine if the utility provides for charges which encompass generation or other unbundled services. (Id., p. 61).

We agree with Duquesne that the Commission should reject the position of HSS/ARI on this issue. An intervenor must raise "credible issues" regarding an expenditure in order to overcome the "presumption of reasonableness." (Equitable Gas., supra.). The HSS/ARI have failed to do so. Therefore, the Commission accepts Duquesne's 1996 cost of service study, subject to the adjustments denoted below.

C. Required v. Realized Rate of Return

1. Positions of the Parties

Duquesne proposed establishing T&D rates on a traditional cost-of-service basis, using the traditional three steps. First, Duquesne computed a functionalized revenue requirement for the T&D functions using its authorized rate of return. Second, it allocated the functionalized revenue requirements to customer classes. For distribution, it allocated demand costs to classes on the basis of non-coincident peak demands, and it

allocated customer costs on the basis of the number of customers. For transmission, it allocated costs to classes on the basis of coincident peak demands, which is consistent with the Federal Energy Regulatory Commission (FERC) policy. Third, using these allocated revenue requirements, Duquesne then designed T&D rates for each class. (R.D., p. 58).

Duquesne noted that the several parties objecting to this approach would have T&D rates set on the basis of "realized" (or "earned") rather than "required" rate of return. Duquesne argued that this position must fail because regulated rates are set to recover the required rate of return. Duquesne further contended that no party suggested, much less demonstrated, that the T&D revenue requirements Duquesne proposes are higher than the T&D revenue requirements which this Commission approved in 1987 in Duquesne's last rate case; hence, no basis existed for the claim that the Act is violated. Finally, Duquesne contended that the intervenors' proposals have nothing to do with a concern over shifts between classes; their key objective is to shift costs between functions. (R.D., pp. 58-60).

The OCA posited that Duquesne's use of the full "required" rate of return in developing T&D rates improperly assumes T&D services have been earning a higher rate of return than generating services. The OCA declared that such an approach is inconsistent with establishing the rate cap for "non-generation charges" at the same level which this Commission previously approved for such services. For purposes of unbundling rates, return by function should be determined by applying the same rate of return to all plant. Consequently, the OCA adjusted the Company's T&D rates to reflect the achieved return, rather than the claimed return. The OCA argued that the fact that Duquesne filed rates on this basis in other proceedings does not justify the unbundling of rates on that basis in this proceeding. (R.D., pp. 60-62).

DII argued that use of a "required" rate of return constitutes an inappropriate cost-shift and a violation of the Act's rate cap. (66 Pa. C.S. §§2808(a), 2804(7) & 2804(4)(i)). DII noted that Duquesne requested a rate of return of 9.61%; however, Duquesne's current bundled rates reflect the earned rate of return produced by each rate class as established in Duquesne's last base rate proceeding. DII asserted that the use of required rate of return, rather than earned rate of return, shifts costs between the distribution function and the generation function of the unbundled rates. Although moving class rates of return closer to system average may be appropriate in other contexts, Duquesne asserted that the Act requires that, in order to prevent cost shifting, individual components of distribution rates must be capped at the January 1, 1997 levels until July 2001, or the time when the utility is no longer collecting a CTC, whichever is shorter. (66 Pa. C.S. §2804(4)(i); R.D., pp. 62-63).

DII contended that the Company's use of required rate of return shifts the costs from distribution to generation (or vice versa), either raising or deflating the generation component of the class's rate. DII claimed that this shift violates the Act's mandate that stranded costs be recovered in a manner that does not affect an inter- or intra-class cost shift. (DII M.B., pp. 11-12; 66 Pa. C.S. §2808(a)). DII argued that the purpose of this proceeding is not to set new T&D rates for Duquesne; the purpose is to unbundle existing rates in a manner that does not shift costs or violate the rate caps. (66 Pa. C.S. §§2802(14), 2804(3), 2804(7) & 2808(a); R.D., pp. 63-66).

Enron claimed that Duquesne's proposal amounts to a de facto attempt to secure a rate increase for this portion of its operations. Enron contended that the cost of T&D at Duquesne's "pro forma" or claimed "required" rate of return increases those costs above the level actually incurred in the 1996 test year because the return level

included in Duquesne's study is the level the Company claims it should be earning, not the amount it actually earned. Enron argued that this result contravenes the Act. Enron concurred with DII that Duquesne's proposal shifts costs between customer classes and functions, arguably violating the Act's prohibition against inter-class costs shifts. (66 Pa. C.S. §2808(a)). Enron also urged this Commission to reject Duquesne's proposal. (R.D., pp. 66-68).

2. ALJ's Recommendation

The ALJ agreed with the OCA, DII, and Enron that the Company's use of a "required" rate of return to develop T&D rates constitutes an inappropriate cost-shift and a violation of the Act's rate cap. (66 Pa. C.S. §§2808(a), 2804(7), & 2804(4)(I)). The ALJ also agreed that the purpose of this proceeding is not to set new T&D rates for Duquesne; the purpose is to unbundle existing rates in a manner that does not shift costs or violate the rate caps. (See, 66 Pa. C.S. §§2802(14), 2804(3), 2804(7), & 2808(a)). The ALJ thus recommended that we direct Duquesne to use the "realized" rate of return for each class, as established in its last base rate case, to develop rates. (R.D., pp. 68-69).

3. Parties' Exceptions

In its Exceptions, Duquesne contends that the ALJ's recommendation is in error because there is no possibility of cost-shifting under its proposal. Duquesne maintains that the ALJ's finding that the rate caps prohibit recovery of just and reasonable T&D rates renders the Act confiscatory. Duquesne also contends that its rates for transmission and ancillary services cannot be "set" by this Commission; they are set by the FERC. Duquesne argues that any contrary finding is preempted by federal law. Mississippi Power & Light Co. v Mississippi ex rel. Moore, 487 U.S. 354 (1988). (Duquesne Exc., pp. 33-34).

In their Reply Exceptions, the OCA, the OSBA, the PRA, DII, and Enron argue that Duquesne's Exceptions concerning "required" rate of return are without merit because Duquesne's proposal is inconsistent with the Act's requirements and Duquesne's jurisdictional argument is without merit. The parties submit that Duquesne's proposal to unbundle its rates based on its claimed rate of return for T&D service is inconsistent with the Act's requirement. They note that this Commission established the cap for the non-generation portion of rates at the level that had been approved as of the effective date of the Act. (66 Pa. C.S.§2804(4)(i)(B). Because, the non-generation charges were not specifically separated from generation charges at that date, the parties argue that the only appropriate way to unbundle these services is to assume they were realizing the same actual rate of return at that date and unbundle them accordingly. (OCA R.Exc, pp. 18-19; Enron R.Exc., p.10; PRA R.Exc., p. 7; OSBA R.Exc., pp. 9-10; DII R.Exc., p. 14).

Generally, the parties argue that, as evidenced by PECO Energy, this Commission is fully aware of the jurisdictional lines between T&D rates and that, while it has full authority to establish unbundled distribution rates, transmission rates are exclusively within the FERC's jurisdiction. The parties submit that if FERC awards Duquesne a higher rate of return for transmission rates than the realized rate of return recognized by this Commission, Duquesne's unbundled T&D rate (and unbundled generation rates) will have to be adjusted. Enron submits that such an approach was endorsed by this Commission in PECO Energy and is a necessary approach to fulfilling the Act's mandate. (Enron R.Exc., pp. 10-11; OCA R.Exc., pp. 18-19).

4. Resolution

Based upon our review of the record herein, we adopt the ALJ's disposition which uses realized rather than required returns for setting of the distribution rates. To redesign rates to the required return would disaggregate earnings such that distribution would earn at a different level than generation. Such earnings separations increase stranded cost potential by depressing earnings from generation in order to fund full earnings on T&D from the cap rate levels. In addition, it would require a review of all costs/revenue requirements in T&D.

As stated in the Recommended Decision, the OCA, DII, and Enron argue that the Company's use of "required" rate of return to develop T&D rates constitutes an inappropriate cost-shift and a violation of the Act's rate cap. (66 Pa. C.S. §§2808(a), 2804(7), & 2804(4)(i)). Duquesne is correct that development of "required" rate of return follows traditional rate-making principles; however, the unbundling methodology that we adopt still permits Duquesne the opportunity to earn its authorized rate of return based on the revenue requirements in existing rates. While this is a rate proceeding in which both existing rates are being unbundled and a new rate, the CTC, is being established, neither Duquesne nor any other party introduced evidence or advocated setting new T&D rates from the ground up. Under such circumstances, it would be inappropriate to change rates on a single issue, such as the authorized rate of return. Our approach retains the existing authorized rate of return.

In contrast, Duquesne's approach would establish an increased opportunity to achieve the authorized rate of return on T&D while essentially reducing the authorized rate of return of generation. The Recommended Decision correctly holds that, on day one after implementation of new rates as approved by this Commission, a utility begins earning

"realized" or "earned" rate of return and not "required" rate of return. We are reminded that ratemaking provides an opportunity to earn a fair rate of return, not a guarantee of its realization. If Duquesne is not now achieving its required rate of return, Duquesne will continue to have the opportunity to achieve it, given unbundling of the rates.

D. Distribution Losses

1. Positions of the Parties

Compensation is embedded in current bundled rates for electricity losses (distribution losses) experienced as electricity moves along distribution lines. This additional compensation represents the cost of extra generation required to replace the distribution losses. Duquesne asserted that no dispute any longer exists regarding this issue. Duquesne initially included the costs associated with distribution losses in its T&D rates. Duquesne agreed to "unbundle" losses so customers can procure them from alternate suppliers. According to Duquesne, a portion of the embedded costs allocated to losses will consequently become potentially stranded and, hence, must be included in the CTC. The OCA agreed that stranded costs associated with distribution losses should be included in the CTC. (R.D., pp. 69-70).

Only the PRA and Enron seemed to disagree that the issue of distribution losses appears to be settled. Both, however, urged this Commission to require distribution losses to be removed from Duquesne's distribution rates, so alternative suppliers may bid competitively for such losses. (R.D., p. 70).

2. ALJ's Recommendation

The ALJ found that, since Duquesne has already agreed to remove distribution losses from its distribution rates (so that alternative suppliers may bid competitively for such losses), a perceptible issue no longer exists. For this reason, he recommended that this Commission accept Duquesne's proposal to allow customers to procure distribution losses from alternate suppliers. To the extent that a portion of the embedded costs allocated to distribution losses will become potentially stranded, he also recommended that they be included in the CTC. (R.D., p. 70).

3. Parties' Exceptions

In its Exceptions, the OCA wishes to make clear that its calculation of stranded cost already has been increased to include line losses. The OCA asserts that its proposed CTC calculation requires no additional modification to reflect treatment of distribution line losses as costs functionalized to generation costs. Regarding Duquesne's assertion that a portion of distribution line losses will be potentially stranded as a result of shifting costs in order to unbundle distribution line losses, the OCA emphasizes that Duquesne included the capacity costs associated with providing line losses in T&D rates based upon estimated market prices for providing line loss service. The OCA asserts that there is, thus, no basis to assume that there will be additional stranded costs as a result of moving line losses back to the generation function. (OCA Exc., pp. 19-20).

Enron argues that the ALJ erred because these costs do not meet the definition of stranded costs, which include only those costs recoverable in a regulated environment but which may not be recoverable in a competitive environment. (66 Pa. C.S. §2803). Enron contends that since all companies in the competitive market will be

required to procure energy, including distribution line losses, the cost of those losses is a cost that can be and will be recovered in the competitive market -- the opposite of the standard required by the statute. (Enron Exc., pp. 13-14).

In its Reply to Enron's Exceptions, Duquesne argues that distribution losses are one of the very functions that will be subject to competition, thereby giving rise to stranded costs. The resulting stranded costs should be recoverable in the same manner as all other generation-related stranded costs. (Duquesne R.Exc., p. 19).

4. Resolution

Duquesne has already agreed to remove distribution losses from its distribution rates. Therefore, we will accept the ALJ's recommendation that customers be allowed to procure distribution losses from alternate suppliers. With regard to the OCA's exception that its calculation of stranded costs already has been increased to reflect line losses, we would note that, to the extent that a portion of embedded costs allocated to distribution losses will become potentially stranded, such costs may be recoverable through the CTC, if appropriate, based on the determination of stranded utility generation.

E. Ancillary Services

1. Positions of the Parties

Ancillary services include scheduling, dispatch and control service, energy imbalance service, reactive power and voltage control service, regulation and frequency control service, operating reserves-spinning, and operating reserves-supplemental. While generating units provide a number of these services, Duquesne made adjustments to

functionalize as transmission costs $4,021,675 for reactive power, $5,187,040 for regulation and frequency control, and $8,913,265 for operating spinning reserve, for a total of $18,121,980. (R.D., pp. 70-71).

With the exception of scheduling services, Duquesne explained that all ancillary services are provided by generating units and each is "necessary to maintain the integrity of the transmission system" in an open access regime. In its Order No. 888, the FERC ruled that all public utilities must offer these services to direct access customers at regulated rates. The FERC also distinguished between services that can only be offered by the host public utility and others that can be competitively procured, assuming that prevailing regional reliability rules permit it. (FERC Order No. 888, p. 31, 715-716; Duquesne St. 7, p. 13-14). Duquesne contended that it has complied with FERC Order No. 888 by filing cost-based ancillary services rates with the FERC. (Duquesne M.B. at 15; Duquesne Light, FERC Docket No. OA96-56-000). (R.D., p. 71).

The first question is whether Duquesne should allow its customers to procure all these services from alternative suppliers. Duquesne submitted the FERC has determined which services Duquesne must provide and which services can, consistent with regional rules, be supplied by others. (FERC Order No. 888, p. 31,715-716; Duquesne St. 7, p. 13-14). The second question is whether, for ratemaking purposes, these services should be treated like T&D, and thereby purchased from Duquesne at regulated rates, or treated like generation, and thereby competitively procured in the market, with the stranded portion being recovered through the CTC. (R.D., p. 72).

The OCA disagreed with Duquesne's proposed adjustment to shift the cost of ancillary services from generation to transmission. Since these costs are associated with generating units, the OCA removed the Company's adjustment which transferred

these costs from the generation function to the T&D functions. The OCA showed T&D costs of $285,417,000 before Duquesne's adjustments for ancillary services. (R.D., pp. 73-74).

DII argued that inclusion of generation-related ancillary services in the Company's unbundled transmission rates is inappropriate because it shifted costs between functional categories. Generation-related ancillary services costs are not included in Duquesne's current transmission rates. Consequently, DII claimed these costs cannot properly be assigned to the transmission function in unbundling Duquesne's rates. To prevent inappropriate double payment, DII recommended moving $18 million of ancillary services costs from the transmission rates into the market price component of unbundled generation rates. (R.D., pp. 74-75).

The Company agreed that generation-related ancillary services which can be competitively supplied should be removed from the transmission rate. (Tr., pp. 720-721). Because all generation-related ancillary services are not currently subject to competition, the Company's adjustment resulted in only a partial removal of ancillary services costs from the transmission rate. DII contended that all generation-related ancillary services be removed from the transmission rate and that the Company may charge customers for any generation-related ancillary service not competitively procured. If its adjustments are not accepted, DII argued that either ratepayers must receive a credit toward stranded costs for those services or Duquesne's market price forecast and stranded cost calculation should be adjusted to reflect the Company's ability to receive greater compensation for these services (at embedded costs as opposed to market price). (R.D., pp. 76-77).

The PRA agreed with the assessment of the OCA and DII concerning Duquesne's proposal for the costs of ancillary services but concurred with the treatment DII proffers on this issue. (R.D., p. 78).

Enron disagreed that the appropriate mechanism is through an end-of-the-year "market based" credit. Rather, Enron suggested the transmission-related portion of the rate should be unbundled to recognize the delivery of those services by an alternative supplier. Enron would base the credit upon the embedded cost of the ancillary service as established by Duquesne's cost of service study. Enron urged the Commission to direct Duquesne to calculate the embedded generation cost of ancillary services; this value should then be deducted from the Company's generation revenue requirement. In addition, Enron agreed with MAPSA's arguments on imbalance charges and scheduling charges. (R.D., pp. 78-79).

MAPSA asserted that Duquesne's proposal includes the partial unbundling of ancillary services and allows for competitive provision of only one of them. Duquesne initially proposed to unbundle the ancillary service of supplemental reserves and subsequently modified its proposal to provide for a "market-based" credit for those services that can be purchased from an entity other than Duquesne (currently only supplemental reserves) and to add that credit to its customer generation credit (CGC). (Duquesne St. 5R, p. 2.) MAPSA submitted that Duquesne should be required to unbundle all ancillary services and provide a separate, fully-allocated credit for each of those services, which should be added to the CGC to compensate customers if they choose to have these services competitively provided. (R.D., pp. 79-80).

Regarding charges for imbalances, Duquesne proposed to charge each supplier for imbalances that fall outside of a 1.5% "dead-band" during off-peak periods at

the higher of 110% of Duquesne's out of pocket costs, or $50/mWh, and during on-peak periods, the higher of 110% of Duquesne's out of pocket costs or $100/mWh. Duquesne will provide class-average load data for customers with specific meter types to suppliers, who will then have to match the load shape. Suppliers are penalized if the supply does not match the usage but not if the supply does not match the load data. In actually scheduling the load, suppliers will be forced to rely on load data which Duquesne provides and which MAPSA alleged is likely to be highly inaccurate for any particular supplier. When the data on which a supplier must rely is not accurate, MAPSA argued the penalties should be adjusted or eliminated because of the potential for abuse. (R.D., pp. 80-81).

MAPSA proffered that a reasonable charge should be 100% of Duquesne's out-of-pocket expenses and that this Commission should allow imbalances to be traded among competitive suppliers. MAPSA also suggested that this Commission allow imbalances to be resolved in-kind, at a time, and in a manner agreed upon by Duquesne and the suppliers. (R.D., p. 81).

Duquesne proposed to charge suppliers $100 for each schedule and each change in schedule which is submitted to Duquesne. MAPSA noted that the Company derives the fee by dividing the adjusted labor expense by the number of hours in a year, which MAPSA contended merely yields a result establishing the hourly cost of scheduling and not the actual transaction cost. MAPSA argued the fee is so high it is likely to hinder the development of a robust competitive market. When utilities impose charges which are anti-competitive, MAPSA argued that those charges must be proved to be necessary and not speculative and must be specifically quantified. Where a utility fails to meet its burden of providing substantial evidence, its proposed rate must be denied in its entirety. (Lower Frederick Township Water Company v. Pa. PUC, 409 A.2d 505, 507

Pa Commonwealth Ct.(1980) (affirming this Commission's denial of all elements of a proposed rate increase where the utility did not meet its burden of proof)). (R.D., pp. 82-83).

2. ALJ's Recommendation

The ALJ initially found that Duquesne admitted that generating units provide the ancillary services and the costs associated with the challenged adjustments to transmission were estimated as portions of the revenue requirement associated with generating units estimated to be required to provide these services. Therefore, the ALJ reasoned, it follows that the costs of ancillary services should be attributed to the generation function if the particular service can be competitively procured, and any stranded costs associated therewith should be recovered in the CTC. The ALJ also noted that FERC Order No. 888 will require the unbundling of ancillary services consistent with applicable reliability council requirements. In the absence of such unbundling and the competitive availability of ancillary services, FERC Order No. 888 requires that all public utilities must offer these services to direct access customers at regulated rates.

Finding that it is not at all clear that the East Central Reliability Coordination Agreement (ECAR) imposes significant restrictions on the competitive procurement of these services, the ALJ recommended that the following amounts be removed from T&D rates and moved into generation costs: $4,021,675 for reactive power, $5,187,040 for regulation and frequency control, and $8,913,265 for operating spinning reserve, for a total of $18,121,980. Further, the ALJ recommended that this Commission disallow Duquesne's proposed imbalance charges and the $100 scheduling charge, since the Company did not provide sufficient evidence to justify them and for the reasons MAPSA espoused. (R.D., pp. 83-84).

3. Parties' Exceptions

Duquesne takes exception to the ALJ's recommendations on the basis that the Commission is preempted by federal law. (R.D., p. 84). Regarding the ALJ's finding that Duquesne had not proven that ECAR rules require that certain ancillary services be provided by the control area, Duquesne argues that any question of how it applies these rules must be addressed through the complaint procedures available under its open access tariff or Section 206 of the Federal Power Act. Duquesne contends that the finding was in error because of confusion regarding whether ECAR rules prohibit unbundling of rates; Duquesne alleges they do not and that unbundling is actually required by FERC Order No. 888. Duquesne alleges further confusion over whether ECAR rules prohibit the provision of services by generators located outside the control area; Duquesne alleges they do and that such services are also within FERC's authority. Duquesne also argues that its proposed energy imbalance charge is under FERC jurisdiction. (Duquesne Exc., pp. 34-35).

The OCA's exceptions regarding ancillary services are combined with its exceptions regarding distribution line losses and have been discussed supra.

Two parties replied to Duquesne's exception disputing the Company's assertion that the only forum before which parties may question the rates charged to retail consumers for these services is the FERC. The DII and MAPSA note that the issue concerning ancillary services is that generation costs should properly be included in generation rates. They argue that the Company's exception should be denied. (DII R.Exc., 14-15; MAPSA R.Exc., pp. -5).

4. Resolution

As the Recommended Decision correctly states, a traditional rate making principle is that assignment of costs follows function. Since Duquesne admits that its generating units can provide the ancillary services, (Duquesne M.B., p. 15), and the costs associated with the challenged adjustments to transmission services were estimated as portions of the revenue requirement associated with generating units estimated to be required to provide these services, (OCA St. 4, p. 4), then it naturally follows that the costs of ancillary services should be attributed to the generation function if the particular service can be competitively procured, and any stranded costs associated therewith should be recovered in the CTC. Duquesne and the intervenors apparently agree on this general principle.

With respect to ancillary services, the question is which ancillary services can be competitively procured. FERC Order No. 888 holds that all public utilities must offer ancillary services to direct access customers at regulated rates. Yet, the FERC also distinguishes between services that can only be offered by the host public utility and others that can be competitively procured, assuming that regional reliability rules permit it. Duquesne contends that its regional reliability council, ECAR, imposes significant restrictions on when many of these ancillary services can be competitively procured. (Duquesne St. 7, pp. 13-14; Duquesne St. 5R, p. 19). Duquesne's witness admitted this may not be the case, thereby undermining Duquesne's point. (Tr., p. 772).

We agree with most of the parties that ancillary services should be available for competitive procurement, but the fact remains that they are FERC-jurisdictional and all are now included in the FERC-approved open access tariff. Transmission services are FERC jurisdictional and, as such, the terms and conditions under which unbundled

transmission services are to be provided to customers will be controlled by the FERC-approved Open Access Tariff for the transmission services procured by either Duquesne or a competitive supplier, as the case may be, on behalf of end-use customers, or procured directly by qualifying large customers. It would be both difficult and inappropriate to unbundle such rates and services at this time without FERC participation. Unbundling these services must await a future date. Accordingly, Duquesne's Compliance filing need not contain any unbundled retail end-use transmission rates. The terms and conditions for transmission services for each separate rate classification are those established by FERC.

Additionally, consistent with the ALJ's recommendation, we will disallow Duquesne's proposed imbalance charges and the imbalance trading standard (see additional discussion concerning imbalance charges, infra) and the $100 charged to suppliers for scheduling changes, since the Company has not provided sufficient evidence to justify them. In addition, as noted by MAPSA, Duquesne's proposal includes the partial unbundling of ancillary services by providing a "market-based" credit. Based upon the record before us, we find, however, Enron's proposal that the "market based" credit should be based on the embedded cost of the ancillary services established in Duquesne's cost of service study to be reasonable and in the public interest.

We find that in the unbundling of an existing rate, use of a "market-based" credit is inappropriate. Only embedded rates are considered in the unbundling process. As such time as FERC and/or ECAR permits the unbundling of any ancillary service, a credit for the embedded cost of that service, as determined by the FERC open-access tariff, will be provided to a customer obtaining that ancillary service competitively.

We direct Duquesne to include a specific Supplier Tariff as part of its compliance filing. The Supplier Tariff must reflect all applicable FERC and ECAR rules while supplementing those rules to reflect all aspects of the interaction between Duquesne and an EGS necessary and appropriate for the efficient implementation of retail direct access. The Supplier Tariff is not a services agreement; it is a set of rules and procedures. It should include no fees or other charges except as have been approved by FERC or this Commission upon documentation of net incremental cost. The Supplier Tariff must address customer sign-up and switching, balancing, billing, and data exchange. The compliance filing Supplier Tariff shall be consistent with this Opinion and Order and all other relevant Commission regulations and Orders that have been adopted to date concerning relevant issues, procedures, and protocols.

F. Voltage-Differentiated Rates

1. Positions of the Parties

Enron proposed a Distribution Services Tariff (DST) which, it claimed, will apply to suppliers who will be acting as agent for individual or aggregated end-user customers. In conjunction with the DST, Enron proposed that applicable rates be designed so as to reflect the characteristics of a customer's service, including voltage level, rather than historical identification by traditional "class" of service. Enron suggests 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. (R.D., pp. 85-87).

Both Duquesne and DII argued that Enron's proposal should be rejected because Enron did not sufficiently demonstrate that implementation of its voltage differentiated rates will not shift costs between classes. (R.D., pp. 85-87).

2. ALJ's Recommendation

The ALJ agreed with Duquesne and DII on this issue and recommended that this Commission reject Enron's proposal. The ALJ reasoned that the Act prohibits cost shifting in the unbundling process and mandates a rate cap on non-generation rates through mid-2001. (See, 66 Pa. C.S. §§2804(4)(i) & 2804(7)). The ALJ concluded that the fact that the cost shifting may affect the supplier, who is the "agent" for the end-user customer, is irrelevant. (R.D., pp. 87-88).

3. Parties' Exceptions

Enron argues the ALJ erred in determining that Enron's proposed DST could cause cost-shifting or rates that exceed the rate cap. Provisions in the Act concerning cost-shifting and rate caps apply only to the EDC. Since, under the proposed delivery tariff, the supplier would be paying the EDC's rates, Enron contends there can be no cost shifting or rate-cap excess, in the aggregate, because competitive forces mandate that rates charged by an EGS to end-users are not going to be in excess of the EDC's rate cap. Duquesne's position, Enron argues, obscures the real dispute, which is how far and how fast the Commission should go in unbundling distribution services and rates. (Enron Exc., pp. 15-16). As an alternative to its DST, Enron argues that this Commission should advance the development of such a tariff by ordering Duquesne to work with interested suppliers and customer groups to develop a voltage differential DST for future application. (Id., p. 16).

In their replies to Enron's exception, DII and Duquesne argue that Enron has not sufficiently addressed the potential for cost shifting under its proposal. (DII R.Exc., p. 19; Duquesne R.Exc., p. 19).

4. Resolution

We accept the ALJ's recommendation to reject the Enron voltage-differentiated rates proposal. We agree with the ALJ that insufficient evidence has been presented by Enron to demonstrate that Enron's voltage-differentiated rates will not violate the Act's prohibition against cost-shifting or exceed the rate cap on non-generation rates.

G. Other Issues

1. Distribution - Related Capital Expenditures

(a) Positions of the Parties

HSS/ARI claimed that, with respect to distribution-related capital expenditures, the Duquesne Exhibit DJC-3, pp. 22 & 28, reveals that, between the years 1997 and 2005, Duquesne will have to make capital additions of $532 million to provide a cost basis that will allow it to back-in to its proposed 11.5% return on equity. HSS/ARI argued that Duquesne's projections of distribution-related capital expenditures appear to be designed to help Duquesne maintain its substantial financial achievements for its shareholders, with no commensurate benefit for its ratepayers.

HSS/ARI pointed out that Duquesne has a history, dating back to 1987, of forecasting distribution-related capital additions of approximately 10% more than actual

expenditures. HSS/ARI cited the holding in PECO Energy for the proposition that the Commission should disallow 10% of Duquesne's projected distribution-related capital additions because the Company has a history of over-budgeting future capital improvements.

(b) ALJ's Recommendation

The ALJ found that Section 2808(c)(4) of the Act, 66 Pa. C.S. §2808(c)(4), imposes a duty upon every electric utility, during the transition period, to mitigate generation-related transition or stranded costs to the extent practicable. These efforts may include minimization of new capital spending for existing rate base generation assets. (66 Pa. C.S. §2808(c)(4)(ii)). Giving affect to these provisions, the Commission in PECO Energy, Slip Op., pp. 81-82, disallowed 5% of the budgeted capital additions to generating plant because PECO had a ten-year history of over-budgeting future capital improvements and the Commission determined permitting full recovery would constitute an anti-competitive subsidy of PECO's future competitiveness in the generation market. The ALJ recommended that this Commission deny this proposal of HSS/ARI. (R.D., p. 91).

(c) Parties' Exceptions

No party excepted to the ALJ's recommendation

(d) Resolution

The Act does not compel the result advocated by HSS/ARI. HSS/ARI has not documented that existing rates are unreasonable. HSS/ARI overlook the fact that T&D

rates will still remain regulated after implementation of this restructuring plan. If HSS/ARI believe T&D rates are still unreasonable at that time, HSS/ARI can challenge those rates in a future proceeding before this Commission. We shall adopt the ALJ's recommendation to reject the HSS/ARI proposal.

2. Targeted Area Planning

(a) Positions of the Parties

The Environmentalists propose that this Commission require Duquesne to use "Targeted Area Planning" for T&D system improvements. (Env. M.B., pp. 11-12). As load grows, the Environmentalists posited that EDCs will come under increasing pressure to upgrade transmission and distribution lines. The Environmentalists recommend an "integrated" approach to distribution system planning that encourages the utility to identify and implement the least-cost option in meeting system requirements by finding the least expensive solution to distribution system needs or problems. (Env. St. 1, pp. 16-18). The Environmentalists suggest targeting demand-side management approaches or citing generation in local areas to reduce or avoid the need for distribution system upgrades.

(b) ALJ's Recommendation

The ALJ noted that the Commission already requires jurisdictional electric utilities to file annual integrated resource plans. Presumably, this practice will continue for that portion of the electric utility industry still regulated by this Commission after implementation of direct access to the electric generation market, i.e., T&D. For

purposes of this proceeding, the ALJ recommended that this Commission need undertake no further action on the Environmentalists' proposal. (R.D., p. 93).

(c) Parties' Exceptions

The Environmentalists renew their arguments in their Exceptions. In its reply to the Environmentalists exceptions, DII argues that the ALJ's recommendation should be adopted because these issues are better addressed through specific legislation or a generic proceeding before the Commission. DII submits that uniform environmental requirements may hinder the development of a robust competitive environment. (DII R.Exc., p. 20).

(d) Resolution

The Environmentalists proposed that Duquesne be directed to collect data now to facilitate "Target Area Planning," incorporating integrated resource planning principles for planning transmission and distribution system upgrades. The Environmentalists argue that regulated distribution service should be provided at the lowest cost to provide reasonable service. If the least-cost strategy to provide reasonable distribution service is to reduce load through conservation or through strategic location of distributed power, then such approaches are preferable to new construction.

The Environmentalists have made several good suggestions, however, it is not appropriate to adopt any specific requirements in this proceeding, The Environmentalists state in Exceptions that all they sought "in raising this issue is a clear statement by the Commission putting the EDC on notice that a least cost-planning approach is expected." To that extent, the Environmentalists Exception is granted: distribution

service is to be planned with such principles in mind. The Environmentalists and other parties are encouraged to pursue such issues in other Commission proceedings such as those concerning resource planning, reliability, and maintaining the transmission and distribution system.

H. Summary and Conclusion

The ALJ recommended that Duquesne's proposal to use its 1996 cost of service study as the basis for allocating all of its costs between generation, transmission, and distribution subject to the adjustments denoted in the Recommended Decision. The ALJ recommended rejection of Duquesne's proposal to use a "required' rate of return to develop T&D rates, and recommended that we direct Duquesne to use the "realized" rate of return for each class, as established in its last base rate proceeding to develop T&D rates.

The ALJ recommended that we accept Duquesne's proposal to allow customers to procure distribution losses from alternate suppliers, and that embedded costs allocated to distribution losses be included in the CTC, to the extent that they will potentially become stranded. The ALJ found that the costs of ancillary services should be attributed to the generation function if the particular service can be procured, and any stranded costs associated therewith should be recovered in the CTC. With regard to voltage-differentiated rates, the ALJ recommended that we reject Enron's proposed Distribution Services tariff which it claimed would apply to suppliers who will be acting as an agent for individual or aggregated end user customers.

The ALJ recommended that we reject the proposal of HSS/ARI to disallow 10% of Duquesne's projected distribution related capital additions, based upon the

argument of HSS/ARI that Duquesne has a history of over-budgeting future capital improvements. Reasoning that the Commission already requires jurisdictional electric companies to file annual integrated resource plans, the ALJ concluded that for purposes of this proceeding, there was no need act upon the Environmentalists' proposal to use Targeted Area Planning for T&D system improvements.

For the reasons specified herein, we shall adopt the ALJ's recommendation to adopt Duquesne's proposal to use its 1996 cost of service study as the basis for allocating all of its costs between generation, transmission, and distribution subject to the adjustments denoted in the Recommended Decision.

We shall also reject the Enron-proposed sales expense adjustment. We will adopt the ALJ's proposal to use "realized" rather than "required" rates of return for setting of distribution rates.

Noting, as did the ALJ, that Duquesne has already agreed to remove its distribution losses from its distribution rates, we will adopt the ALJ's recommendation to procure distribution losses from alternate suppliers. Additionally, we find that to the extent that a portion of embedded costs allocated to distribution losses will become potentially stranded may become recoverable through the CTC, if appropriate, based on the determination of stranded utility generation.

We will adopt the ALJ's recommendation to attribute the costs of ancillary services to the generation function if the particular service can be competitively procured, and that any stranded costs therewith should be recovered in the CTC. We also direct Duquesne to include a specific Supplier Tariff, which reflects all applicable FERC and ECAR rules, as part of its compliance filing.

We agree with the ALJ's recommendation to reject Enron's proposed voltage-differentiated rates proposal, because Enron failed to demonstrate that the proposed voltage-differentiated rates would not violate the Act's prohibition against cost shifting.

We will adopt the ALJ's recommendation to reject HSS/ARI's proposal to disallow 10% of Duquesne's projected distribution-related capital additions. We find that the proposal overlooks the fact that T&D rates will remain regulated, and any party can challenge those rates in a future proceeding before us.

We adopt the ALJ's recommendation to take no further action on the Environmentalists' proposal regarding Target Area Planning since there is already a requirement for jurisdictional electric utilities to file annual integrated resource plans.

IV. TRANSITION OR STRANDED COSTS

A. Overview of Stranded Cost Valuation Approaches

1. Statutory Directives Concerning the Identification and Recoverability of Stranded Costs

Pursuant to Sections 2808(a) and 2804(13) of the Act, 66 Pa. C.S. §§2808(a) & 2804(13), electric companies are provided the opportunity to recover transition or stranded costs, as defined in the Act, through a CTC assessed upon every customer accessing the electric company's T&D network. The Act defines "transition or stranded costs" as:

> An electric utility's known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market and which the [C]ommission determines will remain following mitigation by the electric utility.

In accordance with the Act, the term "transition or stranded costs" includes: (i) regulatory assets and other deferred charges typically recoverable under current regulatory practice, the unfunded portion of the utility's projected nuclear generating plant decommissioning costs and cost obligations under contracts with non-utility generating ("NUG") projects which have received a Commission Order, the recoverability of which is to be determined pursuant to 66 Pa. C.S. §2808(c)(1); (ii) prudently incurred costs related to cancellation, buyout, buydown or renegotiation of NUG projects, subject to statutory conditions, the recoverability of which is to be determined pursuant to 66 Pa. C.S. §2808(c)(2); and (iii) net plant investments and costs attributable to the utility's existing generation plants and facilities, and certain other

enumerated costs, the recoverability of which is to be determined pursuant to 66 Pa. C.S. §2808(c)(3).

2. Positions of the Parties

Duquesne proposed, in the event no merger with APS is consummated, to offer an immediate divestiture of its generating assets to determine the value of its stranded assets. (R.D., p. 159).

Duquesne noted that the pivotal issue in this proceeding is whether this Commission should accept its offer to auction its generating assets today. Duquesne stated, that if its offer is accepted, it should resolve most disputes regarding the quantification of stranded costs and the methodology for recovering them. If that offer is not accepted, Duquesne argued that the Commission must choose between sharply different market valuation and stranded cost recovery proposals.

In its direct case, Duquesne claimed regulatory assets and decommissioning expenses under Section 2808(c)(1) of the Act. Duquesne noted that it has no NUG project exposure. As a result, stranded costs under Section 2808(c)(2) are not an issue. With respect to its generation plant-related stranded costs under Section 2808(c)(3), Duquesne proposed, in its direct case, a market-based valuation approach which will defer until 2003 a final valuation of its generation plant-related stranded costs as of December 31, 2005. The Company contended that, by that time, a competitive generation market will likely have developed so as to permit a stranded cost determination based upon actual market data. According to Duquesne, only a market-based determination of stranded costs can reasonably satisfy the "known and measurable" criteria set forth in the Act. (R.D., p. 95)..

Duquesne proposed this final market valuation in 2003 to be calculated by a three-member arbitration panel using objective market data such as forward contracts, future contracts, and/or comparable generating unit asset sales. Until the final valuation occurs, Duquesne proposed to set annual CTCs on the basis of an annual Request For Proposal (RFP) to sell a substantial block of power for a one-year term. Duquesne asserted that customer-specific CTCs will be set using the market prices established by the RFP, information about each customer's consumption and information on class load shapes.

Duquesne asserted that the CTC, based on these annual RFPs, will collect a pool of money that will be compared to the book value of generation-related assets (net of amortization) as of December 31, 2005, in the final valuation process. In the final valuation, the panel will recommend a CTC that will recover any remaining level of stranded costs. If no stranded costs associated with generating plants exist at that time, there will be no CTC. If stranded costs are projected to extend beyond 2005, given Duquesne's rate cap under Section 2804(4) of the Act , Duquesne will propose to extend the rate cap beyond 2005. (R.D., p. 96).

Since it posited that a final stranded cost valuation should be deferred until 2003, the Company did not propose a one-time administrative valuation of generation plant-related stranded costs in its direct case. However, in rebuttal, in response to the OCA's and DII's contentions that its market valuation proposal is deficient because it does not include a one-time quantification of stranded costs as of January 1, 1999, Duquesne presented evidence intended to support a total stranded cost determination of $1,916 million, including regulatory assets of $374.45 million.. The stranded generation plant component of the $1,916 million is $1,542 million, including a first-time claim of

approximately $208 million, relating purportedly to unavoidable sunk costs incurred regardless of whether plants are operating (PV of Costs Independent of Operation), and approximately $41 million claimed as M&S and Fuel-Related Sunk Costs. (R.D., p. 99).

Duquesne rejoined that it is willing to advance the date for the optional asset auction. Instead of the 2003 date for the auction referenced in rebuttal, the Company will, in its stand-alone restructuring case, agree to an immediate auction, if this Commission determines that it cannot accept Duquesne's auction offer due to the delay. Duquesne, however, reserved the right to submit a proposal for addressing its continuing obligation to serve under the rate cap if and when the Commission orders an immediate auction. Duquesne posited that the fundamental premise of its approach to stranded cost recovery is that the market, not career forecasters, should set the value of its generating assets. The Company claimed that no party presented a compelling argument to rebut this premise, and indeed, most parties agreed with it. (R.D., p. 100).

Duquesne suggested that the principal dispute is not over the premise that administrative "forecasts" are inherently unreliable. Duquesne asserted that, the disputes center on the market valuation method and the timing of that valuation. In contrast, the essential criticism of Duquesne's initial plan was that an auction of generation is the best and whatever valuation method is used, it must be employed today, not in 2001-2003 (as proposed by Duquesne). Duquesne urged the Commission to "resolve" the matter by finding that an auction provides the best valuation method. Duquesne submitted that any necessary findings regarding competing valuation methods presented in the merger case should be made in that case, not here. (R.D., p. 105).

If its auction offer is accepted, Duquesne claimed that three main implementation issues must be addressed:

1. The process and rules by which the auction is conducted. Duquesne commits to file proposed procedures and rules within 90 days of the date of entry of a Commission Order accepting its auction proposal.

2. The establishment of an "interim" CTC to take effect January 1, 1999 applying the same rates (and credits) approved in the pilot program for customers electing direct access during this interim period.

3. The method for calculating a "permanent" CTC using market values produced by the auction[13].

The OTS did not oppose Duquesne's divestiture option, which Duquesne agreed in rebuttal and rejoinder testimony to submit to this Commission. Likewise, the OTS did not oppose the Company's claim for regulatory assets, with the exception of deferred caretaker costs and decommissioning, infra. The OTS supported, with two modifications, the Company's direct case proposal to defer a final valuation of generation plant-related stranded costs until 2003, and to base the valuation on objective market data in 2003 rather than today's projections. The OTS opined that the market value approach is superior to a "regulator-administered approach," which would be involved in the one-time administrative quantification of stranded costs as of January 1, 1999, sought by DII and the OCA.

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[13] If an immediate divestiture occurs, Duquesne proposed to "waive" application of Section 2804(4)v and adopt the general approach used in PECO Energy, provided the following two conditions are met. First, Duquesne be permitted to fully recover (e.g. with no "sharing" and a compensatory return on equity) its stranded costs, as established by the market values produced by the auction. Second, Duquesne's continuing obligation to serve at capped rates be addressed. Duquesne commits to submit a proposal to address its continuing obligation to serve at the same time it files a final CTC calculation, using market values produced by the auction. (R.D., p. 104).

The OTS proposed two modifications to Duquesne's deferred valuation proposal. First, the OTS proposed that the rate cap under Section 2804(4) and the CTC collection period be extended if the final valuation in 2003 results in a stranded cost level which will produce CTC "rate shock." The OTS' second modification concerned the Company's ROE spill-over proposal. Duquesne posited that 11.5% is a reasonable rate of return on equity and linked its "ROE spill-over" trigger to 11.5% in earnings. its earnings exceeded 12%. The OTS asserted that a reasonable rate of return on equity for Duquesne is 10.50%. Consequently, the OTS recommended that 10.50% be used for the "ROE spill-over" trigger.

The OCA opposed Duquesne's final valuation and rate cap/ROE spill-over proposals and submitted that this Commission should reject them in favor of a one-time determination of stranded costs in this proceeding. The OCA asserted that a sharing of stranded costs by amortizing stranded costs over a seven-year period, without allowing a return on the unamortized balance of the Company-owned generating assets should be approved by the Commission. The OCA argued that Duquesne's proposals should be rejected because they are inconsistent with the Act, provide no near-term rate relief to consumers, are administratively burdensome, will interfere with the competitive market, will interfere with the Company's incentive to mitigate stranded costs, and will require customers to bear the entire stranded cost burden of the significant amount of uneconomic excess capacity currently held by the Company. The OCA emphasized that the 11.5% ROE is far too high and that it will be practically impossible to determine earnings as part of its ROE spill-over proposal when the Company has "one foot in the competitive market."

The OCA claimed that the Company's argument that the Act requires this Commission to determine the "known and measurable" level of stranded costs, and that such a determination cannot be made in this proceeding, is simply wrong, and suggests the Commission's PECO Energy decision contravenes the law. The OCA explained, while performing market valuations on long-lived plants is a difficult undertaking, the same will be true in 2003, when Duquesne proposes that such a valuation be made. The OCA noted that, in PECO Energy, this Commission found PECO's stranded cost determination was known and measurable. (R.D., p.112).

The OCA also averred that Duquesne misinterpreted Section 2804(4)(v) of the Act, by allowing the Company to maintain its rates at the level in effect at the effective date of the Act. The OCA submitted that the Legislative Intent of this Section, which is included in the rate cap provisions of the Act, was to preempt complaints against current rates after a company's restructuring had been completed, not to prevent rates from being lowered in a company's restructuring case.

The OCA further argued that it is inappropriate to assume the uncertainty in estimating stranded costs will be dispelled over the next several years or that an "unbiased" arbitration panel will be able to reach a better valuation of stranded costs. The OCA suggested that the interim establishment of the market price through an auction process may result in a depressed market price proxy, leading to overstated CTC charges at ratepayers' expense and to Duquesne's benefit. The OCA further argued that Duquesne's proposal eliminates the possibility of any rate savings for customers during the CTC recovery period. The OCA contended that this is extremely problematic given Duquesne's very high rates and its own recognition that rates during this period will exceed its standard cost of service by a substantial amount. The OCA interjected that a final valuation in 2003 will weaken Duquesne's incentives to mitigate stranded costs and maximize asset value of stranded costs.

The OCA contended that Duquesne's entire approach to valuation and recovery of stranded costs is fraught with problems. First, Duquesne's proposal would require annual reexamination of the Company's returns on capital. Second, Duquesne's proposal contemplates review of its earnings on a total company basis, including a review of its generation earnings, which will be subject to the competitive market. Third, the Company can effectively evade an over-earnings finding by using such "excess earnings" to fund marketing efforts or offer rate discounts associated with unregulated market transactions.

The OCA proposed a current valuation of stranded costs and recovery of these costs over the seven-year CTC recovery period, except the Company should not be permitted to recover a return on the unamortized balance of its owned-generation assets. With that adjustment, the OCA claimed its proposal will reduce rates to a just and reasonable level. (R.D., p. 121).

The City maintained that the Company manipulates its stranded cost claim in an attempt to thwart the goals of the Act. Rather than promoting competition and making its service area more attractive for business development, the City asserted that Duquesne's stranded cost claim virtually assures that there will not be any competition with Duquesne in the generation market place for many years to come and Duquesne's ratepayers will continue to pay some of the highest rates in the United States for at least the next eight years. The City asserted that Duquesne's proposal does not promote competition or make its service area more attractive for business development.

The City asserted that Duquesne's stranded cost valuation approach is rife with errors that seriously inflate Duquesne's claim and provide an incentive to maximize,

rather than minimize, stranded costs. The City contended that Duquesne's stranded cost calculation methodology impairs formation of a competitive market and minimizes traditional risk faced by utility investors. The City argued that Duquesne's stranded cost claim must be denied in its entirety, unless Duquesne commits to divest itself of its generating assets. The city reasoned that divestiture will not only result in an immediate transition to a competitive market, but is a more credible method of valuing assets than merely ascertaining stranded costs. The City continued that divestiture will also have the benefit of creating generation competition in Pittsburgh. The City further noted that the market is fully capable of valuing assets now as is evidenced by the numerous asset sales that have occurred and are expected in the near future. (R.D., p.123)

DII argued that the Duquesne proposals delay asset valuation past the start of the direct access phase-in must be rejected. DII reasoned that acceptance of either of the Company's delayed approaches would prevent this Commission from quantifying Duquesne's net transition and stranded costs in this proceeding, which is inconsistent with the provisions of the Act, precedent established in PECO Energy, and the public interest. DII agreed that divestiture of all of Duquesne's generating assets (as Duquesne has offered) would satisfy the need for a definitive level of stranded costs as of the beginning of the transition period. DII cautioned that many additional issues must be addressed affecting the immediate divestiture that may undercut the viability of this option.

DII proposed to establish the market value of Duquesne's generating assets based on a market price forecast and an asset value methodology of computing stranded costs. The DII methodology offered prediction of revenues that a generating unit will be able to earn in the competitive environment. DII suggested that this methodology is a reasonable compromise of the competing interests and the only method that the Act contemplates. DII noted that this Commission used a determination of stranded

generation costs based on application of a market price forecast to the asset value methodology to find the known and measurable level of PECO's total stranded generation costs in PECO Energy, Slip Op., pp. 80-91. DII averred that this precedent, as well as other portions of the Act, required a similar calculation based on an asset value methodology to establish Duquesne's stranded cost entitlement. (R.D., p.127).

HSS/ARI asserted that Duquesne has not proven, even on a preliminary basis, that it has any stranded costs. HSS/ARI criticized Duquesne's proposals extensively and asserted that Duquesne has failed to carry its evidentiary burden to support its request to accelerate amortization and depreciation. HSS/ARI noted that Duquesne derives its estimated range of claimed post-2005 remaining stranded costs by relying upon computer-generated market price projections, notwithstanding its own criticisms of such projections. (R.D., pp. 128-129). HSS/ARI noted that Duquesne admits it overstates its projected costs and that as a result, as of January 1, 2006, Duquesne may not have any stranded costs at all. As a result of its examination, HSS/ARI concluded that Duquesne failed to meet its burden of proof and should be denied any stranded cost recovery.

HSS/ARI concluded that Duquesne had substantial evidence of the market value of Duquesne's generation assets that the Company did not put in the record in this case. HSS/ARI argued that actual valuations of Duquesne's assets performed by the Company and its consultants mere months before the filing of the 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, according to HSS/ARI.

HSS/ARI concluded that 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, according to HSS/ARI.

Finally, HSS/ARI argued that Duquesne has failed to undertake actions that could have or would have mitigated any stranded costs Duquesne claims to have. (R.D., p.132). HSS/ARI contended that Duquesne's generation assets have positive market value. HSS/ARI requested that this Commission: (i) deny Duquesne's request to accelerate depreciation and amortization; (ii) deny Duquesne recovery of any amount claimed to be a stranded cost; (iii) deny Duquesne the right to charge its customers a CTC; and (iv) deny Duquesne's request to have its potential stranded costs reexamined through a final valuation conducted at some future date. (R.D., p. 133).

The IBEW did not specifically address the valuation method used by Duquesne, except to contend that it is unlawful to the extent that it gives this Commission the authority to order Duquesne to close or sell a power plant. Likewise, the IBEW did not specifically address the valuation method used by various other parties, except to note they also are unlawful to the extent they give the Commission the authority to order Duquesne to close or sell a power plant. The IBEW suggested that the lack of information concerning the proposed sale of Duquesne's power plants is striking. The IBEW challenged that neither Duquesne nor any other party attempted to evaluate the effect of plant sales or closures on Duquesne's employees. (R.D., p.134).

The PRA urged the Commission to reject any deferral of a determination of the Company's stranded costs. It found several problems with deferral from both a practical standpoint, as well as a legal one. The PRA argued that deferral of the determination of the level of stranded costs recoverable from ratepayers is contrary to the dictates of the Act. The PRA proffered that the Act requires a rapid deployment of a competitive retail generation market in Pennsylvania. The PRA suggested that an important component of the development of that market is the recovery of stranded investment by electric utilities to ensure that utilities have a fair opportunity to permit their investors to recover their investment in a Pennsylvania plant and that ratepayers have complete understanding of the cost of paying for stranded investment in their electric utility. (R.D., pp. 140-141).

In addition, the PRA claimed that Duquesne's proposal to defer calculation of a definitive stranded cost level is primarily one which shifts risk associated with stranded costs from stockholders to customers. The PRA urged that the Legislature never intended customers to face exposure to uncertainty regarding the CTC. The PRA asserted that the Legislature required the CTC to be established during the restructuring period and not at a future date. According to the PRA's argument, customers are entitled to some certainty as to the cost they will pay through the CTC in order to evaluate properly their necessity of accessing a competitive retail generation market. The PRA contended that if a Duquesne customer desires to purchase from an alternative supplier, there is no certainty as to the level of the CTC charges the customer will face in any given year. The PRA concluded that this Commission must reject Duquesne's proposal (R.D., p. 146).

The Environmentalists took no position on Duquesne's valuation proposal for stranded costs nor the positions of any other intervenor, which will entail divestiture of assets. Instead, the Environmentalists noted a higher stranded cost award means a

higher CTC in the unbundled rates. The Environmentalists suggested that, because of the rate cap, a higher CTC means a lower generation or shopping credit, which means less of the bill is subject to competition and customers will have less opportunity to obtain savings from alternate suppliers. The Environmentalists argued that this result means alternate suppliers will have a tougher time entering and staying in the market, robust competition will fail to develop, and the promise of the Act will remain unfulfilled.

These issues are important according to the Environmentalists because the absence of competition will slow down the introduction of new, clean generating options (both fossil-fueled options and renewable resource options). In addition, the Environmentalists argued that a high stranded cost recovery will indirectly subsidize existing generation, including older, inefficient polluting units. These emissions will make it more difficult to maintain air quality at levels sufficient to protect human health and property in the view of the Environmentalists. They also suggested that this result in turn may impose restrictions on economic development, constraining the citing of manufacturing operations or competitive power producers. The Environmentalists contended that treatment of stranded costs will have a very large impact on the fate of the current generation of polluting and unsafe generating plants and whether and when Pennsylvania moves to a new and healthier electric future. (R.D., p.147).

MAPSA maintained that the CTC, by its very definition, is a device that allows utilities to recover costs which are not recoverable in the ordinary competitive market. MAPSA suggested that the CTC, by its very nature of imposing above-market costs on ratepayers, is an anti-competitive device which serves to allow utilities to recover some of their prior investments which now have turned out to be "above-market." (R.D., p.149).

MAPSA further argued that the collection of utility stranded costs through the CTC can and will be used by electric utilities as a "cleverly designed" device to allow the utilities to charge under-market, and possibly even under-cost, prices for generation, and still recover the previously allowed stranded costs and profit. It is possible for a utility in the new competitive world to charge an under-market (or even under-cost) generation rate and still recover its full pre-1997 revenue requirement by using the CTC to recover the difference. All that is required to accomplish this result is to convince this Commission, in these restructuring proceedings, that the market price will be lower than it actually turns out to be. MAPSA suggested that the utilities clearly have a tremendous incentive to use the lowest possible number for "market price," where market price is used to calculate stranded costs. (R.D., p.150).

MAPSA asserted that, without competition, there are no "stranded costs" by definition, under the provisions of Section 2803 of the Act. MAPSA argued that Duquesne's proposal for calculation of stranded costs fails to meet the known and measurable standard and is based upon faulty market price assumptions. MAPSA urged the conclusion that Duquesne's proposal is seriously flawed and contrary to the statute and that it should be rejected.

Enron adopted the position of MAPSA with respect to these issues. (R.D. pp. 149-158). Further, Enron strongly endorsed Duquesne's proposal that its level of stranded costs be determined by divestiture of its generating assets and that such divestiture take place "today." Enron found Duquesne's "immediate auction" alternative consistent with the Act because it allows the market to provide evidence of the value of Duquesne's generating assets in a competitive retail marketplace. Enron's main concern, however, was that the proposal for an immediate divestiture was not superseded by other proposals that may be advanced in an extraneous proceeding involving the

APS/Duquesne merger. Enron posited that Duquesne's offer to be subjected to an immediate auction should be accepted unconditionally and that this offer should be final and not subject to any modification as a result of the merger proceeding. Enron suggested that a careful reading of the Act mandates an unconditional acceptance under the required procedures set forth in the Act,[14] which appears to require a "once and done" determination.

3. ALJ's Recommendation

The ALJ recommended that this Commission accept Duquesne's proposal to offer an immediate divestiture of its generating assets to determine the value of its stranded utility generation cost. The ALJ recommended that, within 90 days of entry of a final Order in this case, Duquesne should file with this Commission a plan of divestiture, together with a proposal for addressing its continuing obligation to serve under the rate cap. All interested parties should have an opportunity to respond to either or both proposals. The ALJ calculated that this divestiture should occur within 18 months of entry of a final Order disposing of the application in the event the proposed merger is not consummated for any reason whatsoever. Concerning the issue of an interim CTC and shopping credit to take effect January 1, 1999, the ALJ proposed that Duquesne should apply the same rates and credits approved in the pilot program for customers electing direct access during this interim period.

Finally, relating to the issue of what method to use for calculating a "permanent" CTC, using market values produced by the divestiture, the ALJ urged this Commission to direct the Company to adopt the general approach used in PECO Energy.

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[14] See, 66 Pa. C.S. §2806(f) ("The [C]ommission shall . . . issue an order accepting, modifying or rejecting [a restructuring] plan."). (Enron R.B., p. 13, fn. 32).

The ALJ would permit Duquesne to fully recover (e.g., with no "sharing" and a compensatory return on equity) its stranded costs as established by the market values produced by the auction. The ALJ would require Duquesne to submit a proposal to address its continuing obligation to serve at the same time that it files a final CTC calculation, using market values produced by the auction. (R.D., p. 160).

4. Parties' Exceptions

Duquesne excepts that a longer time frame may be necessary.

The IBEW excepts to the ALJ's recommendation that the Commission order Duquesne to sell its power plants if Duquesne does not merge with Allegheny Power. (IBEW Exc., p.2). The IBEW states that, in response to proposals made by several other parties, Duquesne has proposed to sell its power plants if the Commission permits it to do so. The IBEW notes that Duquesne made it clear, however, that selling its plants was not its preferred method of valuing its stranded costs and that it does not believe that such a sale is the best course of action. However, Duquesne has offered to "waive our right" and sell its plants if the Commission so orders. (IBEW Exc., p.2).

The IBEW suggests that the ALJ apparently accepted Duquesne's offer, without considering any of the legal or factual reasons why the Commission cannot and should not order Duquesne to sell its power plants. The IBEW contends that this Commission lacks the legal authority to order, or otherwise compel, Duquesne to sell any of its power plants. Section 2804 of the Public Utility Code, Section 2804(5), specifically prohibits the Commission from ordering a utility to sell any of its facilities, stating: "The commission may permit, but shall not require, an electric utility to divest itself of facilities or to reorganize its corporate structure."

The IBEW supports its arguments by noting that one of the fundamental principles of utility regulation in this Commonwealth is that this Commission does not sit as the "super board of directors" over a utility and neither owns nor controls a utility's property. (Northern Pennsylvania Power Co. v. Pa. PUC, 333 Pa. 265, 267-68, 5 A.2d 133, 134-35 (1939)).

The IBEW further contends that unless Duquesne makes a voluntary commitment, free of any coercion by the Commission, to sell its power plants, then the Commission cannot order or expect those plants to be sold. The IBEW points out that Duquesne's President made it clear that the Company did not make a voluntary commitment to sell its power plants. Rather, it was willing to waive its protection under the law from having the Commission order it to sell its power plants. However, the Company cannot waive the protection that the law gives to others, including the utility's employees and the communities where those plants are located. (See Section 2802(18)). The IBEW further suggests that, more importantly, the Company cannot give this Commission authority that this Commission does not have under the law.

The IBEW argues that it is not in the public interest for Duquesne to sell or close any of its power plants. Even if it were a good idea to have Duquesne sell or close its power plants and that any stranded cost proposals based on this Commission ordering the sale or closure of a power plant must be rejected. (IBEW Exc., pp. 2-7)

5. Resolution

(a) Divestiture

The record in this case includes substantially different overall approaches to determining recoverable stranded costs and significant differences in many details. The extremely varied proposals in this proceeding make it appropriate at the outset to clarify the concept of recoverable stranded costs under the Act. The definition of stranded costs in Section 2803 provides the framework that we must adopt. Even if the Commission agreed with the alternative proposals of several of the parties, many of those proposals are inconsistent wit the Act and may not be adopted.

In particular, the definition of stranded costs requires that the costs are: 1) in fact stranded, meaning not recoverable in a competitive market; 2) stranded as a result of the transition to competitive markets; 3) generation related, not transmission or distribution costs; 4) known and measurable; 5) determined over the life of the asset; 6) only a "net" amount; 7) unmitigated; and 8) determined on a net present value as of January 1, 1999.

As discussed below, we accept Duquesne's proposal to divest its generation assets as a proper method to value Duquesne's utility generation in compliance with the Act. We reject Duquesne's other approaches, both as applied to stranded utility generation and to other stranded assets, because Duquesne's proposals ignore the assumptions, definitions, and directives of the Act that stranded costs are to be determined in this proceeding at a net present value as of December 31, 1998. Section 2808(a) authorizes the collection of stranded costs through a CTC only following the

determination of just and reasonable recoverable stranded costs by the Commission pursuant to 2808(c).

We cannot accept Duquesne's basic proposal that it should continue to collect the total level of existing rates until stranded cost recovery is complete. Such a proposal would preclude the development of a competitive market or any consumer savings for many years and is not consistent with the Act. As discussed below, we do not accept Duquesne's suggestion that a determination of the value of stranded generation assets in a few years or through projections at that time will render a more accurate determination of stranded costs. Other than its immediate divestitire proposal, we cannot agree that Duquesne's proposals are preferable because they rely on actual market evidence. We are not convinced that Duquesne's proposals other than divestiture reflect all actual market evidence.

As described in the following sections of this Order, we determine the net present value of Duquesne's stranded costs, recoverable under the definition of stranded costs in the Act, as of January 1, 1999.

We agree with the ALJ that it is an economic tenet that the marketplace determines the true value of an asset. Specifically, an actual "arms length" market transaction between a willing seller and a willing buyer to determine the value of an asset is superior to the expert predictions of what the future value of that asset may be.

We find that a present divestiture of utility generation can reasonably satisfy the "known and measurable" criteria set forth in the Act. Therefore, as recommended by the ALJ, we accept the rejoinder offer of Duquesne to divest itself of generation if the proposed DQE-APS merger is not consummated. We also accept

Duquesne's proposal to offer that divestiture of its generating assets in order to determine the value of its stranded utility generation. In the event the proposed merger with APS is not consummated for any reason whatsoever, divestiture should occur, preferably within 18 months of entry of our final Order disposing of the application. As noted in Duquesne's exceptions, we recognize that a longer time frame may be necessary. A more specific time frame will be determined in the divestiture proceeding involving Duquesne.

Within 90 days of entry of this Order in this case, and in conformity with the guidelines established below, Duquesne should file a plan of divestiture of its generating assets, together with a proposal for addressing its continuing obligation to serve under the rate cap. All interested parties should have an opportunity to respond to the divestiture and/or obligation to serve proposals.

Duquesne is directed to provide the following items in its divestiture plan:

1. Company shall file the proposed plan for divestiture within 90 days.

2. The plan shall be served on all parties to this proceeding.

3. Parties shall file comments to the filed plan within 60 days.

4. Duquesne shall file a response to comments and accepted revisions within 30 days, thereafter.

5. The plan shall detail a schedule for pre-bid conferencing and the exchange of relevant information.

6. The plan shall disclose those assets and/or operational criteria of an asset essential for the continued reliability of service in the Duquesne territory.

7. The plan shall include a discussion of the treatment of shares of nuclear and fossil units for whom Duquesne is a minority owner. Specifically, the plan shall delineate Duquesne's proposed treatment of nuclear ownership shares should no bids materialize for those

shares, as well as Duquesne's ability to sell its stake in Beaver Valley 2 and Perry 1 to the other owners of those units or to swap Duquesne's stake in these units with the owners for the output of other fossil units.

8. Divestiture shall include both fossil and nuclear assets.

9. Proposals may be accepted for an individual asset or portion thereof.

10. The plan shall detail the approvals necessary for the acquisition of an individual asset or portion thereof.

11. The plan shall disclose environmental obligations of a particular asset and enforcement agreements entered into by Duquesne associated with an asset. The plan should detail the handling of current trust funds and reserves associated with environmental liabilities.

12. The plan shall describe the transmission access available to a particular asset and any general transmission agreements associated with a particular asset.

13. The plan shall include tracking and accounting for the transaction costs associated with the divestiture activities, both internal and external.

14. The plan shall describe the ratemaking accounting for use of proceeds of the plan as it relates to offsetting the generation and regulatory stranded costs and the computations of the CTC and shopping credit.

15. The plan shall include opportunity provisions for the continued sale of output to permit Duquesne to satisfy its obligation as provider of last resort.

16. The plan shall set forth transitional issues and the resolution of those issues in a manner that is fair to customers, investors, the employees of the Company, local communities, and other affected parties.

We would also note that as divestiture may not be accomplished by January 1, 1999, for the interim period the shopping credit in use shall continue to be the Pilot Customer Participation Credit ("CPC") and energy credits. Upon determination of the

value of Duquesne's utility generation assets, following implementation of the divestiture plan, a CTC shall be adopted that reconciles the actual stranded utility generation value with the interim amount collected, as described below.

With regard to the exceptions of the IBEW, we note that its reliance upon Section 2804(5) of the Public Utility Code (66 Pa. C.S. § 2804(5)) is misplaced. This section states that:

> The Commission may permit, but shall not require, an electric utility to divest itself of facilities or to reorganize its corporate structure.

It is clear that this section of the Act expressly gives us the authority to approve a divestiture of facilities or other reorganization by an EDC. In the present case, we are accepting an offer made by the Company. Moreover, we have not ordered Duquesne to sell its generating units. The IBEW's claim that we are some how sitting as a "super board of directors" over Duquesne's operations is also in error. We are accepting a proposal made by Duquesne and are in no way dictating that it divest itself of the generating units in question.

The IBEW statement that Duquesne is not voluntarily offering to sell its generating plants, but actually waiving its right to be protected from an order directing it to sell the generation facilities is not supported by the preponderance of the record which shows that the Company constructed a detailed plan and presented it of its own volition.

The IBEW claims that allowing Duquesne to sell these assets violates the rights of its employees and the communities given them in Section 2802(18) of the Act (66 Pa. C.S. § 2802(18)) is also baseless. The divestiture plan must consider environmental, employee, and community impact, as described above. IBEW and all

other parties may raise issues in response, and the approved divestiture plan will consider all issues as appropriate.

(b) Non Divestiture

In the event that Duquesne does not file a Divestiture Plan within 90 days from the date of entry of the final Order in this case, in conformity with the foregoing guidelines, the value of Duquesne's stranded utility generation shall be determined based on the record of this proceeding as described below. The first task in making such a determination is to ascertain the net book value of Duquesne's utility generation as of January 1, 1999. Second, we must ascertain the market value of those assets as of January 1, 1999. The difference between the net book value and the market value of the assets as of January 1, 1999 is the stranded utility generation amount. We note that the determination is the exact same in the event of divestiture, except that the proceeds of the sale shall be used instead of the market valuation adopted herein.

6. Summary and Conclusion

We find that only a market-based determination of stranded costs can reasonably satisfy the "known and measurable" criteria set forth in the Act. Expert predictions based upon market price projections are subject to errors of estimation and are inherently inferior to valuations based upon market data.

Therefore, as recommended by the ALJ, we accept the rejoinder offer of Duquesne to divest itself of generation if the proposed DQE-APS merger is not consummated. We also accept Duquesne's proposal to offer that divestiture of its generating assets in order to determine the value of its stranded assets. In the event the

proposed merger with APS is not consummated for any reason whatsoever, divestiture should occur, preferable within 18 months of entry of our final Order disposing of the application. As noted in Duquesne's exceptions, we recognize that a longer time frame may be necessary. A more specific time frame will be determined in the divestiture proceeding involving Duquesne.

Within 90 days of entry of final Order in this case, and in conformity with the guidelines established below, Duquesne should file a plan of divestiture of its generating assets, together with a proposal for addressing its continuing obligation to serve under the rate case. All interested parties should have an opportunity to respond to the divestiture and/or obligation to serve proposals.

B. Generation Related Stranded Costs (Recovery Pursuant to Section 2803(3))

1. Net Book Value

(a) Total Net Book Value

(i) Positions of the Parties

The Company claimed a net book value for its generating plant of $917.61 million. The Company asserted that this value is net of claims for M&S and fuel related sunk costs of $41.11 million, the present value of the lease expense for Beaver Valley 2 of $475.57 million, and deferred income taxes of $197.33 million. (R.D., p.160).

The OTS found that the total net book value of Duquesne's fossil generating plants should be reduced by $65.58 million to reflect a disallowance of the

stranded cost claim made by Duquesne with respect to Phillips Power Station (Units 1, 2, 3, and 4) and Brunot Island Power Station (Units 3 and 4). Furthermore, the OTS asserted that if a one-time administrative valuation of stranded costs is required as of January 1, 1999, then the Company's claim for $1,236.95 million in net book value should also be reduced by $41.11 million ($33.40 million nuclear and $7.70 million fossil) for the category "M & S and Fuel-Related Sunk Costs." The OTS' resulting net book value is $1,139.22 million ($764.14 million nuclear and $375.08 million fossil. (R.D., p.161).

The OCA estimated the total net book Value of the Company's owned generation assets to be $913.02 million, excluding Beaver Valley 2 lease costs and $1,274.91 including those costs (net of tax). (R.D., p.161).

DII used Duquesne's quantification of net generating plant and CWIP balance of $979.130 million at December 31, 1998. (R.D., p.162).

HSS/ARI claimed that Duquesne failed to satisfy the "known and measurable" standard imposed by the Act as a predicate to recovery of any stranded costs. HSS/ARI did not dispute Duquesne's calculation of a net book investment in generation-related assets is $1.236 billion. However, HSS/ARI did 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. (R.D., pp. 162-163).

The PRA urged adoption of the OCA's calculation of total net book value to be utilized for calculating the Company's stranded investment in owned-generating plant. (R.D., p.164).

(b) Beaver Valley 2 Lease Costs

(i) Positions of the Parties

Duquesne claimed that the present value ("PV") of its Beaver Valley Unit No. 2 lease expense is $278.24 million. The OTS, the OCA and DII all agreed that Duquesne should be permitted to recover the costs of the lease payments for Beaver Valley Unit No. 2.[15] (R.D., p.164).

The OTS included a nuclear stranded cost allowance of $287.19 million for the present value of the Beaver Valley 2 lease expense. (R.D., p. 165).

The OCA argued that the level of recovery under Section 2808(c)(3) of the Act is a discretionary determination and recovery under Section 2808(c)(1) and (c)(2) is not discretionary. Duquesne proposed to treat only $32.48 million associated with Beaver Valley 2 as an "owned-generation" asset and proposed to treat the lease payments as regulatory assets subject to recovery under Section 2808(c)(1). The OCA submitted that the entire amount of the Beaver Valley 2 lease should be classified as owned-generation and subject to Section 2808(c)(3). (R.D., pp. 165-166).

DII agreed that Duquesne should be permitted to recover the Beaver Valley 2 lease costs, but sought to ensure that the Company does not recover the costs in two portions of its stranded cost calculation. The DII maintained that its treatment of these

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[15] Duquesne entered into a sale-leaseback transaction that removed the Beaver Valley 2 asset from its books. Duquesne M.B. at 24, fn. 10; Duquesne St. 2 at 9; Duquesne St. 2-R at 57.

costs ensures no double recovery. (R.D., p.167). The PRA concurred with the approach of the OCA on this issue. (R.D., p.168).

3. Phillips and Brunot Island Costs

(a) Positions of the Parties

Duquesne claimed $65.58 million net book value[16] for Units 1, 2, 3, and 4 at Phillips Power Station and Units 3 and 4 at Brunot Island Power Station. (R.D., p.168).

The OTS opposed inclusion of the Phillips and Brunot Island cold reserved units in the Company's stranded cost claim as being contrary to the Act and stated that costs for generating plants that are not "used and useful" are not traditionally recoverable under a regulated environment. The OTS further argued that Duquesne has not met its burden of proving the costs relating to its cold reserved units that are traditionally recoverable under a regulated environment or those costs are attributable to plants no longer used and useful because of the transition to retail competition. (R.D., pp. 170-171).

The OCA noted that the Company's and the OCA's net book value differ by only $5 million. The OCA further noted that this difference reflects the OCA's adjustment with respect to treatment of Brunot Island Units 2B and 3, which are currently in cold reserve. (R.D., p.171).

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[16] The OTS noted that the $106.8 million claim for the cold reserve units mentioned in OTS' witness Mr. Metro's testimony is the $65.58 million rate base amount plus approximately $40 million in deferred taxes. OTS M.B. at 22, fn. 4; OTS Cross Exh. 3.

HSS/ARI also opposed the Company's claim relating to stranded costs for Phillips and Brunot Island. For purposes of considering Duquesne's stranded cost claim, HSS/ARI argued that 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. (R.D., p.173).

The PRA agreed with the OCA that the cost of the cold storage units of Phillips and Brunot Island should be included in the net book value. (R.D., p.175).

(b) ALJ's Recommendation

If a one-time administrative valuation of stranded costs is required as of January 1, 1999, the ALJ recommended that the Commission adopt the Company's calculation of net book value for its generation-related stranded costs, with the following adjustments. The ALJ concluded that the Commission should allow Duquesne its claim of $41.11 million ($33.40 million nuclear and $7.70 million fossil) for the category "M & S and Fuel-Related Sunk Costs," since this claim appears reasonable and no substantial reason exists to deny it. Furthermore, the ALJ recommended that the Commission should also allow the Company to include $475.57 million representing the lease expense for Beaver Valley 2. However, for the reasons the OCA advanced, the ALJ concluded that we should treat the lease payments as part of the net book value of "owned-generation" rather than as a regulatory asset subject to recovery under Section 2808(c)(1) of the Act.

Additionally, the ALJ recommended that we not include $65.58 million net book value for Units 1, 2, 3, and 4 at Phillips Power Station and Units 3 and 4 at Brunot Island Power Station. (R.D. pp. 175-176).

(c) Parties' Exceptions

HSS/ARI excepts to the ALJ's Recommended Decision by asserting that the ALJ erred in his recommendation that Duquesne be permitted to include in net book value, for purposes of calculating stranded costs, expenditures that Duquesne has not shown to be just and reasonable. HSS/ARI further contends that the ALJ erred by failing to order an immediate rate reduction to reflect a disallowance of such expenditures.

HSS/ARI also excepts to the ALJ's conclusion that HSS/ARI failed to introduce a credible issue with respect to the expenditures included in Duquesne's 1996 Test Year cost of service. The ALJ concluded that HSS/ARI failed to "identify even a single expenditure as unreasonable," thus improperly shifting the burden of proof to HSS/ARI. HSS/ARI contends that the Commission has stated emphatically that "[a]n intervenor challenging a company claim supported only by the utility's bare assertion 'was under no obligation to adduce either evidence or analysis.' Accordingly, HSS/ARI argues that the ALJ misread the law with respect to the burden on HSS/ARI in challenging the Company's expenditures. (HSS/ARI Exc., p14.).

HSS/ARI further assert that the ALJ erred by including in Duquesne's net book value a portion of Duquesne's remaining net book investment in the cold-reserved Phillips and Brunot Island facilities. HSS/ARI states that in the Recommended Decision, the ALJ correctly ruled that the net book value of Units 1, 2, 3, and 4 of the Phillips Power Station and Units 3 and 4 at the Brunot Island Power Station should be disallowed. (R.D. pp. 175-76). However, the ALJ erroneously disallowed only $65.58 million associated with those plants. (HSS/ARI, Exc. p 16).

HSS/ARI and the OTS assert that it is undisputed that Duquesne's net book investment in the cold-reserved units is $106.8 million. The OTS notes that the $65.58 million disallowed by the ALJ, is net book value, net of taxes. (OTS Exc. p. 18 f. 5). Accordingly, HSS/ARI and the OTS contend that the Recommended Decision should be modified to provide for the disallowance of the full $106.8 million in Duquesne's net book investment in the cold-reserved units. (HSS/ARI Exc. p. 16, OTS Exc. p. 19).

Duquesne excepts to the ALJ's finding that the costs of the cold-reserved Brunot Island and Phillips units cannot be recovered because these costs were not stranded by the Act. Duquesne stated at page 12 of its exceptions that the notion that these cold-reserved units are not stranded by the Act, while perhaps superficially appealing, is incorrect as a matter of fact. Duquesne argues that the Company's decision to place a unit in "cold reserve" – rather than to retire it – is based on the very expectation that the unit will have value in a future year. Therefore, Duquesne asserts that the past treatment of these units supports recovery of their costs. (Duquesne Exc. p. 12).

(d) Resolution

In determining the Total Net Book Value under the merger scenario, we find that the principal starting point shall be the OCA valuation as expressed by Duquesne in Appendix B of its Reply Brief in this proceeding. A one-time administrative valuation of stranded costs is required as of January 1, 1999, and we will adopt the Company's calculation of net book value for its generation-related stranded costs, with the following adjustments. We will adopt the OCA's level of working capital of $61.53 million as this claim appears reasonable and supported by the evidence of record. We note that Duquesne identified this claim but did not include it within its claim of stranded costs. Ostensibly, Duquesne's working capital is comprised of items traditionally recoverable through base

rates. The items in this claim include fuel inventory and materials and supplies (M&S) as maintained at each plant site.

We find that it is reasonable and appropriate to allow the Company its stated claim of $475.95 million representing the lease expense for Beaver Valley 2. As the OCA explained, the sale leaseback transition of Beaver Valley 2, is a "financing vehicle" and that the facility is "owned" by Duquesne. (R.D., p. 166). Therefore, we shall treat the lease payments as "owned-generation", rather than as a regulatory asset subject to recovery under Section 2808(c)(1) of the Act.

We find that the OTS' adjustment to exclude the Company's claim of fossil plant stranded costs of $65.58 million net book value for Units 1, 2, 3, 4 at Phillips Power Station and Units 3 and 4 at Brunot Island Power Station to be reasonable and in accord with the evidence. We note that Section 2803 of the Act defines "stranded costs" as costs that are traditionally recoverable under a regulated environment. Costs for generating plants that are not "used and useful" are not traditionally recoverable under a regulated environment.

While the Act provides an exception for costs attributable to physical plants no longer used and useful because of the transition to retail competition, Duquesne acknowledges that these units were placed in cold reserve and removed from rate base more than ten years ago, when no competitive electric generation market for Duquesne's end use customers existed. (Tr. 195-196). It is evident that the Act and the transition to a competitive generation market played no role in the decision to "cold reserve" these units. Accordingly, consistent with the provisions of the Act we find that the Company's claim, for inclusion of the net book value of Phillips and Brunot Island in our stranded cost determination, is not meritorious and, therefore, it is denied.

Premised on our review of the record as developed in this proceeding, we find that it is reasonable and appropriate to allow the Company its stated claim of $475.95 million representing the lease expense for Beaver Valley 2. As the OCA explained, the sale leaseback transaction of Beaver Valley 2, is a "financing vehicle" and that the facility is "owned" by Duquesne. (R.D., p. 166). Therefore, we shall treat the lease payments as "owned-generation", rather than as a regulatory asset subject to recovery under Section 2808(c)(1) of the Act.

e. Summary

In determining the Total Net Book Value under the merger scenario, we find that the principal starting point shall be the OCA valuation as expressed by Duquesne in Appendix B of its Reply Brief in this proceeding. We shall adopt the OCA's level of working capital of $61.53 million as this claim appears reasonable and supported by record evidence.

Based on our review of the record as developed in this proceeding, we find that the OTS' adjustment to disallow Duquesne's claim of fossil plant stranded costs of $65.58 million net book value for Units 1, 2, 3, and 4 at Phillips Power Station and Units 3 and 4 at Brunot Island Power Station to be reasonable and in accord with the evidence.

We conclude that the Duquesne RFP process was seriously flawed and its use would result in an administratively determined market price that bears no relation to whether the price that consumers are likely to pay in a competitive market or the price which suppliers can be expected to provide generation.

We shall treat the lease payments as "owned generation", rather than as a regulatory asset and we find that it is reasonable and appropriate to allow Duquesne its stated claim of $475.95 million representing the lease expense of Beaver Valley 2.

2. Market Value

a. Future Market Value of Duquesne's Generation

Three witnesses in this case submitted market price and market revenue projections for Duquesne's portfolio of generation: Michael Schnitzer (Duquesne), Douglas Smith (OCA) and Randall Falkenberg (DII). In addition, Dr. Robert Weisenmiller (HSS/ARI) provided testimony on various issues affecting the market value of Duquesne's generation assets. We find the testimony of OCA witness Smith to be the most reasonable and credible for utilization in this proceeding and the testimony of HSS/ARI witness Weisenmiller most credible in criticizing the Duquesne proposals and providing other evidence of market value.

i. Duquesne's Proposal

Duquesne argues that it proposes to determine market prices for the purposes of calculating its utility generation stranded costs by using "actual market evidence" wherever possible. To do so, Duquesne presented witness Schnitzer, who divided the task into two segments. First, witness Schnitzer estimates 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, Duquesne witness Schnitzer inputs computer assumptions to derive price projections for the period 2006 until the book retirement date of each of Duquesne's generation facilities. Duquesne witness Schnitzer

based his forecast (for those years) primarily on the cost of new capacity, arguing that the cost of new capacity serves as a "cap" on market prices.

Duquesne's witness Schnitzer assumes "the technology of choice for new entrants in 2006 will be a gas-fired combined cycle unit" and develops a range of prices reflecting alternate assumptions concerning capital cost, heat rate and the capital structure and payback requirements of the project. In order to determine market prices for new gas-fired combined cycle entrants, Duquesne witness Schnitzer estimates gas prices delivered into ECAR. OCA M.B. at 30-31; Duquesne St. 3 at 26-27. Using this approach, Duquesne witness Schnitzer estimates market prices in 2006 ranging from $34/MWh to $44/MWh in 2006 dollars, and escalates these prices with an annual estimate of general inflation of 2.5%. Id. at 27. He presents his results as "a real levelized price," reflecting an 84% capacity factor, which reflects the average capacity factor of Duquesne's generation portfolio. Id. Duquesne witness Schnitzer concludes that actual prices are likely to be lower than his results indicate due to improvements in technology, customer willingness to interrupt, less costly supply options than included in his projections, and entry of excess capacity into the competitive market.

Duquesne witness Schnitzer's market prices produce a range of market values of Duquesne's generating assets from $27 million at the low end to $278 million at the high end.

ii. Duquesne's Market Prices through 2005

Duquesne's witness Schnitzer bases his market price projections for the period 1998-2005 on the results of the Duquesne RFP in June of 1997. Pursuant to the RFP, Duquesne offered to sell 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 St. 7 at 6. Duquesne sent out 300 notices to marketers around the country to solicit participation in the RFP. N.T. 156. Duquesne received five bids for the one-year sale and 11 bids on the eight-year sale. Duquesne St. 7 at 9; N.T. 823. As a result of the RFP, contracts were executed with two entities for a total sale of 50 MW for one year, and with one entity for a sale of 100 MW for the eight year period. Duquesne St. 7 at 10. 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.

Duquesne witness Schnitzer used the winning bids in the RFP as the basis for his projected market prices through 2005. He adjusted the RFP results to reflect a 1998 spot market price of 1.78¢/kwh, and assumed inflation at 2.5% annually through 2005. Duquesne Exh. MMS-4.

iii. Responses of Other Parties

OCA, DII, HSS and MAPSA extensively criticized the RFP conceptual approach and the implementation of the approach as inadequate to provide a credible market valuation for the period ending in 2005. HSS/ARI provided the most detailed criticism, although OCA, DII, and MAPSA raise several of the same concerns.

Conceptually, the parties argued that the RFP provides little, if any useful information for determining the value of Duquesne's generating assets. For example HSS/ARI argues that the Duquesne RFP reflects only a wholesale price for the incremental energy produced by an existing unit. HSS/ARI argues the RFP at best measures only the incremental generating costs of incremental output from existing generation that has already

been committed. 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. HSS/ARI cites Duquesne's testimony that its "to go" or "going forward" costs for its generating units are between $23.3/MWh and $35.9/MWh on a five-year levelized basis. HSS/ARI M.B. at 32; HSS/ARI Exh. RBW-12.

HSS/ARI argues that in a competitive market, a firm only will commit to sales at prices at least covering its "to go" costs, and that most firms typically would not sell unlimited quantities for $18/MWh, as suggested by the results of the RFP, because it will cost them significantly more to produce such power on a "going forward" basis. Rather, plants with higher operating costs will not operate. As supply decreases, the market price will increase to higher levels sufficient to attract expanded operation of existing units or new capacity. Id. at 29.

HSS/ARI argues that the prices resulting from the RFP for 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 St. 1 at 27. HSS/ARI argues that the proposition that a solicitation for 50 MWs of electricity (or even 500 MWs) is a meaningful surrogate for all the power needs of Duquesne, let alone the Western Pennsylvania region, is not reasonable.

HSS/ARI concludes that the RFP concept suffers fatal design flaws that disqualify its use to establish the market price of energy through 2005.

Besides conceptual flaws, several parties criticize the specific requirements of the RFP process imposed by Duquesne. HSS/ARI and City assert that Duquesne's RFP has

such restrictive rules that it must have been intended to provide the result Duquesne wanted: a low estimate of the market value of electricity that would serve to maximize Duquesne's stranded cost claim. They argue that the terms and conditions of the RFP reduced the number of potential buyers and reduced the price bid by the limited number of bidders that actually participated in the process.

First, the RFP did not contain any flexibility to accommodate differing power purchaser's needs with respect to the length of the purchase terms. HSS/ARI Exh. RBW-14. The universe of potential bidders was reduced to those needing power for exactly one year or eight years, with no flexibility in bidding. For example, the bid process could not accommodate 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. HSS/ARI M.B. at 33.

Second, the RFP explicitly excluded any firm transmission rights or any ancillary services. HSS/ARI argues that the RFP prices reflect solely the value of Duquesne's firm power at the generating station, and that power with transmission services and ancillary services available is inherently more valuable to a larger number of potential bidders, since the transmission and ancillary services are necessary to use the purchased power. Thus, the net effect of this limitation was to reduce the amount bid for the electricity. HSS/ARI M.B. at 34-35.

Third, the RFP included a "take-or-pay" provision requiring payment of 75% of the winning bid price, regardless of how much power could be delivered to its market. HSS/ARI Exh. RBW-14 at 7-8. 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 St. 1 at 36. HSS/ARI argues that the combination of the "take-or-pay" provision with the failure to assure firm transmission rights increases the real price of power to the bidder, therefore lowering the bid and limiting the number of potential bidders.

In addition, HSS/ARI identifies several actions by Duquesne related to the bids themselves. HSS/ARI suggested that Duquesne was not interested in maximizing the number of bidders or obtaining the highest bids. For instance, HSS/ARI points out that Duquesne rejected a facsimile, even though it was hand-delivered to Duquesne on a timely basis, because the RFP rules prohibited the submission of bids by facsimile. HSS/ARI 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.

HSS/ARI assert that the minimum number of bids alone should have suggested to Duquesne witness Schnitzer that there were factors at play that disqualified the RFP results from being a meaningful measure of market value. HSS/ARI M.B. at 30. For the foregoing reasons, HSS/ARI contend that the projections based upon the results of the RFP cannot provide a reasonable measure of future retail market values. HSS/ARI M.B. at 30-31.

iv. Resolution

We conclude that HSS/ARI in particular, as well as OCA, DII and MAPSA, substantially discredit the usefulness of the RFP results for establishing a market price of energy through 2005. We find that the RFP is conceptually flawed and was not implemented in a manner permitting it to provide an evidentiary basis for the valuation of

Duquesne generation assets. In particular, we reject the Duquesne RFP as a basis for projecting market prices for the following reasons:

- it reflects the incremental energy price, not the total cost for energy and capacity;

- it does not reflect any ancillary services, line losses, start-up costs, variable O&M costs, or "to go" costs such as fixed O&M costs, capital additions, or fixed fuel costs;

- it reflects the price only within the Duquesne control area, not a market clearing price that will exist in the region;

- it denied prospective bidders any assurance that they would be able to purchase firm transmission rights on Duquesne's system or from Duquesne's system to their loads;

- it required a proposed contract with a take-or pay provision at a high capacity factor, imposing a higher delivered cost in the absence of firm transmission rights.

- it was only for a one-time sale of a small amount of power that does not reflect a regional market price for competitive power;

- it proposed required terms that were not negotiable as would be the case in a competitive market; and

- Duquesne rejected a timely, hand-delivered facsimile bid at a higher price than the winning bid because the rules prohibited facsimiles.

We conclude that the Duquesne RFP process was seriously flawed and its use would result in an administratively determined market price that bears no relation to either the price that consumers are likely to pay in a competitive market or the price at which suppliers can be expected to provide generation.

b. Duquesne's Post-2005 Market Prices

Duquesne witness Schnitzer used a computer-based projection to determine the market prices and market revenues that determine the value of Duquesne's generation assets considering the period that begins in 2005 through the end of their useful lives. OCA witness Smith and DII witness used a similar method to determine the market prices and market revenues for the entire period beginning in 1999, although their modelling was substantially different.

Duquesne witness Schnitzer's projection for the post-2005 period is primarily based on the assumption that new capacity will be needed, that natural-gas fired combined cycle (cc) units will be constructed to meet the additional capacity requirements, and that the cost of such new capacity will set the ceiling on the market price of electricity. Thus, Duquesne witness Schnitzer's projections concerning the capital and operating costs of the combined cycle units, including the price of natural gas, are central to his forecast. The following discussion focuses on these key issues that strongly support our conclusion that Duquesne witness Schnitzer's forecast for the post-2005 period is not credible.

DII argues that Duquesne witness Schnitzer does not address a number of relevant factors that must be considered in a market price forecast, including the following: The relevant market for the forecast, an accurate assessment of fuel prices, consideration of information about the regional fleet of generation resources, such as generator capacities, heat rates, availability statistics, and maintenance requirements, customer demands (average energy and usage patterns), sufficient future capacity additions, and a realistic assessment of the cost and efficiency of new capacity. DII finds Duquesne's analysis simply lacks the level of detail necessary for it to provide an adequate basis for the Commission determination of Duquesne's stranded utility generation.

c. Price of capacity

Duquesne witness Schnitzer assumes capital costs for CC units in 2005 from a low of $395/kW to a high of $500/kW. In 1996 dollars, Duquesne witness Schnitzer's capital cost estimates would be $316/kW and $400/kW. N.T. 438-439. Duquesne witness Schnitzer indicated that he based his high and low capital cost estimates upon his review of industry data, including "a review of Gas Turbine World . . . indicates that . . . installed costs are now quoted as low as $318 to $380 per kW." Duquesne St. 3R at 22. The Gas Turbine World edition that Duquesne witness Schnitzer refers to was for 1997. N.T. 440.

DII and HSS/ARI assert that Duquesne capital cost assumptions are unreasonably low, thereby understating the market price of power. New units must sell electricity at prices sufficient to recover their average variable cost, which includes a contribution to the fixed cost associated with operating the unit. DII St. 2 at 16. DII assumes a capital cost of new combined cycle capacity of $595/kW and, $300/kW for an oil-fired combustion turbine. Id. at 25. These figures are consistent with assumptions used by other utilities in restructuring proceedings.

HSS/ARI presented evidence asserting that Duquesne witness Schnitzer's capital cost assumptions for the capital costs of combustion turbines are understated. HSS/ARI presented the 1996 edition of Gas Turbine World indicating prices for 28 units ranging in price from a high of $1200/kW to a low of $403/kW. HSS/ARI indicated that many of the less expensive units have prices per kW that range from $500/kW to $800/kW, substantially higher than Duquesne witness Schnitzer's high case estimate of only $400/kW. Id.

In rebuttal, Duquesne witness Schnitzer indicated that his estimates were based on 1997 Gas Turbine World data, and not 1996 data, and that prices dropped significantly from 1996 to 1997. Duquesne St. 3R at 22; N.T. 440. HSS/ARI responded that the 1997 report provides prices for 28 units excluding the smallest units, with prices ranging from a high of $1000/kW to a low of $612/kW in 1997 dollars, compared to Duquesne witness Schnitzer's high case assumption of $410/kW. Only 11 of the 28 units list prices lower than Duquesne witness Schnitzer's high case estimate of $410/kW, and only one unit has a price lower than his low case estimate of $324/kW. In general, the 11 units with prices lower than Duquesne witness 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 Duquesne witness Schnitzer, the lowest cost per kW unit listed in the report, the only one that has a lower price per kW than Duquesne witness Schnitzer's low case estimate, is the state of the art design. N.T. 440-441. Its net plant output is rated at 757.5 MW. HSS/ARI M.B. at 39-40.

Thus, HSS/ARI argues that Duquesne witness Schnitzer's capital cost high case estimate requires an assumption of one particular unit and the exclusion from consideration of the 45 other units listed in the report, regardless of the plant output needed to serve incremental load at any given time. HSS/ARI argues that Duquesne witness Schnitzer's low case estimate requires the assumption that only a state of the art unit with capacity of approximately 760 MW and an absolute cost of $240 million will serve the market and the exclusion from consideration of the 55 other units listed in the report, regardless of the plant output needed to serve incremental load at any given time. HSS/ARI asserts that such assumptions are not reasonable because many factors affect the selection of

a particular unit for installation, requiring a market projection that reflects a variety of requirements.

Duquesne witness Schnitzer testifies that his cost estimates are "installed costs" that include items such as "interconnection with the electric grid, an initial stocking of spares and materials and supplies and a fuel supply interconnection . . . (and) a cost of land." N.T. 431-433. As HSS/ARI notes, however: The 1997 Gas Turbine World report states:

> 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.[17] 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 M.B. at 41; HSS/ARI Cross Exh. 10 at 22 .

As a consequence, HSS/ARI concludes that Duquesne witness Schnitzer's presents an unreasonably low capital cost assumption that is the major input driving his post-2005 price projections, precluding its usefulness in this proceeding.

[17] Schnitzer was not familiar with the term "soft costs." N.T. 431.

i. Inflation Assumptions

Duquesne witness Schnitzer's forecast assumes a future annual inflation rate of 2.5% until 2026, the end of the analysis period.

HSS/ARI argues that an a assumption of 2.5% annual inflation through the end of the useful lives of Duquesne's generation units is unreasonably low. All of the cost components of a new generation facility are exposed to the effects of inflation. 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. Thus, HSS/ARI argues that Duquesne witness Schnitzer's assumption of an unrealistically low 2.5% inflation rate depresses market-clearing price projections, in turn inflating stranded costs.. HSS/ARI M.B. at 45-46.

HSS witness Weisenmiller independently reviewed the U.S. Department of Commerce's inflation data . He compares Duquesne's 2.5% inflation assumption to the gross domestic product price deflator ("GDPPD") and concludes that the average GDPPD has been 4.64% per year over the last 25 years and 4.2% over the last 50 years. Those historical measures of inflation exceed Duquesne's projection by more than 60%. HSS/ARI Exh. RBW-53. Moreover, Dr. Weisenmiller finds that during the last 50 years, the GDPPD never has increased on average at a rate of 2.5% or less annually for a 25-year period. Id. at 130-131. Dr. Weisenmiller also finds that outbreaks of significant inflation occur periodically.

ii. Gas Price Forecasts

Since Duquesne witness Schnitzer assumes the technology of choice in 2006 will be natural gas-fired combined cycle units, his forecast of natural gas prices is a critical factor in his post-2005 price projections of electricity. Duquesne witness Schnitzer's forecasts a basically flat nominal price ranging from $2.20 to $2.60 per MMBtu.

HSS/ARI criticizes the forecast as unreasonably low, without any substantial supporting evidence, and that it produces an unreasonably low forecast of electric prices, resulting in a higher stranded cost determination. Since the Duquesne gas price forecast is stated in nominal terms, it implies that the real price of gas, after accounting for inflation, is projected to decrease in each year at approximately the rate of inflation through 2026. HSS/ARI St. 1 at 126

HSS/ARI asserts that there are two primary flaws in Duquesne witness Schnitzer's analysis that discredit his forecast of natural gas prices. First, Duquesne witness Schnitzer assumes a wellhead gas price forecast that is low by comparison to other existing forecasts. Second, Duquesne witness Schnitzer uses a gas transportation rate that is unrealistically low. HSS/ARI M.B. at 42; HSS/ARI St. 1 at 125.

For the price of the gas itself, Duquesne witness Schnitzer bases his forecast on "quotes for forward prices through 2005 for gas delivered to Henry Hub in Louisiana." Duquesne St. 3, at 26. HSS/ARI Exhibit RBW-49 and HSS/ARI Cross-Examination Exhibit 5 identify the "quotes" as a letter from an over-the-counter securities brokerage firm concerning futures prices at Henry Hub.

HSS/ARI argues that Duquesne witness Schnitzer uses underlying source "data" for his price forecast that is remarkably shallow. HSS/ARI M.B. at 42-43. HSS/ARI witness Weisenmiller presented data from his review of publicly available natural gas wellhead forecasts released by EIA, WEFA, DRI and GRI. HSS/ARI Exh. 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% per year. HSS/ARI St. 1 at 126. 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% per year. HSS/ARI St. 1 at 128. Thus, HSS/ARI concludes that Duquesne witness Schnitzer's natural gas forecast not only is unreasonably low vis-a-vis the forecasts of industry forecasting experts, it is even far below Duquesne's own forecast officially on file with the Commission. HSS/ARI M.B. at 43.

To determine a transportation rate to get natural gas to delivery points in ECAR, Duquesne witness Schnitzer relies upon a handwritten note he received from Columbia Energy Services, an affiliate of Columbia Gas Transmission. N.T. 457-458. Based upon the handwritten document, Duquesne witness Schnitzer assumes a 24¢ transportation rate to transport natural gas from Henry Hub to the market area. N.T. 457. That differential is set forth in Duquesne Exhibit MMS-3. HSS/ARI M.B. at 43-44.

HSS/ARI presented evidence that Duquesne witness Schnitzer's transportation rate does not capture a reasonable price for the transportation of natural gas. First, the document on its face notes that CNG, another interstate pipeline that supplies transportation to the Duquesne market, "trades .06-.09 higher than Columbia Transmission. HSS/ARI Cross Exh. 7. Further, although Duquesne's witness Schnitzer believes the handwritten note he relies upon is intended to account for transportation from the Gulf Coast to ECAR, he could not confirm that quoted rate includes use of all pipelines necessary to reach Duquesne, did not review the actual tariffed rates of Columbia, and did

not consider the transportation rates of other pipelines serving the region. N.T. 462-464; HSS/ARI Cross Exh. 8.

HSS/ARI witness Weisenmiller examined historical differentials between wellhead and Midwest citygate prices to compare those data to Duquesne witness Schnitzer's transportation charge estimate of 24¢/MMBtu. He finds those differentials average in the $0.50 to $1.00/MMBtu range, or 2.5 to five times Duquesne witness Schnitzer's assumed transportation rate. HSS/ARI M.B. at 45; HSS/ARI St. 1 at 128.

iii. Resolution

The Commission accepts much of the HSS/ARI criticism of Duquesne witness Schnitzer's analysis and concludes that his testimony does not provide a credible, substantiated foundation for Duquesne's request for recovery of its stranded utility generation. We find that the evidence presented concerning the capital costs for new combined cycle units, inflation and gas prices do not reflect a reasonable review of available evidence and are not reasonable once available market evidence is considered. We find that witness Schnitzer did not conduct an adequate review of readily available market data, adopted assumptions that are inconsistent with available evidence, and produced a recommendation that is not credible, reasonable, nor substantiated by the record in this case.

d. OCA's Market Valuation of Duquesne's Generation

(i) OCA Witness Smith's Market Valuation

The OCA's witness D. Smith indicates that while Duquesne witness Schnitzer's analysis focused on the cost of entry of a new combined cycle plant as the upper bound of a range of market value, OCA witness D. Smith presents a dispatch simulation model of the APS/DLC system as a single market area using the ENPRO dispatch simulation model to estimate market revenues in each hour. OCA St. 2 at 5. OCA characterizes ENPRO as a detailed, chronological model used by utilities and others for a range of operational and planning analysis, that is well suited for the purpose of estimating market prices based on the dispatch of marginal units for a large electric system. OCA notes that the Commission specifically approved the ENPRO model as quite suitable to the task of estimating generating market revenues in PECO Energy. OCA M.B. at 31-32.

The OCA's witness D. Smith indicates that he modeled the APS/DLC region as the relevant market, while incorporating trading with other markets through the use of import proxies that reflect existing transmission limitations in the region. DII witness Falkenberg also concluded that it was preferable to model the existing region rather than make assumptions that are unsupportable at this time concerning what the relevant future regional market will be. DII witness Falkenberg concluded that using a larger region as the market would have no discernible impact on the results of the market valuation analysis.

The OCA's witness D. Smith represents the energy market in terms of bids for delivered energy from each generating unit, with each bidder assumed to bid a price sufficient to recover its average variable cost based on the unit's historical as-operated heat

rate. He testified that actual market prices can turn out to be higher because upward pressure may be exerted on prices in the Northeast and Mid-Atlantic due to an earlier need for capacity in the PJM market and retirements and unavailability in the NEPOOL market area. Id. at 14. Upward pressure resulting from the retirement of units for economic reasons may also drive prices higher than assumed by Mr. Smith, who did not test the economic viability of ECAR generating units; he conservatively assumes existing units will continue to operate. OCA M.B. at 33-34.

The OCA's witness D. Smith used the DRI fuel forecasts adopted by the Commission in PECO Energy. OCA characterized the DRI forecast as an independent, nationally respected forecast. It's accuracy and objectivity is such that PECO Energy used the DRI fuel price forecast in formulating its market valuation.

The OCA's witness D. Smith assumes that newly constructed combustion turbine units will be used for peaking duty and that combined cycle units will be used for baseload/intermediate duty. Id. He assumes all-in capital costs of $560/kW in 1997 dollars for combined cycle units and $296/kW in 1997 dollars for combustion turbines. His assumptions are based on his review of industry data and estimates provided by other Pennsylvania utilities. OCA witness Smith indicated that several factors could raise future generation costs above his projections:

- Greater interest costs during construction;
- Increase in CC/CT equipment costs from current market conditions, which represent a historical low point;
- Greater land costs;
- 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;

- Selective catalytic reduction ("SCR") equipment for control of NOx emissions on CC units. The turnkey equipment costs underlying his 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. His 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.

The OCA's witness D. Smith's analysis assumes all generators selling into the spot market at any given time will receive the same price for their output and price will reflect the highest bid accepted by the system operator, and bidders will bid hourly output based only on its variable cost. Thus, generating units with high variable costs that run infrequently will receive little or no contribution toward their fixed costs in most hours. However, such units will need to recover such costs and the market will provide mechanisms to enable the recovery of such costs.

The OCA's witness D. Smith identifies four ways in which the market will compensate for these costs: (i) bids above variable costs; (ii) interruptible demand payments; (iii) bilateral transactions; and (iv) ancillary service revenues. OCA M.B. at 33; OCA St. 2 at 12-13. OCA witness Smith expects that a combination of these mechanisms will yield market prices sufficient to support the level of system reliability that customers desire, or that is established through minimum capacity requirements. Thus, OCA witness Smith concludes that "generation market prices will most likely exceed the variable cost of

the highest-cost generating unit(s) in the market during some fraction of the year, resulting in what he terms "reliability-related" revenues. OCA witness Smith assumes in his analysis that, in the long run, such revenues are capped at the estimated cost of peaking capacity, i.e. "the real, levelized cost of a newly constructed combustion turbine." He further assumes these revenues will be concentrated in "only the highest-demand hours, so that all generating units will receive the same reliability-related revenues on a per-kW basis" and that sufficient generating capacity will be constructed to maintain an 8% reserve margin of installed capacity above the annual peak demand. OCA M.B. at 33; OCA St. 2 at 13.

(ii) Postitions of the Parties

Duquesne witness Karl criticizes some of the assumptions OCA witness Smith uses in his analysis. First, Mr. Karl criticizes Mr. Smith's use of an 8% capacity reserve margin, suggesting that Mr. Smith inappropriately uses this value as an administratively determined capacity requirement for ECAR. Duquesne St. 9R at 2. However, OCA explains that witness Smith's analysis is not based on the assumption of an administratively determined capacity requirement. OCA witness Smith assumes that customers will seek a level of system reliability comparable to historical minimum targets, which require approximately an 8% regional installed capacity reserve margin. OCA St. 2S at 2-3. The OCA submits it is reasonable to use this approach in the context of forecasting generation market prices. OCA M.B. at 36

Duquesne witness Karl also criticizes OCA witness Smith's assumption that annual peak demands and energy requirements in the APS/DLC area will increase as projected for ECAR in the 1996 NERC Electricity Supply and Demand Database. Based on this database, OCA witness Smith develops an hourly load shape based on an average of the 1995 and 1996 actual hourly shapes. OCA St. 2S at 4. Duquesne witness Karl contends

that the development of a combined load shape requires an assessment of the individual customer classes for APS and Duquesne. Duquesne St. 9R at 7. OCA witness Smith explains this is not the case for the base year, which simply represent the sum of the hourly loads of the two systems. OCA St. 2S at 4. He indicates that installed loads and usage patterns are relatively stable, making the historical curve the best basis from which to forecast. Id. In addition, OCA witness Smith explains that short term trends in load shape will have a limited impact on market prices and that other factors, such as the overall magnitude of demand growth, fossil fuel prices and the cost of new market entry are substantially more important. Id. In the long term, it is reasonable to expect that changes in the system load shape will be partially or entirely offset by changes in the generation mix, with the amounts and type of new market entrants developed to "fit" the actual load shape and market price signals. OCA M.B. at 37.

(iii) Resolution

The Commission finds the testimony of the OCA's witness D. Smith to be objective, thorough, well supported in the record of the case and credible. We conclude that his testimony provides the best evidence in the record of this case for a determination of the market value of Duquesne's utility generation and adopt the testimony of OCA witness Smith as the basis for our determination of Duquesne's recoverable stranded utility generation. The OCA's witness Smith's evaluation will not be used to determine Duquesne's stranded utility generation in the event of divestiture, as previously discussed.

Besides being the most credible and least criticized of any of the other market valuation witnesses, we note that it produces a reasonable result that is within the range of market values produced by the other credible evidence in the record of this case. We find that witness Smith's model fairly represents several key matters necessary for a reasonable

determination of market value, such as fuel prices, imports and exports, and heat rates. In addition, we find that OCA witness Smith's market prices are sufficient to support the construction of new generation capacity. The Act requires the Commission to ensure that reliability is maintained during the transition and upon the establishment of a competitive generation market.

e. Other Evidence of Market Value

In its proposal, Duquesne indicated that it was preferable to use actual evidence of market value wherever possible instead of analytic projections. HHS witness Weisenmiller presented several examples of actual market valuation as well as other Duquesne projections of market value.

(i) Ft. Martin Sale

First, in 1996, Duquesne sold its 276 MW share of Ft. Martin to a subsidiary of APS for $169 million, a price that is four and a half times the $37 million net book value of Duquesne's share of the plant. Duquesne St. 1 at 26; Duquesne St. 2 at 10-11. Duquesne's President and CEO acknowledges that the sale established the fair market value of the plant at the time of the sale. N.T. 71:15-20. OCA and HSS in particular argue this sale is the single most useful market evidence to establish the current valuation of Duquesne's utility generation, and it suggests that real market prices will capture much plant value in excess of book value.

(ii) Other Duquesne Studies

In addition, a 1995 Duquesne study concluded that sale of the Cheswick and Elrama units would yield purchase premiums above book value of between $160 million and $460 million. (HSS/ARI M.B., p. 5) The $160 million premium is based on the base case of existing operation of the plants. If power sales were increased, the purchase premium would rise to $335 million and to $460 million if sales increased and O&M costs were reduced by one-third. The same study concluded that Duquesne could capture a purchase premium of $733 million above net book value upon sale of all of its generating assets.

(iii) Metzler & Associates Study

Duquesne contracted with Metzler & Associates ("Metzler") to perform an asset valuation for Duquesne using three assumptions concerning the price of power. An assumption of $18-20/MWh was the "worst case" considered, a "most likely case" of $27/MWh was considered and a "best case" scenario of $35/MWh was considered. Exh. RBW-5 at 2. Using those assumptions, Metzler projected market values as high as $225 million for the Cheswick unit and $150 million for Elrama. Exh. RBW-6 (study dated July 15, 1996).

In an update of the initial study, Metzler increased its market value projections to $264 million for Cheswick (compared to net book value of $120 million); $224 million for Elrama (net book value $100 million); $112 million for Brunot Island (net book value $26 million); and $140 million for Phillips (net book value $78 million). Exh. RBW-7 at 3; Duquesne Statement 2, Exh. DJC-3 at 32-38 and Exh. MKO-1C at 1

(iv) CS First Boston Study

In addition to the Metzler study, Duquesne received a study of the value of Duquesne's generating assets from the investment banking firm CS First Boston in late November 1996. Duquesne later hired CS First Boston as its advisor in connection with its proposed merger with APS. Exh. RBW-10; N.T. 275. CS First Boston advised Duquesne that it could sell five of its generation plants with a total net book value of $450 million for between $827 million and $1.184 billion. Such sales would produce a premium above book value ranging from $377 to $734 million. Exh. RBW-10; HSS/ARI St. 1 at 21, Table III-1; HSS/ARI M.B. at 54. The assumed power price in the CS First Boston study is 2.6¢/kwh or $26/MWh. Exh. RBW-10.

(v) Other Market Transactions

HSS witness Weisenmiller presented other actual market evidence suggesting that some of Duquesne's generation assets could be sold at substantial premiums above book value. New England Electric System ("NEES") recently sold to U.S. Generating Company generation facilities with a book value of $1.1 billion for $1.59 billion, approximately $500 million or 40% above net book value. HSS/ARI St. 1 at 146. 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 St. 1S at 7. PG&E's sale was consummated at approximately 32% above net book value, and SoCal Edison's facilities sold at 2.65 times net book value.

(vi) Resolution

The record includes substantial evidence of actual market transactions, including an asset sale by Duquesne, that suggest market values higher than those produced by the OCA's witness Smith. We find that these transactions provide a useful parameter permitting us to conclude that the adoption of the OCA's valuation in this proceeding is exceedingly moderate. Acceptance of these studies supports the finding that Duquesne's divestiture proposal is in the public interest. We do not, however, find that the actual market transaction evidence provides an adequate basis for adopting a valuation of all of Duquesne's utility generation based on the actual sales of other units, because individual transactions are based on many specific considerations that may not be applicable to other transactions.

In addition, we conclude that the CS/First Boston and Metzler studies performed by Duquesne, for purposes other than this proceeding, provide the Commission with substantial evidence corroborating OCA witness Smith's projections of both electric prices and asset market values as exceedingly moderate. As HSS/ARI noted, if market price embedded in the CS First Boston price projection is used, Duquesne's generation assets would have a positive market value in 1998 of $481 million. Exh. RBW-57.

f. Summary of Market Valuation

We have reviewed the record concerning this issue in extraordinary detail in order to determine the most credible and reasonable market valuation of Duquesne's utility generation assets supported by the evidence in this proceeding. Our conclusion requires the exercise of judgment based on the evidentiary record. The Duquesne proposal is not credible nor reasonable. Moreover, rather than using actual market evidence wherever possible, as Duquesne claims, we conclude that it completely ignores and is contradicted by the actual market evidence that does exist. Although there is no single proposal that we find completely convincing on every component of its analysis, we adopt the testimony of the OCA's witness Smith as the most reasonable determination of future market value in the record of this proceeding. We conclude that Duquesne's utility generation has a market value of $110.95 million as of December 31, 1998 reflecting the results of the OCA's witness Smith's analysis, but not considering other considerations discussed elsewhere in this Order.

3. Proposed Adjustments to Market Value

(a) Life Extension

(i) Position of the Parties

Duquesne noted that the OCA made projections assuming that Duquesne's coal plants are "life extended" an additional 15 years. Using this adjustment, Duquesne asserts that the OCA's witness L. Smith created nearly $200 million in additional market value. Duquesne states that the OCA's projection is not based on a life extension study of Duquesne's units. Rather, it is based on studies by other utilities (PECO Energy and

APS) in other cases involving the plants of those other utilities. Therefore, Duquesne objects that these estimates cannot possibly support a "known and measurable" calculation for its units. Duquesne also cited this Commission's determination in PECO Energy (as to fossil decommissioning), to argue that such a forecast of "[p]rospective...expenses [and revenues]...without a specific plan to [life extend] a particular plant at a particular time and in particular manner" cannot satisfy the known and measurable standard. (R.D., p. 274).

The OCA noted that the Company calculated market revenues realized over the book lives of its generating units. As the OCA notes, for the Company's major coal-fired generating plants, this assumes a "useful life of approximately 40 years." (R.D., p. 274). In part, stated the OCA, this is because Duquesne believes that addressing life extension at this time would be premature. Duquesne would reserve judgment on this issue until its proposed "final valuation" in the year 2003. For this reason, the OCA argued that Duquesne was unable to provide any studies regarding life extending its generating units, but has indicated that such a study would be prepared and made available for the year 2003 valuation.

The OCA maintained that while the Company's failure to perform life extension studies is "understandable if the purpose is merely one of reporting an integrated resource plan," the Company's position is not reasonable in the context of a stranded cost study intended to provide the basis for competitive transition charges. The OCA contended that, even were the Commission to accept Duquesne's final valuation approach, life extension benefits must be considered at this time because Duquesne's stranded cost analysis is intended as a "test" of Duquesne's seven-year rate cap plan. Ignoring the likelihood of life extension means that this test is biased and distorted. The OCA stated these life extensions were incorporated in the OCA analysis in PECO, which

was adopted by the Commission. (R.D., pp. 275-276). In the PECO case, the OCA explains, PECO Energy projected, and the Commission adopted, life extensions for three coal plants. It was the study in that case which formed the basis for the OCA's $172.72 million unit life extension adjustment here. Because the Company failed to provide any substantive response to OCA's position on this issue on the record of this proceeding, OCA submitted that its economic life extension of units adjustment should be adopted. (R.D., p. 277).

Based on the foregoing, the OCA submitted that its adjustment to reflect economic life extension of units in the amount of $170.72 million is appropriate and should be adopted. In conclusion, the OCA noted that the Company has not performed such an analysis, even though it would have been appropriate to do one for purposes of determining stranded costs. Consequently, the OCA performed its own analysis using reasonable assumptions such as the escalation of market prices. (R.D., p. 277). The Company did not present specific rebuttal to the OCA's testimony with respect to life extension. The City agreed with the OCA on this issue. (R.D., p. 278).

HSS/ARI argued that one factor which caused Duquesne to overstate its stranded cost exposure was that the Company 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. Thus, argued HSS/ARI, sales of electricity from competitive plants (i.e., capable of producing electricity at below market clearing prices) can offset sales from noncompetitive plants (those capable of producing electricity only at above market clearing prices). Accordingly, the longer competitive plants operate, the greater the offset against stranded costs. Notwithstanding that fact, however, 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. Because, states HSS/ARI, many plants continue to operate after the date of full recovery of depreciation, 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.

HSS/ARI additionally point out that 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. As a result, argued HSS/ARI, plants, both competitive and non-competitive, could be operated at lower operating costs such that noncompetitive plants may, in fact, become competitive and competitive plants would become more competitive, i.e., more effective at offsetting stranded costs. Nonetheless, HSS/ARI, criticizes Duquesne's stranded cost claim as it fails to take into account such offsets.

HSS/ARI suggested that the proper indication of whether a power plant should be retired should be based on the unit's going forward costs. 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 the foregoing analysis, HSS/ARI argued that 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.

The PRA explained that extension of the operating lives of generating plants beyond their "book or financial life" is common in the electric industry. The fact that Duquesne has failed to consider this factor in its stranded investment analysis is not a basis for rejecting the validity of life extension assumptions argued PRA. The Act requires that the Commission consider all possible mitigation strategies in determining stranded investment. Consequently, states the PRA, life extensions of existing plants is a form of mitigation of the level of stranded investment. Even under the Duquesne scenario of "testing," at some time in the year 2005, a review of the possibility of extending the lives of generating plants would be required. (R.D., p. 280).

The PRA urged this Commission to adopt, as a reasonable estimate of the cost of extending the life of a coal plant that was provided by the OCA. The PRA asserted that the OCA analysis revealed that all generating units analyzed can be economically life extended at $200/kW capital costs although effective for only two units at $300/kW. Thus, according to the PRA position, the range of NPV of life extension is $200 to $171 million as of January 1, 1999. (R.D., p. 28). The OCA conservatively selected the $171 million amount. And, states the PRA, this position should be adopted by the Commission. (Id.).

(ii) ALJ's Recommendation

The presiding ALJ noted that Duquesne calculated market revenues realized over the book lives of its generating plants. Therefore, he observed that it is unreasonable to assume the physical life of a stranded asset equates exactly with its book life. Thus, some "life extension" must be attributed to that asset. (R.D., p. 281). Further, ALJ Corbett disagreed with Duquesne that addressing this issue in this proceeding is premature and should be reserved until its proposed "final valuation" in Section 2003. He

concluded that the issue of mitigation of stranded costs must be addressed now, unless there is a divestiture of generating assets as discussed. Sections 2804(4)(v) & 2808(c)(4).

Since the OCA provided the only credible evidence on this subject in this proceeding, the ALJ recommend that we adopt the OCA's adjustment of $170.72 million to reflect an appropriate economic life extension for these assets.

(iii) Parties' Exceptions

Duquesne excepted to the ALJ's acceptance of the OCA's life extension projections. Duquesne submits that the ALJ was wrong to conclude that the "physical life" of a generating asset cannot "equate exactly with its book life." It states that the "book life" of an asset is the best estimate of its projected physical life. These book lives are developed using detailed engineering and economic analysis for the purpose of establishing appropriate depreciation schedules, states Duquesne. Duquesne observes that the OCA did not undertake any study of the cost required to life-extend Duquesne's units. Rather, Duquesne repeats its criticism that the OCA used studies by other utilities which studies, it argues, cannot possibly provide a "known and measurable" calculation for Duquesne. (Duquesne Exc., p.15).

Duquesne further critiques the OCA's life extension forecast as the epitome of "speculative" projections by expert witnesses. It asserts that the OCA projections assume that current technology will continue to set market prices nearly 40 years from now, an assumption that is "somewhere between silly and reckless." (Duquesne Exc., citing St. 3-R at 22). Indeed, Duquesne states the OCA concedes that: "[i]*n reality, the* Company would defer life extension investment decisions until the years shortly before book retirement date[s] due to the inherent uncertainty of making such decisions this far

in advance." (Duquesne Exc. citing OCA St. 1 at 35-36). Duquesne concludes that there is no basis in fact for adopting these projections. (Duquesne Exc., p.16).

(iv) Resolution

On consideration of the Exceptions of the Company, we agree with Duquesne that in light of probable significant changes in technology over the remaining years of life of its plants, it would defer life extension investment decisions until the years shortly before book retirement dates due. This is due to the inherent uncertainty of making these decisions at the present time. Even though it is possible that some of Duquesne's plants may be life extended, this eventuality is uncertain, unknown, and unmeasurable at this time. We, therefore, reject the OCA's adjustment adopted by the ALJ. We decline to adopt the proposal for a $170.72 million adjustment to reflect an economic life extension for Duquesne's generating plants.

We further reject the OCA proposal as it is unclear from the record, given the age of the Duquesne units, that life extension is feasible. Finally, we find the OCA forecast additionally infirm as the costs associated with extending the life of the units for 15 years have not been included in its analysis.

(b) Plant Shutdowns

(i) Position of the Parties

The Company noted that several witnesses suggested that Duquesne should permanently shut down certain of its generating stations. The issue arises because, under Mr. Schnitzer's market price forecast, some of Duquesne's units were determined to have

"negative" operating margins, i.e., they receive less revenue than it costs to operate them. Duquesne pointed out that while this fact intuitively supports a shut down decision, it is not a complete analysis.

Duquesne witnesses argued that there may be unavoidable costs (e.g., property taxes and labor costs), that Duquesne will incur even if the plants are shut down. In any event, Duquesne committed to file a detailed study regarding potential plant closures in 1998 and allow "the Commission [to] make the determination of whether any units should be shut down." (R.D., p. 283).

The OCA noted in its direct case that Duquesne set the market value of generating facilities to $0 (excluding decommissioning), if the plant could not provide any net operating margins over the life of the plant. Consistent with this approach, the OCA's witness's stranded cost analysis produced a $0 market value for all of the Company's nuclear plants and several of the coal plants. For purposes of determining costs that would be "stranded" as of January 1, 1999, the OCA stated that it makes no sense to include future operating losses that have not been incurred and indeed will not be incurred in any reasonable economic scenario. (R.D., p. 284).

The OCA did not recommend the retirement of any generating units, especially in the absence of an analysis of the economics of doing so. However, it noted Duquesne's failure to address these operating losses prior to its Rebuttal case and Duquesne's failure to study its ability to reduce or avoid these operating losses is problematic in evaluating the Company's stranded cost claim and its rate cap plan. The OCA stated that Duquesne did not contest the accuracy of this evidence, but rather asserted that "there is not adequate time to investigate" it. (R.D., p. 283).

On the basis of the foregoing, the OCA submitted its approach of setting the plant margins of these units to $0 (excluding decommissioning) is reasonable and should be adopted.

The City noted Duquesne's plan does not call for shutting down uneconomic power plants in an effort to mitigate stranded costs, even in instances where to do so would save its customers hundreds of millions of dollars. The City argued that Duquesne's proposal to provide a 1998 shutdown study indicates Duquesne's acceptance of the criticism that it has ignored its duty to mitigate stranded costs by previously conducting such a study. It observes that shutdown issues should have been addressed in Duquesne's plan and not been put off to be the subject of a later study proposed in rebuttal testimony. This observation again speaks volumes about Duquesne's motives and the anti-competitive mind set of its management, states the City. (R.D., p. 286).

HSS/ARI argued that several of Duquesne's facilities, i.e., the Elrama, Brunot Island and Perry Units, should be retired immediately. The effect of those retirements would be a further reduction to Duquesne's stranded cost claim. (R.D., p. 286).

(ii) ALJ's Recommendation

The ALJ agreed with the Company and the OCA that there is inadequate time in this proceeding to investigate the feasibility of shutting down any of Duquesne's power plants. Therefore, the ALJ urged the Commission to adopt Duquesne's commitment to file a detailed study regarding potential plant closures by December 31, 1998, and, thereafter, allow the Commission to determine whether any units should be shut down.

(iii) Resolution

The Commission is not convinced that the submission of a plant shutdown study at this time would be a valuable work product. It would be immaterial if Duquesne is to proceed with divestiture. In the event of the merger, we are constrained to this case record for a determination of stranded costs. Such information provided at the end of 1998, could not be used to raise or lower a determination of stranded costs. Therefore, we find no useful purpose would be served by requiring the Company to undertake such a study.

(c) Productivity Gains

(i) Position of the Parties

The OCA proposed to increase the market value of Duquesne's plants by $13 million to reflect estimated "productivity gains." (R.D., p. 287). HSS proposed that, in setting any CTC, the Commission should assume cuts in operating and capital expenditures of between 10% and 20%. (R.D., p. 287).

Duquesne urged the rejection of each proposal arguing that they were not based on any study of the efficiencies that could be achieved given Duquesne's particular assets and work force. Also, Duquesne stated each proposal avoided addressing the significant cost savings and operating improvements already made by the Company and the further savings ($25 million annually) projected for the future. Additionally, each failed to consider the additional savings ($500 million on a nominal basis) that Duquesne expects to achieve through the merger. (R.D., pp. 287-288).

The OCA pointed out that Duquesne, in developing the market value of generating units, developed budget figures for non-fuel O&M expense for the transition period and escalated those at the Company's assumed rate of inflation of 2.5%. (R.D., p. 288 citing OCA St. 1, p. 33). Duquesne also escalated its A&G costs assigned to generating units and escalated them at its general inflation rate of 2.5%.

Based on the escalation of the above-referenced costs, the OCA maintained that the transition to a competitive environment will also result in productivity gains, reducing both the Company's non-fuel O&M and its A&G costs. (R.D., p. 288).

OCA witness Kahal explained "...one of the primary reasons of moving from a system of regulated monopoly, subject to cost-plus pricing, to competition is the belief that competition will motivate new efficiencies and cost control benefits not attainable under regulation." (R.D., p. 288 citing OCA St. 1, p. 29).

OCA proposed that there should be additional efficiency gains after the first few years of retail competition. Specifically, the OCA's witness Mr. Kahal estimated a 1.0% per year gain in productivity, beginning in the year 2003 and extending for ten years, with the savings capped at 10% and held constant over the remainder of the study period. Mr. Kahal supported his estimates with detailed citation to the analysis of the Staff of the FERC, which conducted an analysis of utility industry efficiency gains resulting from the introduction of wholesale competition from transmission access and also relied on a recent study conducted by the U.S. DOE which provided projections of the rate impacts associated with the introduction of retail access nationwide. (R.D., p. 289, n. 89).

The OCA's witness Kahal applied the productivity adjustment to Duquesne's non-fuel O&M and A&G expense for those plants with positive plant margins. Thus, the analysis resulted in savings capped at approximately 10% in 2012, which are held constant over the remainder of the study period. See OCA Schedule MIK-6. As noted by the ALJ, the result of the adjustment is not a decrease in expenses, but an increase in such expenses of 1.0% less than the general inflation rate used in the analysis. On the basis of the Kahal schedule, plant margins increased as of January 1, 1999, by approximately $13.04 million. (R.D., p. 290, citing OCA St. 1-S, p. 14; OCA M.B. at 43-44).

The OCA defended its efficiency adjustment as a conservative adjustment of 10% savings achieved over a ten-year period. This is in contrast to the observation of the FERC Staff and the Department of Energy of 15-25%, and 25-40% respectively. (R.D., p. 291).

In response to Duquesne's position that the OCA failed to consider the savings already achieved by the Company and savings expected to be achieved through the proposed merger, the OCA noted that the savings are those to be achieved in a competitive market. The OCA disagreed that the efficiencies created by the proposed merger are the same efficiencies that will be realized through competition. They are, stated the OCA, different and should be separately taken into consideration. OCA submits that its estimation of productivity savings, which simply reduces the annual rate of inflation in generation-related non-fuel O&M and A&G expenses by 1.0% for a ten-year period, is reasonable and should be adopted. (R.D., p. 291).

The City argued Duquesne's projections assume "fixed technology" and even Duquesne admits that a "fixed technology" estimate is inaccurate. The City states that Duquesne erroneously assumed that competitive pressures will not result in technological innovation, efficiency and productivity gains. Competition, observes the City, will motivate new efficiencies and could provide millions of dollars in cost savings. Finally, notes the City, Duquesne has more room than its competitors to reduce costs since Duquesne had the lowest relative efficiency of utilities studied in Pennsylvania, in the ECAR region, and the third lowest of utilities studied in the nation. (R.D., p. 292).

The PRA held the view that productivity is the central tenet of a competitive environment. It notes that this was a major rationale for injection of competition into the retail electric generation market. The PRA notes that a productivity gain has not been reflected by Duquesne in its stranded cost analysis. The PRA agrees with the OCA that utility operating costs should be reduced as competition is introduced in the retail generation market. This should include fuel costs, non-fuel, O&M, Administrative and General expenses and even possibly capital additions needed to maintain units and life extensions. Therefore, the PRA agrees that the OCA has assumed reasonably a productivity gain beginning in 2003 and extending for ten years thereafter. (R.D., p. 293).

(ii) ALJ's Recommendation

The ALJ was of the opinion that insufficient evidence exists in this record to support a productivity gain adjustment to Duquesne's generation related stranded costs. Therefore, he urged the Commission to reject it. (R.D., p. 294).

(iii) Parties' Exceptions

The OCA excepted to the ALJ's rejection of its productivity adjustment. The OCA submits that the industry experts and analysts expect that generating plant productivity will increase as a result of the introduction of competition into the generation marketplace. The OCA further submits that this is one of the primary reasons for moving from a system of regulated monopoly to a competitive market. Estimates have been made that fixed O&M costs of generating plants will be reduced from between 15% to 40% on an industry-wide basis, based on estimates made by the FERC and the U.S. Department of Energy (DOE). (R.D. p. 291).

(iv) Resolution

On consideration of the positions of the parties, we agree with the OCA that the transition to a competitive environment will result in productivity gains, reducing both Duquesne's non-fuel O&M and its A&G costs. Consistent with the observations of the OCA's witness Kahal, one of the primary reasons of moving from a system of regulated monopoly, subject to cost plus pricing, to competition, is the belief that competition will motivate new efficiencies and cost control benefits not attainable under regulation. Moreover, such efficiencies are not merely a one-time or episodic effort at cost control, but will be continual. Once deregulated, the owners of generation assets will, as a result of market pressures, seek ways of controlling costs and improving productivity on a ongoing basis. Therefore, we find the OCA's efficiency adjustment to be conservative, and based on demonstrated efficiencies and productivity gains resulting from the introduction of competition in the wholesale market. The studies of the FERC Staff and DOE show productivity levels in excess of the modest 1% per year gain in productivity

beginning in 2003 and extending for ten years, (capped at 10% and held constant over the remainder of the study period) proposed by the OCA.

Also, we reject the Company's reliance on post-restructuring mitigation as the sole indicator of the efficiencies and productivity gains that inure to the new, competitive regime.

Accordingly, we conclude that the OCA has demonstrated that it is reasonable to expect Duquesne's generating units to improve their productivity. Hence, we shall accept the OCA productivity gain as part of the market value calculation and reverse the ALJ's recommendation. The Exceptions of the OCA are granted consistent herewith.

(d) Costs Independent of Operation

(i) Position of the Parties

Duquesne explained that its claim for "Costs Independent of Operation" represent costs that are unavoidable if a generating unit is shut down. Duquesne stated that these costs, such as nuclear decommissioning, cannot be avoided by shutting down a nuclear plant. In some instances, Duquesne noted, the costs increase (on a net present value basis) the sooner a plant is shut down. (R.D. p. 294). For illustrative purposes, ALJ Corbett references two additional categories of costs, property taxes and administrative and general costs..

The OTS opposed Duquesne's claim. It referenced the OCA's witness Mr. Kahal's testimony that the claim assumed the Company should incorporate negative

market values for generating units - a change from the Company's direct case where negative market values (except decommissioning) were set to zero. (R.D., p. 295).

The OCA further contested the claim. The OCA objected that the Company's failure to identify these cost in its direct case given the Company's final valuation proposal prevented other parties from assessing their validity.[18]

The OCA also noted the Company initially assumed that plants with a net negative plant margin at January 1, 2006 would have a zero dollar market value. In its Rebuttal testimony, the Company modified this position, and in its analysis of stranded costs at January 1, 1999, has included a claim of $208.23 million for "Costs Independent of Operation" which are essentially the net[19] "unavoidable costs" associated with the operation of plants that produce net negative margins in the Company's analysis.

DII took no position on the propriety of allowing the Company to recover these alleged costs independent of operation; yet, DII expresses the concern that such costs were not identified in the Duquesne direct case.

(ii) ALJ's Recommendation

ALJ Corbett concluded that sufficient evidence existed in this record to support the Company's claim for Costs Independent of Operation. Therefore, he

[18] The OCA further observed that no other utility in Pennsylvania has presented a stranded cost claim for "Costs Independent of Operation." (R.D., p. 297 citing OCA R.B., p. 12).

[19] These are "net" unavoidable costs because the Company's analysis indicates that for Perry, Beaver Valley 2, and Elrama, continued operation will produce plant margins which are sufficient to cover avoidable costs and provide some offset to these unavoidable costs.

recommended its approval. However, the ALJ did not offer any reasoning or justification for his conclusion. (R.D. p. 298).

(iii) Parties' Exceptions

The OCA excepted to the ALJ's recommendation. (OCA Exc. p.11). The OCA finds objectionable, the fact that this claim was presented for the first time in Rebuttal Testimony.

The OCA submits that the assumption that there are substantial continuing costs associated with plants that provide no economic benefit is an irrational and inappropriate assumption to make in determining stranded costs. The OCA contends that the stranded costs associated with generating plants that have no economic value should be limited to the book value of the plant and should not extend to the general operating costs of the utility.

Finally, the OCA submits that a large claim such as the Duquesne's claim for costs independent of operation should have been accompanied by a detailed study of the ability to mitigate such costs and, in the absence of such an analysis, such a novel claim should be rejected.

The OTS also filed Exceptions. Again, it concurred with the OCA, that the aforementioned $208 million claim should be rejected.. At a minimum, argued the OTS, Duquesne should not be permitted to recover this claim if the merger is not consummated but a market based valuation option provided by the Company is exercised. (OTS Exc., p.7).

DII, in its Exceptions, submits that the Company's failure to fully state its claim for the $208 million for these costs in its case-in-chief prevents the proper recovery of these costs in this proceeding. DII respectfully requests that the R.D. be modified to deny recovery for "Costs of Independent Operation." (DII Exc., p.7).

(iv) Resolution

We shall reverse the ALJ's recommendation on this claim. We conclude that compensation to the Company for costs stranded, independent of operations, has not been adequately supported in this record. Duquesne does not propose any plant shutdowns. Therefore, no costs independent of operation exist. We agree with the comments of the OCA in its Exceptions that:

> "The assumption that there are substantial continuing costs associated with plants that provide no economic benefit is an irrational and inappropriate assumption to make in determining stranded costs. The stranded costs associated with generating plants that have no economic value should be limited to the book value of the plant and should not extend to the general operating costs of the utility".

(OCA Exc., p. 12).

We concur with the OCA that it is not rational to assume that absent a shutdown there are continuing costs associated with plants which have already been included in our determination of the permitted level of stranded costs.

Moreover, it is apparent that this claim only becomes operable if a unit is shut down, as these are continuing costs for the property absent energy production. These costs, in that event, would offset the removal of the plant values from the analysis. This

adjustment to stranded costs is unnecessary for our purposes since no shutdown is ordered, and would only be accounted for should a future shutdown be authorized.

Based on the foregoing, we shall grant the Exceptions of the OCA and reverse the ALJ.

(e) Projected Capital Additions and O&M Expense

(i) Positions of the Parties

HSS/ARI submitted a proposal regarding an "assumed" level of O&M or capital expenditure reductions. (R.D., p. 299).

HSS/ARI asserted in considering Duquesne's stranded cost claim that, 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. As a result, as previously indicated, HSS/ARI examined Duquesne's costs, as well as its price, projections. In doing so, it identified two significant instances in which Duquesne overstated its projected costs, thus unreasonably inflating its stranded cost claim.

The first of those two instances concerned Duquesne's projections of generation-related capital additions. As HSS/ARI 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. Moreover, Duquesne's rate proposal implicitly relies upon the capital additions through 2005. 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. Duquesne estimated that it would construct capital additions at a cost of $352 million from 1997 to 2005. 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. (R.D., p. 300).

Duquesne's projected O&M expenses also should be reduced. That reduction is warranted for several reasons. HSS/ARI compared Duquesne's historic production costs to those of other utilities in ECAR, as well as in Pennsylvania, using data from benchmarking studies performed by Standard & Poor's Rating Information Services. HSS/ARI also reviewed similar benchmarking studies commissioned by Duquesne 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. (R.D., p. 301). HSS/ARI contends that there are no grounds that support ratepayers' continued subsidization of Duquesne's inefficiencies. Accordingly, HSS/ARI proposed that the Commission should reduce Duquesne's O&M expenses by 15%.

(ii) Recommendation of the ALJ

The ALJ concluded that insufficient evidence existed in this record to substantiate the proposals of the HSS/ARI relating to projected capital additions and O&M expense. Therefore, he urged the Commission to reject them.

(iii) Parties' Exceptions

HSS/ARI excepted to the ALJ's recommendation.

First, HSS/ARI states that with respect to Duquesne's projections of capital additions, it produced the Company's own "Corporate Budget Variance Reports" which indicate that on average, from 1987 through 1996, Duquesne's actual generation-related capital expenditures were 17% lower than its projected expenditures for the next twelve months. (HSS/ARI St. No. 1 at 60; Exh. RBW-21). Thus, the data submitted by HSS/ARI with respect to Duquesne's projected capital expenditures, i.e., data showing a history of over-budgeting, are exactly the type of data the Commission relied upon in PECO Energy to order a disallowance.

Given that the Corporate Budget Variance Reports submitted here are Duquesne's own records, and Duquesne never challenged HSS/ARI's statements concerning those data, they argue it is implausible that the Commission could determine, in view of its ruling in PECO Energy, that the evidence here is insufficient. Accordingly, consistent with the ruling in PECO Energy, HSS/ARI submit that Duquesne's forecasted capital additions should be reduced by 20% to reflect its past, documented history of overbudgeting.

They further argue that the Commission also should reduce Duquesne's forecast of O&M expenses. With respect to those expenses, HSS/ARI take the position that they showed that Duquesne's production and operation expenses fall short of industry standards in numerous categories and that Duquesne's forecast of O&M expenses is inconsistent with its corporate strategy to reduce costs. (HSS/ARI, Exc., p.11).

HSS/ARI submit that Duquesne should be taken at its word, *i.e.*, that it is attempting to streamline its operations to compete in the new competitive environment. Accordingly, HSS/ARI recommended that Duquesne's O&M expense projections be reduced by 15%. (HSS/ARI, Exc., p.13).

(iv) Resolution

On consideration of the position of HSS/ARI, we concur with the ALJ in this area. We, therefore, accept his recommendation rejecting the HSS/ARI adjustment as unsupported by sufficient evidence.

Specifically, although HSS/ARI contend that Duquesne significantly over budgeted its capital addition and O&M expenses, HSS/ARI fail to identify a single expenditure since the last base rate proceeding as unreasonable. Additionally, HSS argued that all transmission and generation related capital additions that were made since the last rate case should be disallowed, or should be approved only in part, because Duquesne did not meet its "burden of proof" on these issues. (HSS Exc. pp. 6-10, 13,16, 26-27). We find these claims are without merit because they confuse the issue of a utility's "burden of proof" with the issue of an intervenor's burden of going forward with "credible evidence" to contest the reasonableness of particular cost items.

Based on the foregoing, we deny the Exceptions of HSS/ARI.

(f) Environmental Regulations

(I) Positions of Parties

Duquesne stated that all the market price forecasts in this case ignore two recent proposals that, if implemented, would add significant costs to operating Duquesne's generation. The first Duquesne claim is the EPA State Implementation Plan ("SIP call"), which would add more than $100 million in capital and O&M expense to Duquesne's fossil units. The second Duquesne claims is the recent Kyoto conference, where the participating nations agreed to significantly reduce CO_2 emissions. While it is not possible to quantify precisely the impact of such proposals on Duquesne's generation costs, it argues the Commission should recognize that all of the market value estimates are conservative in not taking into account the cost impact of these potential regulations. (R.D., p. 302). However, the OCA noted the impact of environmental regulations is included in the context of its market valuation forecasts, discussed supra. (R.D., p. 302).

DII alleged that the Company failed to challenge DII's market price projection on this point. Because of this alleged failure, DII said it is misleading to assume the DII projection does not address environmental regulations. Second, the Kyoto Accords on CO_2 emissions must be adopted by the U.S. Senate to become effective. Duquesne's witness expresses doubt that the treaty will be passed. Even if it were passed, Duquesne suggests that "at this point, it is impossible to say what those impacts will be." (R.D., p. 303).

(ii) ALJ's Recommendation

Since the ALJ recommended that the OCA's market value study be adopted, which adjusts for the impact of the known environmental regulations, he concluded no further adjustment should be allowed. He also determined that no substantial evidence exists in this record to substantiate any adjustment for the impact of the recent Kyoto conference. Accordingly, the ALJ urged the Commission to reject Duquesne's proposal to further adjust its stranded costs to reflect the impact of environmental regulations. (R.D., p. 303).

(iii) Parties' Exceptions

Duquesne excepted to the ALJ's failure to make an adjustment for the impacts of two environmental proposals that, if implemented, would add significantly to Duquesne's operating costs. (R.D., p.302).

(iv) Resolution

We agree with the ALJ's recommendation that the OCA's market value study resolves the environmental issue. The OCA's study adjusts for the impact of known environmental regulations. Thus, no further adjustment is offered and no adjustment should be allowed. At the same time, we reject Duquesne's proposal to further adjust stranded costs.

4. Summary

On consideration of the Exceptions of the Company, we agree with Duquesne that in light of probable significant changes in technology over the remaining

years of life of its plants, it would defer life extension investment decisions until the years shortly before book retirement dates due. This is due to the inherent uncertainty of making these decisions at present time. Even though it is possible that some of Duquesne's plants may be life extended, this eventuality is uncertain, unknown, and unmeasurable at this time.

We, therefore, reject the OCA's adjustment, as recommended by the ALJ. We decline to adopt the proposal for a $170.72 million adjustment to reflect an economic life extension for Duquesne's generation plants. We further reject the OCA proposal as it is unclear from the record, given the age of the Duquesne units, that life extension is feasible. Finally, we find the OCA's forecast additionally infirm as the costs associated with extending the life of the units for 15 years have not been included in its analysis.

In regard to plant shutdown studies, we are not convinced that the submission of a plant shutdown study at this time would be a valuable work product. It would be immaterial if Duquesne is to proceed with divestiture. In the event of the merger, we are constrained to this case record for a determination of stranded costs. Such information provided at the end of 1998 could not be used to raise or lower a determination of stranded costs. Therefore, we find no useful purpose would be served requiring the Company to undertake such a study.

We conclude that the OCA has demonstrated that it is reasonable to expect Duquesne's generating units to improve their productivity. Hence, we shall accept the OCA's productivity gain as part of the market value calculation and reverse the ALJ's recommendation. The Exceptions of the OCA are granted consistent herewith.

We conclude that compensation to the Company for costs stranded, independent of operations, has not been adequately supported in this record. Duquesne does not propose any plant shutdowns. Therefore, no costs independent of operations exist. We, therefore, shall reverse the ALJ's recommendation on this claim.

Although HSS/ARI contend that Duquesne significantly over budgeted its capital addition and O&M expenses, HSS/ARI fail to identify a single expenditure since the last base rate proceeding as unreasonable. We, therefore, accept his recommendation rejecting the HSS/ARI adjustment as unsupported by sufficient evidence.

We agree with the ALJ's recommendation that the OCA market value study resolves the environmental issue. The OCA study adjusts for the impact of known environmental regulations. Thus, no further adjustment is offered and no adjustment should be allowed. At this time, we reject Duquesne's proposal to further adjust stranded costs.

C. Merger Savings

1. Positions of the Parties

Duquesne proposed that any issues regarding merger-related synergies are appropriately addressed in the merger docket, not this proceeding. (R.D., p. 305). The OCA and MAPSA disagreed and indicated that merger savings from the stranded cost study should not be totally omitted from this proceeding (R.D., pp. 305, 308). The OCA suggested that we should consider stranded costs with and without merger savings. (R.D., p. 306). MAPSA added that since the restructuring proceeding and merger proceeding

are inextricably intertwined, we should render a decision in this proceeding based on an assumption that the merger is likely to occur. (R.D., p. 308).

The OCA recommended approval of $152.28 million of estimated generation-related merger savings at January 1, 1999, on an after tax basis and net of costs to achieve the savings. DII supported the OCA's position with respect to Duquesne's claimed savings that will result upon approval of the proposed merger (R.D., p. 306). Duquesne has not reflected merger savings in its computation of stranded costs, but stated instead, that the issue be addressed in the context of the merger proceeding (R.D., pp. 305-306). HSS/ARI indicated that, in the event of merger consummation, we should recognize the resulting cost savings and use the projected $550 million costs savings to offset any allowed stranded costs. PRA stated that stranded investment analysis must quantify savings if we approve or reject the proposed merger (R.D., pp. 307-308).

2. ALJ's Recommendation

ALJ Corbett agreed with MAPSA that this restructuring proceeding and the merger proceeding are inextricably intertwined. Under the ALJ's decision, an adjustment must be made in this case to account for the savings due to synergies that the Company admits will be achieved if the merger is successfully consummated. ALJ Corbett also recommended that we adopt the OCA's position (R.D., pp. 310-311).

3. Parties' Exceptions

Duquesne disagrees with the ALJ's recommendation and argues that any issues regarding merger related synergies are appropriately addressed in the merger docket, not in this proceeding (Duquesne Exc., p.17). The OCA argues that Duquesne's

stranded costs should be adjusted downward by $152.8 million if the merger is approved. (OCA R.Exc., p. 10). The DII submits that Duquesne's Exception to the ALJ's adjustment should be rejected. (DII R. Exc., p. 11). The HSS/ARI argue that Duquesne's attempt to shield merger savings from its ratepayers should be rejected. (HSS/ARI R. Exc., pp. 13-14).

4. Resolution

We note that this portion of the Recommended Decision provides guidance to conditions applicable if the merger goes forward and is successfully consummated. Consequently, we adopt Duquesne's presentation of the merger savings of $152.28 million as an offset to the recoverable stranded costs. We conclude that the OCA's recommendation in this regard is persuasive and supports our adoption of the merger savings adjustments.

Because the outcome of the proposed merger will not be known until after the record in this proceeding is closed, we find that it is improper to totally omit merger savings from the stranded cost study. Fairness and equity require that any merger savings should be credited against any stranded cost recovery authorized in this proceeding. In addition, we note the OCA's estimate of merger-related savings adopted Duquesne's own projections. Duquesne did not rebut the estimate other than to argue that such savings could be addressed in the final valuation.

The OCA also proposed an immediate rate reduction of $15 million to begin January 1, 1999, to reflect Duquesne's statement of merger savings associated with distribution operations. Duquesne had proposed that the rate reduction occur in the year 2001, to reflect distribution expense reductions. We agree with Duquesne that some time

must pass before such savings can be generated by the restructuring attendant to the merger. The record reflects, however, that both companies have been working to create these savings since the merger was announced last year. Merger savings from distribution revenues is one item that benefits all customers whether they shop for generation or not. This is a strong indicator of the benefits gained from a merger.

As a result, we conclude that the customer rate reductions should begin January 1, 2000, rather than in 2001, as the Company proposed. The reduction of $15 million in distribution revenues as proposed by the OCA is reasonable and is in the public interest because such savings from distribution revenues will benefit all customers even if they do not shop for generation.

D. Decommissioning

1. Nuclear Decommissioning

a. Positions of the Parties

The OTS noted that Duquesne claimed a share of the decommissioning responsibility for the Beaver Valley 1 and 2 and the Perry nuclear sites in its stranded cost claim. Duquesne's estimate for the decommissioning of Beaver Valley 1 and 2 is $727.7 million and its estimate for Perry is $650 million, for a total of approximately $1,378 million (1997$). The OTS disagreed with Duquesne's $1,378 million estimate. The OTS specifically opposed the use of contingency factors because the Act claimed that stranded costs must be "known and measurable." The effect of removal of the contingency factors from Duquesne's total nuclear decommissioning estimate is a reduction of $222.9 million. (R.D., pp. 313-315).

The OCA recommended modifications to Duquesne's nuclear decommissioning claim by calculating the annual funding contributions which are required over the years 1999 to 2005 to fully fund nuclear decommissioning costs prior to December 31, 2005. The OCA identified total funding requirements to fully fund nuclear decommissioning for Perry, Beaver Valley 1 & Beaver Valley 2 to be $7,949,000 per year for the seven-year CTC recovery period. (R.D., pp. 319-320).

The DII argued that Duquesne's claim of $281.0 million for nuclear decommissioning costs is inflated because it is not valued on a NPV basis. The DII recommended that we accept $42.959 million as the NPV of stranded nuclear decommissioning costs at December 31, 1998. The DII opposed Duquesne's proposal to calculate nuclear decommissioning costs as of December 31, 2005. (R.D., pp. 321-322).

The HSS/ARI contended that we should not reach a determination today concerning nuclear decommissioning costs that are not known and measurable and which Duquesne has not shown as stranded. HSS/ARI recommended that we reject Duquesne's request for $57.4 million in alleged nuclear decommissioning costs. As an alternative, The HSS/ARI suggested that we retain an independent expert in the field to perform an audit on Duquesne's nuclear decommissioning costs. (R.D., pp. 325-326).

The PRA asserted that we should permit a nuclear decommissioning cost recovery level of $42.959 million on a net present value basis for Duquesne's nuclear plants. The PRA argued that nuclear decommissioning costs must be valued at January 1, 1998, and not the final valuation date requested by Duquesne. (R.D., p. 328).

The Environmentalists urged us to address the complicated and technical policy issues of nuclear decommissioning in a generic case. (R.D., p.333).

b. ALJ's Recommendation

ALJ Corbett recommended that we adopt the OCA's proposed adjustment to Duquesne's claim for nuclear decommissioning costs. (R.D., p. 335).

c. Parties' Exceptions

The Environmentalists argue that the ALJ erred in rejecting its nuclear decommissioning proposals which included an incentive to control costs, the need for mitigation of decommissioning costs, the need for a generic proceeding on nuclear decommissioning, the need for an external fund, the need for cost-benefit analysis, and the proper treatment of spent nuclear fuel and radioactive waste. (Environmentalists Exc., p. 3).

Duquesne claims that the ALJ erred in adopting the OCA's proposal for nuclear decommissioning which used a contingency factor of 10%. (Duquesne Exc., p. 18). The OTS agrees that the ALJ erred in allowing a 10 % contingency factor add-on to Duquesne's nuclear decommissioning estimates. (OTS Exc., p. 7). The OTS also claims that the ALJ erred in recommending that Duquesne be permitted to recover the OCA's total projected level of nuclear decommissioning expenses over the seven year transition period. (OTS Exc., p. 11).

d. Resolution

We adopt the DII calculations which are supported by substantial evidence and, are consistent with our decision in, Pa P.U.C. v. Pennsylvania Power & Light Company, 85 Pa. P.U.C. 306 (1995). In order to protect against over-valuation, we specifically find that nuclear decommissioning expenses must be valued at net present value as of December 31, 1998, as calculated by the DII. We find that the Company's proposal, which includes a 4% annual inflation factor up to the year of each plant's decommissioning, is improperly inflated due to the inclusion of contingency factors. Since the Act provides that claimed stranded costs must be "known and measurable, we therefore reject Duquesne's proposal to defer stranded cost valuation as of December 31, 2005.

The proposed use of the December 31, 2005 date for the net present value calculation of the Company is intrinsically linked to Duquesne's residual CTC method. The annual recalculation of stranded costs and the "final look" valuation in 2003 does not comply with the statute directive for a stranded cost determination as a result of this restructuring proceeding. Therefore, the net present value shall be determined as of December 31, 1998.

2. Fossil Decommissioning

a. Positions of the Parties

Duquesne estimated a future fossil decommissioning expense of $274.4 million and argues that the expense is recoverable as a stranded cost because it is based on the actual decommissioning study presented by Duquesne witness LaGuardia.

The OCA argued that Duquesne's estimated future fossil decommissioning costs are not properly included in the stranded cost calculation and are not recoverable in this proceeding. The OCA further noted that we rejected PECO's claim for prospective fossil decommissioning in its entirety. See PECO Energy at 91. (R.D., pp. 341-343).

The DII concurred with the OCA's position and indicated that future fossil decommissioning expenses are not recoverable as stranded costs under the Act. The DII also cited our rejection of PECO's recovery for prospective fossil decommissioning as a stranded cost pursuant to the Act. See PECO Energy at 91. (R.D., pp. 343-345). The HSS/ARI agreed with the OCA and the DII, and concluded that future or prospective fossil plant decommissioning expenses are not traditionally recognized in rates in this Commonwealth, nor do they satisfy the known and measurable standard test for recovery as stranded costs. (R.D., p. 346).

The PRA noted that we should reject Duquesne's proposal to recover prospective fossil fuel decommissioning costs as a stranded cost due to the speculative nature of such projections. (R.D., p. 347).

The OTS disagreed with Duquesne's $274 million estimate because it was improperly inflated due to the inclusion of a 15% contingency factor. The OTS claimed that the inclusion of contingency factors is inconsistent with the Competition Act which provided that stranded costs must be known and measurable. The OTS recommended a $41.6 million reduction for a total remaining decommissioning expense estimate of $232.8 million. (R.D., pp. 337-338).

b. ALJ's Recommendation

ALJ Corbett recommended that we reject Duquesne's claim for fossil fuel decommissioning costs in its entirety because PECO Energy controls the issue. (R.D., p. 347).

c. Parties' Exceptions

Duquesne argues that the ALJ erred by disallowing recovery of future fossil decommissioning expenses. (Duquesne Exc., p. 18). PECO claims that the ALJ erred in denying Duquesne's request regarding the recovery of future fossil decommissioning costs. (PECO Exc., p. 3).

d. Resolution

The definition of stranded costs in Section 2802 clearly includes non-nuclear plan decommissioning as a potentially recoverable stranded cost within the Commission's discretion pursuant to Section 2808(c)(3). However, Duquesne does not claim any present actual fossil decommissioning costs. Instead, Duquesne claims its current estimate of future fossil decommissioning costs.

Even if this Commission could assume that Duquesne witness Laguardia's current estimate of future fossil decommissioning expense was accurate and that fossil decommissioning would in fact occur at the time and expense scenarios assumed by Duquesne witness Laguardia, the record of the case would remain devoid of any evidence suggesting that Duquesne's claimed fossil decommissioning costs will be stranded. The sale of Ft. Martin at a price substantially above book value and the market valuation

evidence in this proceeding provides no basis for a finding that future fossil decommissioning costs will ever be stranded for any particular plant, let alone every one of Duquesne's fossil units. Without a demonstration that a cost will be stranded, surely there is no recoverable costs. Fossil plant decommissioning, if it occurs at all, will occur after the transition period has ended, and it is possible that Duquesne will no longer own the plant. Indeed, Duquesne has proposed, to divest all of its generating units, and the Commission herein accepts that proposal.

Similarly, nothing in the Act requires recovery of future fossil decommissioning costs that do not yet exist as plant operating expenses. Crucially, future decommissioning costs are completely different from other operating costs that are now in rates and are not quantified. There are also unlike the book value of a plant that is now in rates and form the basis for a stranded cost claim. Future fossil decommissioning costs by definition are not now in rates and are not known and measurable, unlike the other expenses or assets at issue in this case.

We agree with Duquesne that prospective fossil decommissioning assumptions are somewhat like life assumptions. Like life extensions, it is possible that fossil decommissioning may occur at some future date. However, we cannot agree with Duquesne's assertion that fossil decommissioning is certain to occur within any meaningful time horizon. It is no more certain that the life extension assumption that Duquesne strongly rejects as inherently unknown and unmeasurable. Future fossil decommissioning expense is not a known and measurable amount at this time, because decommissioning is not certain to occur at all, the amount and the timing of any expense is speculative, and the level of decommissioning required and residual use of the site are entirely unknown. Thus, like life extensions and future environmental compliance costs, we conclude that there is not substantial evidence to support a finding that Duquesne will

incur any known and measurable fossil decommissioning costs that would have been recoverable under traditional ratemaking but are not stranded.

Duquesne's argument that the LaGuardia study is adequate to support stranded cost recovery for future fossil decommissioning ignores the fact that future fossil decommissioning costs are not recoverable under traditional ratemaking. Future fossil decommissioning expenses are not like recoverable stranded future operating expenses such as depreciation or fuel expense that are included in current rates at a precise expense level or a normalized level pursuant to traditional ratemaking.

Under traditional ratemaking, fossil decommissioning expense may be recoverable when the cost is incurred for the actual retirement of a plant. Present fossil decommissioning expense could be included in rates pursuant to Penn Sheraton, and within the Commission's discretion to permit recovery under the Act. Both Penn Sheraton and long-standing Commission precedent, however, preclude a present determination of recovery of prospective, speculative decommissioning expense. In order to be recoverable under traditional regulation, the cost must be known and measurable and actually incurred. For example, the Commission explicitly rejected a PPL claim for future fossil decommissioning expense in its last rate case.

Fossil decommissioning expenses are also unlike nuclear decommissioning expenses. Nuclear decommissioning expenses are already included in rates, are required by federal law, are specifically required for stranded cost recovery under the Act, and are required for urgent public health and safety reasons. Future fossil plant decommissioning is neither federally mandated nor urgent for public health reasons, and is not required under the Act.

We conclude that Duquesne has not documented any known and measurable future fossil decommissioning expense that meets normal ratemaking standards, demonstrated that the costs would be recoverable under traditional regulation, demonstrated that the cost will in fact be stranded, or demonstrated that the costs will be non-mitigated. Duquesne's claim therefore does not meet the basic requirements for stranded cost recovery and must be rejected. For these reasons, as well as those articulated by the OCA, DII, PRA and HSS/ARI, we deny Duquesne's claim.

E. Regulatory Assets and Liabilities

1. SFAS 109 Deferred Taxes

(a) Positions of the Parties

Duquesne claimed $179 million, net of taxes, for SFAS deferred taxes. The Company, under its methodology proposed in the case, removed the SFAS No. 109 plant tax liability from the balance of "plant in service" and included it as a regulatory asset. (R.D., p. 348). The OCA argued that this framework must be adjusted to a net present value of $62.94 million. (R.D., p. 350).

The DII argued that the SFAS 109 is not properly claimable by Duquesne as a stranded regulatory asset. DII, however, submitted that SFAS 109 net plant should remain part of the net book value of the Perry and Beaver Valley 1 generating units and that Duquesne's claimed regulatory asset of $62.94 million be denied. (R.D., p. 352)

HSS/ARI opposed Duquesne's recovery of $179 million on a net present value basis. HSS/ARI noted that Duquesne's request conflicts with our ruling in PECO. PECO Order at 66. (R.D., p. 353).

PRA recommended that the amount of the SFAS 109 asset related to plant should be included in the Duquesne qualification of generation related costs only. (R.D., p. 354).

(b) ALJ's Recommendation

ALJ Corbett recommended that we approve the OCA's approach to avoid the "double recovery" problem. Accordingly, Duquesne's SFAS 109 obligation should be treated as a tax liability from the balance of plant in service and not as a regulatory asset. ALJ Corbett's recommendation reduces Duquesne's regulatory asset claim by $ 62.94 million. (R.D., p. 354).

(c) Parties' Exceptions

The HSS/ARI claims that the ALJ erred in approving Duquesne's claim for recovery of any SFAS 109 deferred taxes as a regulatory asset. HSS/ARI argues that since Duquesne did not file a rate case since 1986, it retained any tax benefits for its shareholders. (HSS/ARI Exc., pp. 20-21, R. Exc., p. 21).

(d) Resolution

We conclude that in order to be claimable as stranded costs, regulatory assets must be "known and measurable" and traditionally recoverable under current

regulatory practice but not recoverable in the competitive market. The Commission must quantify the amount of any properly claimed stranded regulatory asset on a net present value basis. Under its methodology proposed in the case, Duquesne removed SFAS No. 109 plant tax liability from the balance of plant in service and included it as a regulatory asset. While we do not dispute that this was necessary under the Company's approach to properly recover the SFAS 109 plant obligation, we conclude that the Companies adjustment must be reversed. We note the Company's final regulatory asset claim reflects the OCA adjustment of $62.94 million for SFAS 109 plant obligation, so no further adjustment is required.

We find that this SFAS 109 net plant regulatory asset is not properly claimable by Duquesne as a stranded regulatory asset. This particular asset contrasts to nuclear decommissioning expenses which are fully recoverable. The claimed SFAS 109 regulatory asset is not a "net generation-related" cost pursuant to the Act. Prior to claiming the regulatory asset, SFAS 109 net plant was included as "plant in service" for the Perry and Beaver Valley 1 units. In order to avoid the problem of double recovery, and allow for consistency in the application of the analysis of the recovery of stranded costs, we conclude that Duquesne's SFAS 109 obligation should be treated as a tax liability from the balance of plant in service and not as a regulatory asset. We, therefore, reduce the Company's regulatory asset claim by $62.94 million.

2. Unamortized Debt Costs

(a) Positions of the Parties

Duquesne claimed pre-2006 unamortized debt costs of $9.8 million and post-2005 debt costs of $19.04 million. (R.D., p. 354). The OCA, however,

recommended a different approach to the determination of stranded costs-specifically that a determination of stranded costs be made as of December 31, 1998. The OCA concluded that Duquesne's unamortized debt costs as of December 31, 1998 should be treated as a regulatory asset in the amount of $45.77 million. (R.D., p. 355-356).

The DII opposed Duquesne's recovery of unamortized debt costs because these costs are not "net electric generation-related costs" pursuant to the definition of stranded costs in the Act. The DII also noted that Duquesne admitted that the inclusion of these costs as regulatory assets and in its cost of debt conceptually represents double recovery. (R.D., p. 358-359).

The HSS/ARI and the PRA are opposed to Duquesne's request to recover unamortized debt costs and unamortized premium on reacquired debt as regulatory assets. HSS/ARI noted that 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. (R.D., pp. 360-361).

(b) ALJ's Recommendation

ALJ Corbett agreed with the OCA's claim for unamortized debt costs should be valued as of December 31, 1998. (R.D., p. 361).

(c) Parties' Exceptions

The DII contends that the ALJ inappropriately permitted Duquesne to recover its claimed regulatory asset for unamortized debt costs (DII Exc., p. 9). The

HSS/ARI adds that the ALJ erred in granting Duquesne's request for recovery of $47.77 million in unamortized debt costs as a regulatory asset (HSS/ARI Exc., p. 21).

(d) Resolution

We support the ALJ's recommendation which adopts the position of the OCA. The OCA concluded that Duquesne's unamortized debt costs as of December 31, 1998, should be treated as a regulatory asset in the amount of $45.77 million. As a result of this approach, we find that the full generation-related balance of unamortized debt costs as of December 31, 1998 should be recognized as a regulatory asset. We reject the arguments of the HSS/ARI and DII relative to improper Company claims of unamortized debt costs as a regulatory asset. The HSS/ARI and DII also claimed that Duquesne's request results in a double recovery. We concur with the OCA witness Catlin who considered unamortized debt as of December 31, 1998 as a regulatory asset (exclusive of unamortized debt costs associated with the Beaver Valley 2 sale/leaseback).

3. Unamortized Sale/Leaseback Premiums

(a) Positions of the Parties

The OCA noted that Duquesne claimed as a regulatory asset full recovery for the "premium of reacquired debt associated with Beaver Valley No. 2." The Company valued the regulatory asset at $30.06 million. The claimed regulatory asset is divided in two parts-pre 2005 and post 2005. OCA utilized a discount rate of 6.88% to determine the net present value of these costs and then removed $63.66 million to reflect the benefits of the Ft. Martin Agreement, resulting in a net present value amount of $55.13 million. (R.D., p. 362).

The DII recommended that we deny Duquesne's treatment of the Beaver Valley 2 sale/leaseback premium of $30.06 million. DII noted that because recovery for the refinancing premium will be provided from elsewhere both pre-2005 and post-2005, Duquesne's claimed regulatory asset for the Beaver Valley 2 sale/leaseback premium is not a "net" stranded regulatory asset pursuant to the Act. As a result, the DII contended that recovery should be denied. (R.D., p. 365). PRA noted that the effect of improper inclusion in both generation stranded cost quantification and as a regulatory asset is an excessive quantification of stranded costs. (R.D., p. 365).

(b) *ALJ's Recommendation*

ALJ Corbett recommended that we adopt the claim of Duquesne for unamortized sale and leaseback premiums, as modified by the OCA. (R.D., p. 366).

(c) Parties' Exceptions

There are no arguments on exception for this issue.

(d) Resolution

Consistent with the ALJ's recommendation, we adopt Duquesne's claim for unamortized sale and leaseback premiums as modified by the OCA treatment. We agree that the OCA's approach in determining a net present value of $55.13 million is reasonable and appropriate. We also agree with the OCA that Duquesne, for all practical purposes, is the owner of the Beaver Valley 2 nuclear generating station and treat all of the costs of the sale/leaseback as an owned-generation asset. We likewise concur with the

OCA's removal of $63.66 million to reflect the benefits of the Ft. Martin agreement. We note that Duquesne has no particular quarrel with the OCA's treatment.

4. Deferred Rate Synchronization Costs

(a) Positions of the Parties

Duquesne claimed deferred rate synchronization costs of $23.5 million. (R.D., p. 366). The OCA argued that the correct quantification, as agreed to by the Company, is $24.87 million (at December 31, 1998). (R.D., p. 367). HSS/ARI contended that Duquesne should not be permitted to recover its deferred rate synchronization costs as a regulatory asset in this proceeding (R.D., p. 368). PRA noted that under its proposal, Duquesne would amortize the unamortized balance by the end of the year 2005. PRA contended that this amount should be valued at the net present value amount as of December 31, 1998, over the remaining amortization period and not the nominal amount at December 31, 1998. (R.D., p. 370).

(b) ALJ's Recommendation

ALJ Corbett recommended that we permit recovery of $23.5 million, on a net present value basis for Duquesne's claim of $23.5 million for deferred rate synchronization costs. (R.D., p. 370).

(c) Parties' Exceptions

HSS/ARI argues that the ALJ erred in granting Duquesne's requested recovery of $23.5 million in deferred rate synchronization costs as a regulatory asset.

HSS/ARI contends that the ALJ's recommendation is inconsistent with PECO Energy. (HSS/ARI Exc., p. 22).

(d) Resolution

We adopt the ALJ recommendation which accepts the revised Duquesne claim. The ALJ specifically finds that the record supports the Duquesne claim, and we permit recovery of $23.5 million, on a net present value basis. Deferred rate synchronization costs are early window costs associated with Perry and Beaver Valley 2 that the Company is permitted to amortize through 2006, as part of the Ft. Martin settlement. Since a return on these costs in a regulated environment would not be recoverable, the deferred rate synchronization regulatory asset in this proceeding must be quantified on a net present value basis.

5. Deferred Employee Costs

(a) Positions of the Parties

Duquesne claimed deferred employee costs of $13.830 million, on a net present value basis. (R.D., p. 370). DII claimed the Company's stranded regulatory asset for deferred employee costs is inappropriate and must be rejected. DII submitted that Duquesne's claim that all regulatory assets simply represent timing differences between accrual and cash recognition of expenses is incorrect. PRA concurred with DII. (R.D., pp. 371-374).

(b) ALJ's Recommendation

ALJ Corbett recommended that Duquesne's claim for deferred employee costs of $13.830 million, on a net present value basis appears justified and should be approved. (R.D. p. 374).

(c) Parties' Exceptions

DII argues that the ALJ erred in permitting Duquesne to recover a stranded regulatory asset for deferred employee costs. (DII Exc., p. 11). DII claimed that this is inappropriate under the Act since the costs are not rendered unrecoverable by the transition to a competitive market. (DII Exc., p. 12).

(d) Resolution

We adopt Duquesne's claim for compensated absences, injuries and damages of $14.24 million, as computed by the OCA, on a net present value basis, as supported by the ALJ. We believe that these costs are justified and should be approved. Since all regulatory assets represent the timing difference between accrual and cash recognition of expenses, the asset should be allowed. We note that similar regulatory assets were approved in PECO Energy.

6. Deferred Coal Costs

(a) Positions of the Parties

Duquesne claimed deferred coal costs in the amount of $13.5 million, on a net present value basis. (R.D., p. 374). The OCA recommended that Duquesne's entire deferred cost claim be denied because the Commission settlement at Docket Nos. P-00890386 and P-00890387 Slip Op. (June 15, 1990) did not provide assured recovery of any costs which the Company was required to defer because the price paid for coal exceeded the price cap. (R.D., p. 375). DII added that Duquesne's claim for a regulatory asset representing deferred coal costs is inappropriate under the Act because the amounts would not be typically recoverable in the regulated environment. (R.D., p. 377). HSS/ARI contended that since Duquesne cannot determine its future deferred coal costs on a net known and measurable basis, the Company's attempt to recover such costs must, therefore, be rejected. (R.D., p. 378). PRA also favored denial of Duquesne's claim because this amount represents costs which historically have been above market costs that limited the amounts that could be included in an annual ECR. (R.D., pp. 378-379).

(b) ALJ's Recommendation

ALJ Corbett recommended that Duquesne's claim for deferred coal costs of $13.5 million be denied in its entirety. (R.D., p. 379).

(c) Parties' Exceptions

Duquesne claims coal costs that exceeded "caps" in the Company's ECR and were deferred for recovery until fuel costs fell below those caps in the amount of

$13.5 million, on a net present value. The Company argues that the ALJ's finding is based on the argument that the caps were "market" based and that Duquesne's fuel cost will never fall below market levels, when, in fact, the caps at issue are cost-based, and Duquesne's fuel costs will decline in 2000 to below these. (Duquesne Exc., p. 19-20).

(d) Resolution

Duquesne claims deferred coal costs in the amount of $13.5 million, on a net present value basis. The balance represents the amount that Duquesne paid for coal from the Warwick mine or at the Mansfield plant in excess of the amount that it was permitted to roll-in through its ECR under the terms of the settlement reached by the parties in Petition of Duquesne Light Company for Order Establishing a New Coal Standard at Docket Nos. P-00880386 and P-00890387. Duquesne's witness O'Brien argued that the settlement provided for recovery of these deferred coal costs at some future time. The OCA's witness Catlin disagreed and recommended that Duquesne's entire deferred cost claim be denied. He argued that the settlement did not provide assured recovery of any costs which Duquesne was required to defer because the price paid for coal exceeded the price cap.

We adopt the ALJ's recommendation which disallows the Duquesne claim for deferred costs of $13.5 million in its entirety, finding that the Company has failed to show that these costs would be recoverable in a regulated environment. We likewise concur with the OCA's witness Catlin that the settlement at Docket Nos. P-00880386 and P-00890387 did not provide assured recovery of any costs which Duquesne was required to defer because the price paid for coal exceeded the price cap.

7. Deferred Caretaker Costs

(a) Positions of the Parties

Duquesne claimed deferred caretaker costs of $3.92 million, on a net present value basis, that are incurred in maintaining Brunot Island and Phillips plants in cold storage in the expectation that, in the future, they would become economic. (R.D., p. 379).

The OTS indicated that since Duquesne has clearly failed to meet its burden of proof that these costs are recoverable under the Act, the Company's claim should be denied. (R.D., p. 380). The OCA added that there is no basis that the recovery of deferred caretaker costs and the $6,770,000 on a pre-tax basis should be removed from Duquesne's regulatory asset claim. (R.D., p. 382). DII further contended that these costs do not meet the standards for recovery of stranded costs pursuant to the Act and should, therefore, be denied. (R.D., p. 383). HSS/ARI agreed with the DII and added that these caretaker costs are not related to industry restructuring and should be removed from Duquesne's stranded cost claims (R.D., p. 384). PRA also contended that Duquesne's claim should be disallowed because recovery would have been permitted only if the plants had been returned to service (R.D., p. 385).

(b) ALJ'S Recommendation

ALJ Corbett recommended that we deny Duquesne's claim for deferred caretaker costs of $3.92 million on a net present value basis in its entirety. ALJ Corbett noted that nothing in the record appears to support a determination that the assets

associated with these caretaker costs will be returned to service within the foreseeable future. (R.D., p. 385).

(c) Parties' Exceptions

Duquesne claims that the ALJ erred in disallowing deferred caretaker costs associated with Brunot Island and Phillips. (Duquesne Exc., p. 20).

(d) Resolution

The deferred caretaker cost regulatory asset reflects the accounting treatment authorized by the Commission at Docket No. P-00900485 for preservation costs associated with maintaining the Philips and Brunot Island Generating plants. Since Duquesne has stated that it has no intention to return these units to commercial operations, we conclude that recovery of the regulatory asset is inappropriate under the standards set forth in the Act. Regulatory assets are recoverable under the Act for specific reasons, including that they would be typically recoverable in a regulated environment and stranded as a result of the transition to a competitive market. Several commentators, including the OCA, OTS, DII, HSS/ARI, and PRA concur that Duquesne's claim should be rejected.

We adopt the ALJ recommendation which holds that the assets to which these costs relate, the Phillips and Brunot Island plants, are not "used and useful". We deny those costs of $3.92 million on a net present value basis in their entirety. We find that nothing in the record appears to support a determination that the assets associated with these caretaker costs will be returned to service within the foreseeable future.

8. Pre-Accrual of Nuclear Outages

(a) Positions of the Parties

Duquesne claimed a charge of $10.29 million, on a net present value basis, for pre-accrual of nuclear outages. (R.D., p. 385). The OCA opposed the charge because it feared that this will result in a double accounting of costs. (R.D., p. 387). DII added that the Company inappropriately requested recovery for a regulatory asset related to its change in the accounting treatment of costs associated with nuclear outages. DII claimed that these costs are not "stranded" pursuant to the Act because the accounting deferral will reverse in the final year of the nuclear unit's life. PRA supported DII on this issue. (R.D., pp. 387-388).

(b) ALJ's Recommendation

ALJ Corbett recommended that we allow Duquesne to claim as a regulatory asset pre-accrual of nuclear outages in the amount of $10.29 million on a net present value basis. ALJ Corbett noted that the transition to a competitive market justified a change in accounting methods for this asset. (R.D., pp. 388-389).

(c) Parties' Exceptions

DII claims that the ALJ erred in permitting Duquesne to recover a stranded regulatory asset for pre-accrued nuclear outage costs. (DII Exc., p. 12). DII notes that these costs will be recoverable in the competitive market and do not qualify under the Act's definition of stranded cost. (R.D., p. 13).

The OCA argues that the ALJ's decision to allow recovery of pre-accrued nuclear outage costs as a separate claim was in error (R.D., pp. 388-389). The OCA objects to including these costs as a regulatory asset because the costs were recovered elsewhere. (OCA Exc., pp. 21-22).

(d) Resolution

Duquesne claims a charge of $10.29 million, on a net present value basis, for pre-accrual of nuclear outages. This regulatory asset arises from a change in accounting that was specifically approved by Duquesne's outside auditors and FERC staff. The OCA opposes this change because it will result in double counting of costs. The OCA's witness Catlin stated that these outage costs are already included in the OCA's stranded cost analysis and, thus, would not deny Duquesne any recovery. DII added that the claimed regulatory asset is not stranded because Duquesne will recover the deferral amount regardless of the transition to the competitive market. Consequently, DII's claim that pre-accrued nuclear outage costs are not properly recoverable as a stranded cost pursuant to the Act.

For these reasons, we reject the ALJ's recommendation to allow Duquesne to claim as a regulatory asset pre-accrual of nuclear outages in the amount of $10.29 million, on a net present value basis. We concur with the OCA that this adjustment is included in plant operations and allowance as a regulatory asset would double count the expenses of a nuclear outage.

9. Transition Costs

(a) Positions of the Parties

Duquesne claimed transition costs of $10.59 million, on a net present value basis. (R.D., p. 389). The OTS and the OCA do not oppose this recovery because PECO Energy permitted recovery of similar costs. (R.D., p. 389). DII and HSS/ARI opposed part and all, respectively, of these costs, but they do not contest any expenditures as unjust or unreasonable. DII specifically requested that $8.3 million in Customer Advanced Reliability System (CARS) related expense be removed from the Company's proposed transition cost claim (R.D., pp. 390-391).

(b) ALJ's Recommendation

ALJ Corbett recommended that we allow the Company to claim the full amount of its transition expenses in the amount of $10.59 million, on a net present value basis. (R.D., p. 392).

(c) Resolution

We adopt the ALJ's recommendation to allow Duquesne the full claimed amount of transition expenses in the amount of $10.59 million on a net present value basis. We note that there is no support for DII's contention that Duquesne's claim included $8.3 million in Customer Advanced Reliability System (CARS) related expenses. We find that these transition costs, which relate to the expense of this restructuring proceeding and pilot program deferrals, should be approved because they

were required to be expended to implement the Act. We note that recovery of similar costs was permitted in PECO.

10. SFAS 106 Deferred Costs

(a) Positions of the Parties

Duquesne claimed $1.92 million, on a net present value basis, for SFAS 106 deferred costs. (R.D., p. 392). The OTS and the OCA do not oppose their recovery since PECO Energy approved recovery of a similar regulatory asset. (R.D., p. 392). The DII and HSS/ARI, however, opposed recovery. the DII argued that the Company's claimed regulatory asset for SFAS 106 costs lacked a factual and statutory basis. PRA concurred with DII. HSS/ARI added that Duquesne has not offered any support for our approval of these costs as a regulatory asset. (R.D., pp. 393-395).

(b) ALJ's Recommendation

ALJ Corbett recommended that we deny Duquesne's claim for $1.92 million, on a net present value basis. ALJ Corbett noted that SFAS 106 is not a regulatory asset and all suppliers in a competitive environment will be subject to SFAS 106. (R.D., p. 395).

(c) Parties' Exceptions

Duquesne excepts to the ALJ's disallowance of SFAS 106 health care benefits and life insurance for retired employees. (R.D., p. 395) (Duquesne Exc., p. 20). HSS/ARI argued that Duquesne's exception should be denied because the Company has

not been able to demonstrate that it is entitled to recover any SFAS 106 deferred costs. (HSS/ARI R. Exc., p. 19). The DII adds that Duquesne's exception is without merit and should be denied because the concept of stranded cost recovery is only available for the portion of future operating costs not compensated for by future market prices. (DII R. Exc., p. 13). PRA concurs that SFAS 106 costs are not transition costs. (PRA R. Exc., p. 6).

(d) Resolution

Duquesne claims $1.92 million, on a net present value basis, for SFAS 106 deferred costs related to post-retirement benefits such as health care and life insurance. Duquesne's witness Clayton stresses that these expenses are required under Generally Accepted Accounting Procedures (GAAP). The OCA and OTS support the recovery of these costs.

Since these costs are required under GAAP, are known and measurable, and incurred under traditional regulation, and otherwise meet the definition of stranded costs, we find that Duquesne's claim is justified. We, therefore, reject the ALJ's recommendation and adopt the Duquesne/OCA/OTS allowance of $1.92 million. We note that recovery of a similar asset was approved in PECO.

11. Warwick Mine Costs

(a) Positions of the Parties

Duquesne submitted a claim for over $15 million in stranded costs associated with the Warwick Mine. Duquesne explained that Warwick mine costs are

included in plant, not regulatory assets. (R.D., p. 396). No party other than HSS opposed its recovery. HSS/ARI argued that Duquesne is inappropriately seeking direct recovery of its capital investment in the mine from its ratepayers. (R.D., pp. 396-397).

(b) ALJ's Recommendation

ALJ Corbett recommended that we deny Duquesne's claim in its entirety since Warwick Mine costs are not currently in rate base and the costs are not stranded by the transition to a competitive generation market. (R.D., p. 397).

(c) Parties' Exceptions

Duquesne claims that the ALJ decision disallowing Warwick Mine costs is in error. The Company argues that the finding ignores the agreement reached with the Commission since the last rate case, under which Duquesne can recover the cost of the Warwick Mine through the ECR. (Petition of Duquesne Light Company for Order Establishing A New Coal Cost Standard, P-890386, Order 3) (Duquesne Exc., p. 21).

(d) Resolution

Duquesne seeks to recover over $15 million in claimed stranded costs associated with the Warwick Mine. The claimed $15 million represents the net book value of Duquesne's investment in the mine. In 1981, the Commission required Duquesne to remove Warwick Mine from the Company's rate base. After 1981, Duquesne was permitted to recover its investment in the Warwick Mine through the cost of coal subject to the coal cost cap in the ECR. In 1996, the operator of the mine ceased operations. HSS/ARI argues that for the same reason applicable to deferred coal costs as previously

discussed, Warwick Mine capital does not qualify as a regulatory asset. Also, 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 with, the mine under the coal cost cap.

We agree with the exceptions of Duquesne and reject the ALJ's adoption of the HSS position. The inclusion of the remaining plant balance in net plant in service is the proper treatment to be accorded this stranded property. We have disallowed the regulatory asset claim for deferred fuel costs associated with the past operation of the mine. The net plant is the cost that would have had rate recovery through the ECR absent the Act. Duquesne never sought treatment of the property as a regulatory asset as claimed by HSS.

F. Recovery of Stranded Costs

1. Proposals to Adjust the Level of Stranded Cost Recovery

(a) Mitigation

(i) Positions of the Parties

Duquesne noted that by the year 2005 its mitigation efforts will have achieved $1 billion in savings and $700 million in avoided rate increases. (R.D., p. 400). The OCA determined the reasonable level of the Company's owned-generation stranded costs at January 1, 1999, to be $1.020 billion.

The DII contended that we should strongly urge Duquesne to pursue securitization of stranded costs as a final mitigation strategy to arrive at a just and reasonable recovery from ratepayers. (R.D., p. 405). The HSS/ARI contended that the evidence fails to demonstrate that Duquesne in fact has any stranded costs. (R.D., p. 405). The PRA suggested that once stranded costs are quantified, we must determine the allowed level permitted for recovery from ratepayers. (R.D., p. 407).

(ii) ALJ's Recommendation

ALJ Corbett concluded that no substantial evidence exists in the record to justify any adjustment to the mitigation efforts already committed to be undertaken by the Company. (R.D., p. 409).

(iii) Parties' Exceptions

The Environmentalists argue that the ALJ erred in concluding that Duquesne's mitigation efforts were adequate. (Environmentalists Exc., p. 3). Mr. Hughes concurs with the Environmentalists. (Hughes Exc., p. 9). The PRA argues that certain of the stranded cost component disallowances in this proceeding are based upon a need to mitigate and those should be adopted by the Commission. (PRA Exc., p. 14).

(iv) Resolution

We adopt the ALJ's determination that Duquesne's past actions have been adequate, but the Company must also continue a commitment to mitigation. We are aware that Duquesne's mitigation efforts will have achieved $1 billion in savings and $700 million in avoided rate increases by 2005. Duquesne St. 1 at 20; Duquesne St. at

24-26. Additionally, Duquesne auctioned a generating plant prior to the Act and used the proceeds to increase the depreciation of nuclear assets. Duquesne St. 2 at 10-12; Duquesne St. 1-R at 21.

(b) Sharing of Stranded Costs

(i) Positions of the Parties

The OCA, DII and Environmentalists each recommend a "sharing" of stranded costs. The OCA argued that sharing is appropriate, consistent with the Act, and will not significantly impair the Company's financial integrity. (R.D., p. 413). The DII added that we should employ the equity return disallowance as a reasonable method to share stranded costs between shareholders and ratepayers. (R.D., p. 425). The PRA noted that the Act does not require 100% recovery of stranded costs. (R.D., p. 426). Environmentalists believe that stranded generating asset recovery should be no larger than needed to provide the shareholders with a return of their investment in Duquesne's generating plant and reasonable return on that investment. (R.D., pp. 431-432).

Duquesne opposed a recommended "sharing" of stranded costs because, in their view (1) there is no support in the Act; (2) the proposals are not consistent with historic regulation in Pennsylvania; (3) the proposals are arbitrary in that they bear no relation to the facts of this case; and (4) the proposals violate state and federal law. (R.D., pp. 409-412).

(ii) ALJ's Recommendation

ALJ Corbett recommended that we deny any proposal for stranded cost sharing. ALJ Corbett concluded that any "sharing" proposal conceptually can be viewed as a "taking" of assets, subject to constitutional due process constraints. (R.D., p. 432).

(iii) Parties' Exceptions

The DII contends that the ALJ erred in rejecting its proposal for sharing stranded costs between ratepayers and shareholders. (DII Exc., p. 13). The DII requests that we modify the ALJ's Recommended Decision on this issue and use the DII recommended equity return disallowance to equitably share stranded costs between ratepayers and shareholders. (DII Exc., p. 17).

The HSS/ARI argues that the ALJ erred in recommending that Duquesne be permitted to include in stranded costs expenditures that the Company has not shown are just and reasonable. (HSS/ARI Exc., p. 13). The Environmentalists also argue that the ALJ erred in denying a sharing of the stranded generating assets. (Environmentalists Exc., p. 3). The OCA adds that the ALJ erred in placing on ratepayers the full burden, including a full return on capital, of the company's uneconomic investments, especially its uneconomic investment in nuclear generating facilities. (OCA Exc., p. 13).

(iv) Resolution

We reject the ALJ's conclusion that the Act prohibits sharing of stranded costs and that any sharing amounts to a taking. To the contrary, we find that the Act contemplates the Commission's deliberation as to just and reasonable rates for recovery of stranded

costs. It is quite apparent that the Act does not restrict the Commission's deliberation. The fact that sharing is not explicitly detailed, was to provide the Commission with the full opportunity to customize the stranded cost result and recovery to the circumstances of the individual utility. We exercise our discretion to allow Duquesne to recover 100% of its stranded costs documented to exist in fact. We find that under the circumstances of this case, the authorized recoverable smount results in a just and reasonable balancing of complex, competing interests. See PECO Energy, pp. 100-101.

To require Duquesne to share the stranded generating assets would amount to denying it recovery of a portion of its proven, stranded costs which cannot be mitigated. In our December 23, 1997 Order, in PECO Energy, we held that full recovery of these costs was just and reasonable because it balances the interest of shareholders and ratepayers. PECO Energy at 100-01. This gives the utility a fair transition to full competition when stranded cost recovery expires and provides customers with adequate shopping credits, even while they are paying the CTC. At that time we stated:

> We are confident that allowing PECO full recovery of its actual stranded costs as determined in this proceeding will enable PECO to make an effective transition to competitive markets as required under the Act, while also establishing a vibrant competitive market with real economic opportunities for competitive suppliers and consumers.

Id. At 101. We continue to hold that belief and see no reason why, absent compelling evidence, one utility should be treated any differently than another utility within the Commonwealth.

(c) Securitization

(i) Positions of the Parties

Duquesne argued that the Act does not permit forced securitization and claims such requirements would be inappropriate. (R.D., pp. 432-433). DII argued that we should require Duquesne to securitize its authorized level of stranded cost recovery in this proceeding. They claim that the Act specifically recognizes the issuance of securitized debt as a proper mitigation effort by the Company in determining the level of stranded costs that an electric utility may recover through the CTC (R.D., p. 433).

(ii) ALJ's Recommendation

ALJ Corbett recommended that DII's securitization proposal be rejected because the unrebutted evidence disclosed that Duquesne has the highest degree of debt leverage in the state, thereby lowering the its cost of capital. (R.D., p. 436).

(iii) Parties' Exceptions

The Environmentalists contend that the ALJ erred in rejecting securitization as a strategy for mitigation of stranded cost. The Environmentalists contend that Duquesne should not be able to foreclose securitization as a mitigation strategy by giving preference to its other debt. (Environmentalists Exc., p. 4). DII also contends that the ALJ erred in rejecting its securitization proposal. DII believes that Duquesne should be directed to securitize its authorized level of stranded costs as a final step of mitigation to reduce the amount of stranded costs that must be recovered from taxpayers. (DII Exc., pp. 17-19).

(iv) Resolution

We conditionally adopt the ALJ's recommendation on this issue. We find that the Act provides that securitization may be proposed only by the Company. While Duquesne, as a stand alone company, does not believe that it can securitize within its sale/leaseback and financial covenants, the post merger company should examine the option for both operating territories and determine, after a fresh look, whether securitization can provide benefits for both companies and customers. We also note that after divestiture, securitization may then be possible.

2. Methods of Stranded Cost Recovery

(a) Accelerated Amortization and Regulated Rate Cuts

(i) Positions of the Parties

Duquesne's major proposal was to have its offer of an immediate divestiture of its generation assets accepted. (Duquesne M.B., p. 18). It contended that if this offer were accepted, most disputes regarding the quantification of stranded costs and the methodology for recovering them would be resolved.

In the event the offer to divestiture were not accepted, Duquesne proposed to set CTCs pursuant to Section 2804(4)(v) of the Act. This Section provides:

> 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 rate which have been approved by the [C]ommission as of the effective date of this chapter, the utility shall not be required to reduce its capped rates below

> the capped level upon the complaint of any party if the [C]ommission determines that any excess earnings achieved under the cap are being utilized to mitigate transition or stranded costs for the benefit of ratepayers or to offset other known and measurable cost increases that would be recoverable under traditional ratemaking but are not included within the capped rates.

The OCA objected to this method because it does not produce immediate rate reductions. (OCA St. 1 at 13).

The OCA and others argued that this is a misreading of the Act. The OCA proposed the establishment of a specific CTC, specific T&D rates, and a specific market price of generation (avoidable generation component). The OCA states that ratepayers who remain with Duquesne should only be required to pay the sum of these components. The OCA submitted that if the sum of these components produces a rate below the current rate, customers should realize a rate reduction. (R.D., p. 443). The OCA noted there is one difference between the Commission's approach in its Order in the PECO case and that recommended by the OCA in this proceeding. The OCA submitted that the approach taken in the PECO case should, thus, be modified in this case. (R.D., pp. 443-444).

Duquesne contended that the OCA's argument cannot be accepted because Section 2804(4)(v) is written in proscriptive terms. Consequently, Duquesne submitted that the only real issue is whether Duquesne's proposal for implementing Section 2804(4)(v) requires modification. On that issue, the only real dispute relates to the "ROE spillover" proposal.[20]

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[20] Duquesne states that notably, no party took serious issue with Duquesne's commitment to amortize a minimum of $1.7 billion over the transition period, Duquesne

The OTS did not oppose the Company's ROE spillover proposal, with one exception, that being the 10.50% ROE should be substituted for Duquesne's 11.5% ROE in the Company's ROE spill over proposal. (R.D., p. 438).

The OCA further argued that the Company's approach of maintaining its rates at current levels subject to a future final valuation and subject to the ROE spillover is inconsistent with the law and unwise in that it will: (i) unnecessarily postpone the determination of the CTC resulting in uncertainty to ratepayers; (ii) likely require the establishment of a false proxy for the market price; (iii) deny ratepayers the benefits of any near-term rate savings; (iv) remove incentives to mitigate stranded costs; and (v) would require substantial regulatory oversight that is inconsistent with the objectives of the Act. (R.D., p. 438).

The City argued Duquesne's ROE spillover mechanism fails to provide Duquesne with an incentive to reduce costs or mitigate stranded costs. The City continues that the spillover fund can be manipulated so that earnings can be used to fund items associated with unregulated market transactions. For instance, according to the City, Duquesne could increase its capital expenditures before the end of the transition period so that reduced expenditures would be needed after the transition period is over when Duquesne is forced to compete. The City also states that Duquesne could also use earnings to build market share by selling power below market prices. (R.D., p. 440).

HSS/ARI noted 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

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St. 2 at 39-40, Duquesne Exh. DJC-6; this proposal provides ratepayers a guarantee that Duquesne will achieve the aggressive cost reduction and containment projections contained in its case-in-chief. (Duquesne St. 1 at 5).

amortization of its generation assets by $1.7 billion through 2005, ostensibly for the purpose of mitigating stranded costs. However, HSS/ARI claimed that Duquesne has no stranded costs to mitigate. As a consequence, Duquesne has no right to accelerate amortization and depreciation (R.D., p. 441).

(ii) ALJ's Recommendation

The ALJ concluded that the OCA positions, which entailed immediate rate reductions but also an extension of the transition period, should be rejected. (R.D., p. 447).

The ALJ observed that the Company's proposal appears to track the exact language of the statute. The ALJ recommended that, to ensure "excess earnings" will be used to accelerate the amortization of stranded costs, Duquesne should be directed to file annual earnings reports in sufficient detail to permit the Commission to monitor the amortization process. For these reasons, the ALJ recommended acceptance of the Company's proposal for accelerated amortization under Section 2804(4)(v) with the ROE spill-over mechanism set at the level of 11.5% (R.D., pp. 436-437).

The ALJ also noted that if a merger is achieved, the methodology the OCA proposed for determining the Company's stranded costs should be used, since that approach appears the most reasonable, and substantial evidence supports it. Moreover, the ALJ found that the OCA's approach will allow the Commission to establish Duquesne's stranded costs in this proceeding at this time so the clock can begin ticking to bring the transition period quickly to an end without further delay. For these reasons the ALJ rejected any proposal to extend the transition period is rejected. (R.D., pp. 447-448).

(iii) Parties' Exceptions

The OCA claims that the ALJ erred in suggesting that Duquesne's ROE spillover mechanism is an appropriate mechanism to address the Company's excess earnings (OCA Exc., p. 7, 9). The Environmentalists added that the ALJ erred in accepting the Company's proposal for accelerated amortization of the CTC (Environmentalists Exc., p.4). HSS/ARI likewise indicated that the ALJ erred in approving Duquesne's proposal to accelerate amortization and deny an immediate rate reduction (DII Exc., p. 24-25).

PRA supports Duquesne's ROE spill-over mechanism (PRA Exc., p. 14). PRA argues against the ALJ recommendation that Duquesne not be required to "share" in the appropriate recovery of stranded costs as proposed by OCA and DII (PRA Exc., p.16). PRA also objects to the ALJ's rejection of the PECO Energy methodology (R.D., p.554) (PRA Exc., p. 18). PRA further contends that the ALJ's methodology incorrectly calculated the CTC and shopping credit (PRA Exc., p.18).

The OCA argues that the ALJ's recommendations with respect to the development of the CTC, shopping credit, and rate reductions should be adopted (R.D., pp. 555-557). Further the OCA requests that we clarify that, in the absence of divestiture, there should be a one-time determination of stranded costs rather than postponing that determination until the year 2003 (OCA Exc., pp. 3-4, 9).

The OCA argues that the ALJ's recommendation to reject an immediate rate decrease is inconsistent with the adoption of the proposed levelized rate reduction at p. 556 of the ALJ's Recommended Decision. The OCA urges the Commission to clarify, or modify, the statements on p. 447 of the Recommended Decision to make them

consistent with the result on page 556 of the Recommended Decision. (OCA Exc., pp. 1-8). The Environmentalists argue that the ALJ erred in rejecting a guaranteed rate reduction for the Company's customers. The Environmentalists contend that the Company should not be allowed to defer this benefit (Environmentalists Exc., p. 5).

(iv) Resolution

Duquesne argues that present rates should remain in effect without consumer savings during the transition period, permitting quicker recovery of stranded costs. On the other hand, the OCA argues that a direct regulated rate cut should be approved for all customers whether or not they shop. Neither proposal is consistent with the Act or the record of this proceeding, and both are rejected.

The CTC must be calculated as the amount necessary to fully amortize the authorized recoverable stranded and transition costs over the recovery period, including a return on the unamortized principal balance. All customers will pay the unbundled transmission and distribution rate. Non-shopping customers will pay the unbundled rate for generation such that the total rate will precisely reflect current existing rates. A proportionate amount of the unbundled generation rate collected from non-shopping customers will be allocated to CTC recovery.

Customers choosing to shop will pay their chosen supplier instead of Duquesne for generation. These customers will continue to pay a temporary charge for Duquesne's stranded generation related costs to Duquesne through the CTC. The residual amount left over from the unbundled generation rate and the CTC amount is the Shopping Credit.

We find that Section 2808(4)(v) of the Act has no relevance to a determination of the proper CTC. It 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 upon the complaint of any party if 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 to offset other known and measurable cost increases that would be recoverable under traditional ratemaking but are not included within the capped rates.

This section provides a utility with a defense against a complaint seeking a reduction in capped rates because of overearnings, something that is not being done in this case. Even if we were to accept Duquesne's argument that it is not presently earning its authorized rate of return, the section would be inapplicable on its face because the section only applies when the utility is, in fact, overearning. If it were read to do that, no customer would have any possible economic benefit from shopping. If it were read to require a shopping customer to pay its full existing rate to its present supplier, competition would be impossible and nearly the rest of the Act could not be implemented.

This section is a modification of the rate cap requirements of Section 2804(4) of the Act. Section 2804(4) does not raise any issues related to the calculation of the CTC. Section 2804(4) does not require that Duquesne be entitled to collect its full capped rate from a shopping customer.

We conclude that the CTC must be calculated as the amount necessary to fully amortize the authorized recoverable stranded and transition costs over the recovery period, including a return on the unamortized principal balance as described above. All customers will pay the unbundled rate for generation such that the total rate will precisely reflect the existing rates. Finally, we cannot agree with the OCA's proposal that the existing rate should be cut in the absence of a cost-of-service analysis.

Customers choosing to shop will pay their chosen supplier instead of Duquesne for generation; however, these customers will pay the CTC to Duquesne. The residential amount compared to the unbundled generation rate is the CGC. As we enter the era of competitive deregulated generation, this Commission is not establishing an administratively determined market price for generation that directly imposes the parameters for savings from selecting a competitive supplier. The CTC shall be designed to reflect a declining CTC over the transition period ending December 31, 2005. We conclude that it is appropriate to use a declining CTC in order to properly balance Duquesne's earnings in the early years of the transition and reasonable customer savings during the entire transition period.

We also reject the OCA's Immediate Rate Reduction Proposal consistent with the ALJ's recommendation. Rate reductions are a function of shopping. The Act provides an opportunity to achieve lower rates for Duquesne's customers through the transition to a full competitive market.

We conclude that the CTC must be calculated as the amount necessary to fully amortize the authorized recoverable stranded and transition costs over the recovery period, including a return on the unamortized principal balance. All customers will pay the unbundled transmission and distribution rate. Non-shopping customers will pay the

unbundled rate for generation such that the total rate will precisely reflect currently the existing rates. We cannot agree with OCA's proposal that the existing rate should be cut in the absence of a cost of service analysis.

(b) Rate Cap/CTC Extension

(i) Positions of Parties

The Company takes no position on this issue. (R.D., p. 448).

The OTS proposed that the rate cap under Section 2804(4) of the Act and CTC collection period be extended if the final valuation in 2003 determines a stranded cost level which would produce "rate shock." Apparently it is the Company's intention to begin collecting stranded costs determined by the panel, pursuant to the 2003 valuation, on January 1, 2004, and to collect these costs over the two remaining transition years (R.D., p. 448).

DII posited that Duquesne acknowledged that under its delayed valuation method for determining stranded costs, the Company may need an extension of the CTC recovery period in order to fully recover stranded cost revenues that the Commission authorizes. (Duquesne St. 2 at 41). Duquesne proposed to make this determination based on a CTC revenue analysis after the final delayed market valuation. (Id). Duquesne sought to extend or shorten the CTC collection period accordingly. (Id). Although DII generally assented to the concept that the collection period be extended, its agreement is subject to certain conditions. (DII M.B. at 72).

As a preliminary matter, DII noted that the Company's perceived need for an extension of the recovery period is created, in large part, by the Company's proposals to delay the market valuation of its assets and to have a variable CTC. DII's analysis, on the other hand, established a definitive level of stranded costs to be recovered and a fixed schedule of CTCs. DII submitted, with a high degree of certainty, that if the DII recommendations are adopted (and Duquesne's sales remain comparable), Duquesne will fully recover its allowed stranded cost by 2002. (DII St. 1 at 35, Exh. SJB-5). (R.D., p. 449).

The PRA posited the mere possibility of an undercollection of stranded costs is not a sufficient basis to now order an extension of the CTC. The PRA further noted that the statute provides for an annual reconciliation designed to insulate Duquesne from sales variations. Thus, the Act solely contemplates a catastrophic loss of load such that the CTC must be increased enormously to permit Duquesne 100% recovery of its Commission determined level of stranded costs. (R.D., p. 451).

The Environmentalists argued that the Act provides for the CTC collection period to end on December 31, 2005.

(ii) ALJ's Recommendation

The ALJ noted that Duquesne proposed CTC collection will end on December 31, 2005, and Duquesne is not requesting that the statutory period be extended. Because Duquesne is not proposing any rate relief for its customers during the CTC collection period, it is especially important that the CTC collection not be extended. (R.D., p.451).

(iii) Parties' Exceptions

Duquesne takes no position on this issue. The OTS argues that the ALJ erred in concluding that it is unnecessary to grant the OTS Rate Cap/CTC Extension proposal. The OTS contends that its proposal is essential to avoid possible CTC "rate shock" if a deferred final evaluation is implemented (OTS Exc., pp. 16-17).

(iv) Resolution

Since we have rejected Duquesne's basic proposal and adopt a CTC collection period that coincides with the rate cap, the rate cap extension issue is not applicable at this time. We note that our establis hment of the CTC recovery period may be modified upon receipt of the divestiture results.

According to the ALJ, the foregoing recommendations render this proposal for rate cap/CTC extension unnecessary. Therefore, the Commission need take no action on this subject. We find the ALJ's recommendation relative to rate cap/CTC to be reasonable and in accord with the evidence if there is no divestiture; otherwise the recovery period may be extended. Therefore, we shall adopt the ALJ's recommendation.

3. Other Arguments Regarding Recovery of Stranded Costs

(a) Positions of the Parties

The Company noted the only other position that requires attention here is that of Mr. Hughes. Mr. Hughes, a Duquesne ratepayer, believes the Commission should

make a determination as to whether Duquesne's current rates are just and reasonable before it makes decisions with regard to prospective issues such as stranded cost recovery. Mr. Hughes contends Duquesne's current rates are unjust and unreasonable as a result of the failure of the Perry 1 and Beaver Valley 2 generating units to provide an economic benefit to ratepayers. He continues that the high cost of these units has precluded Duquesne from giving its customers rate reductions. Mr. Hughes contends that Perry 1 and Beaver Valley 2 failed to meet the useful side of the used and useful test. He notes that Duquesne's rates were set by the Commission in March 1988. Mr. Hughes continues that, in that rate base case, the Commission found that Duquesne had failed to meet its burden of proof that Perry 1 and Beaver Valley 2 did not represent economic excess capacity on the Company's system; and the Commission made a relatively small excess capacity adjustment for this at the time.

Duquesne argued that the result sought by Mr. Hughes, however, suffers from the same flaws as the "sharing" proposals, in that it bears no relation to Duquesne's mitigation efforts or opportunities and does not meet the standards set forth in Duquesne. Duquesne submitted that Mr. Hughes' factual claims are either in error or are attempts to rehash matters previously raised, and decided, in Duquesne's last rate case. (R.D., p. 452).

The City argued that Duquesne's methodology impairs the formation of a competitive market, the very goal of the Act. According to the City, under Duquesne's plan, it will be very difficult for new suppliers to meaningfully compete for market share. (R.D., p. 453).

The City contended that, in a properly functioning competitive market, decisions on whether to supply power are based on avoidable costs. Under Duquesne's

plan, supply decisions have nothing to do with avoidable costs and everything to do with overrecovery of stranded costs. For instance, according to the City, using Duquesne's own forecasts, Duquesne should shutdown its Elrama plant since Elrama's avoidable costs will exceed revenues from sales by $215 million. The City continues that, instead, Duquesne's plan is to operate this plant to the detriment of ratepayers. (Id. at 20).

Mr. Hughes supported the OTS and HSS/ARI in requesting that the Commission not include the Brunot and Phillips cold reserved units in its stranded cost calculation. (R.D., pp. 460-461).

(b) ALJ's Recommendation

The ALJ observed that in various sections of his Recommended Decision, he addressed the concerns of the City and certain issues Mr. Hughes raised. The ALJ was not persuaded by the arguments presented to change his recommendations as previously delineated in this Section. As a result, the ALJ recommended that the relief sought by Mr. Hughes should be denied.

(c) Parties' Exceptions

Mr. Hughes argues that the ALJ erred in rejecting the following four arguments: 1) Duquesne's current rates are unjust and unreasonable; 2) Duquesne's nuclear units should not be included in the Commission's calculation of stranded costs; 3) Duquesne's Cold reserve units should not be included in the Commission's calculation of Duquesne's stranded costs; and 4) Duquesne has a poor stranded cost mitigation track record (Hughes Exc., pp. 1-9)

(d) Resolution

We reject Mr. Hughes claims because, as is apparent from a review of the record of this proceeding, such claims are either in error or are attempts to rehash matters previously raised, and decided, in Duquesne's last rate case.

G. Discount Rate For Stranded Costs

Regarding the proper discount rate for stranded costs, we note that Duquesne incorporates an equity rate of 11.5 percent. (R.D., pp. 558-560). The OTS recommended 10.5 percent (R.D., pp. 563-577) and the OCA 10.0 percent. (R.D., pp. 558, fn. 185).

The ALJ recommended a discount rate of 10.5 percent as proposed by the OTS. (R.D., pp. 586-587). In its Exceptions, Duquesne argues that the ALJ erred in not determining that Duquesne had established that its proposed discount rate of 11.5 percent is justified. (Duquesne Exc., p. 31).

In its Exceptions, PECO notes that it makes no specific recommendation regarding Duquesne's cost of capital, its appropriate after-tax discount rate or the return it should be allowed to earn on the unamortized balance of its stranded costs. However, PECO argues that PECO was granted a pre-tax return equivalent to its embedded cost of long-term debt (7.47 percent) on the grounds that the recovery of CTC revenues is essentially risk free. While rejecting this reasoning, PECO contends that this same rationale should apply to all other incumbent utilities. PECO submits that there can be no justification for granting Duquesne a 10.5 percent return on its stranded costs while

providing PECO with an approximate 4.73 percent equity return (7.4 percent less applicable federal and state income taxes).

In considering this matter, we note that the ALJ recommended granting Duquesne a 10.5 discount rate , based upon the recommendations of the OTS. However, we observe that, based on its DCF analysis, the OTS stated that the range of 9.5 percent to 10.5 percent represents a reasonable cost range of common equity for publicly traded electric companies. (OTS St. 1, pp. 31-32, R.D., p. 570). The record in this proceeding demonstrates that Duquesne will experience a reduced risk profile because of the CTC recovery mechanism. Based upon the OTS' DCF range, we adopt the recommendation of the OCA to use a 10 percent return for the equity portion of the discount rate for Duquesne as reasonable and compensatory. This results in an after tax discount rate of 7.29 percent for the net present value calculations of Duquesne's stranded costs.

V. THE COMPETITIVE TRANSITION CHARGE

A. Conceptual Disputes Regarding Calculation of CTC/CGC

1. Positions of the Parties

The Company noted the method for calculating the CTC is one of the most complex and misunderstood aspects of this case. While there are a multiplicity of proposals in this regard, they generally fall into two categories. The first, proposed by Duquesne, is a "top down" approach that sets rates according to Section 2804(4)(v) of the Act. The second general approach, proposed by the OCA (and applied in modified form in PECO Energy), is a "bottoms up" methodology.

Duquesne argued the competitive generation credit, ("CGC") also referred to as the "avoidable generation charge" or "shopping credit," is not a charge, but is simply the amount of the utility's charges that a customer will not have to pay if the customer purchases generation from an alternative supplier. Duquesne continues that the CGC is a regulatory concept and is nowhere defined in the Act, and in this case, and for different purposes, parties have defined, and calculated, the CGC in different fashions. According, to Duquesne, the CTC could be designed in several different ways. Duquesne opined that the residual establishment of a shopping credit does not purport to track a market price for generation but is the Commissions' determination of what is necessary to create incentives for customers to want to shop and for sellers to be able to offer savings, therefore building the foundation for a competitive market. According to Duquesne, nothing in the Act explicitly or implicitly links the unbundling of rates and the design of

the shopping credit to market price. Duquesne posits that under the Act, the CTC is the charge necessary to recover authorized transition and stranded costs over the recovery period. For example, it could be designed to provide levelized collection of stranded costs, declining CTC, levelized rate reduction, or a levelized charge. Some parties proposed to define the CGC as an administrative determination of the market price of generation, although parties using this approach proposed substantially differing methods and results. The OCA proposed a levelized rate reduction which utilizes a declining CTC.

The OCA contended that while the pre-determined shopping credit, under its proposal, may not precisely track market prices, it will provide a reasonable initial proxy of such prices and sufficient certainty to enable an infant marketplace to grow. The OCA continued that after the phase-in period, the Company will be permitted to charge "prevailing market prices" for generation and such prevailing market prices will, in effect, be the CGC. The OCA also noted that Enron proposed to treat the CGC as the residual rather than providing for rate reductions, relying on the Commission's Order in PECO Energy. The OCA posits that Enron's approach would require the Company to charge more than this amount and would effectively cause remaining utility customers to subsidize shopping customers. (R.D., pp. 468-472).

DII suggested the Commission's determination of a CTC design methodology for the recovery of Duquesne's stranded costs encompasses many sub-issues. The fundamental issue, according to DII, is the "overall approach" of the CTC design. DII defined "overall approach" to mean whether the methodology uses a CTC residual approach or a CGC residual approach. DII contended that the choice of methodology is an overarching issue, because use of one methodology or the other may

dictate whether customers are economically able to participate in the competitive market during the transition period. DII submitted that adoption of the CTC residual methodology by the Commission is clearly appropriate under the Act.

HSS/ARI submitted 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. If the Commission grants any portion of Duquesne's stranded cost claim, HSS/ARI submitted that Duquesne's proposal for calculating CGCs and CTCs be rejected. (R.D., p. 476).

The Environmentalists posited the unbundling of rates is where the rubber meets the road for the ratepayers, for this tells customers how much of their bill they can take shopping for alternative suppliers. The Environmentalists proposed to treat the CGC as a residual. According to the Environmentalists, the generation or shopping credit is the most critical number in the unbundled rates to both the ratepayers and for the alternate suppliers. The Environmentalists argued that without a healthy shopping credit, shopping will not produce meaningful savings for customers, customers will not shop, EGSs will not find customers and will not survive. (R.D., p. 478).

Enron explained that Duquesne's methodology for unbundling of rates subtracts its proposed T&D rate from the present total and then sets the CGC at a wholesale market price, calculated through an annual RFP conducted by Duquesne. The residual is then declared the CTC. Enron argued that Duquesne's approach, while in the 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. Enron submitted that, 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 Act, and the PECO Energy approach on their heads. Therefore, Enron concluded that the record does not support the OCA/DII position.

PECO contended that the generation credit will apply to all customers and be the generation charge for all customers who: cannot choose, do not choose or who choose and then return to Duquesne unless and until (a) Duquesne voluntarily changes those rates pursuant to Chapter 13 of the Code; or (b) the rate for such "Provider of Last Resort" customers is changed pursuant to a formula established by the Commission pursuant to regulations. (R.D., pp. 479-492).

MAPSA argued that Duquesne's proposed CGC is too low to allow for the development of meaningful competition for retail sales of electric energy and should be rejected. MAPSA advocated a stranded cost approach, which focuses on administratively setting the CGC. Under MAPSA's approach, the CTC would be a residual. As MAPSA pointed out, in PECO, the Commission did not follow MAPSA's approach as advocated in this case. MAPSA vigorously disputed Duquesne's methodology and stated that it could endorse the PECO methodology, should the Commission feel bound to follow the PECO approach. (R.D., pp. 492-501).

(a) Resolution

In PECO, we stated previously that:

> The shopping credit is not a selected number. It is a number that results from the difference between a particular

customers' total rate as of January 1, 1997 and the sum of T&D and CTC rates established pursuant to this order.

(PECO, p. 42).

Based upon the preceding discussion, we find that the CGC is a residual number which is not calculated but produced after determinations of the portions of Duquesne's rates which were associated with transmission and distribution and CTC. When these elements are determined and removed from Duquesne's current rates, the remainder-whatever that may be is the customer generation credit.

(b) Summary

We adopt the merger savings of $152.28 million, as an offset to stranded costs.

We support an immediate rate reduction of $15 million. We accelerate the customer rate reductions to begin January 1, 2000, rather that in 2001, as Duquesne proposed

We adopt the DII's calculation of nuclear decommissioning costs as of December 31, 1998, on a net present value basis.

We conclude that Duquesne has not documented any known and measurable future fossil decommissioning expense that meets normal ratemaking standards, demonstrated that the costs would be recoverable under traditional regulation, demonstrated that the cost will in fact be stranded, or demonstrated that the costs will be

non-mitigated. Duquesne's claim, therefore, does not meet the basic requirements for stranded cost recovery and is rejected.

We conclude that Duquesne's SFAS 109 obligation should be treated as a tax liability form the balance of plant in service and not as a regulatory asset. We, therefore, reduce the Company's regulatory asset claim by $62.94 million.

We conclude that Duquesne's unamortized debt costs as of December 31,1998, should be treated as a regulatory asset in the amount of $45.77 million.

We adopt Duquesne's claim for unamortized sale and lease back premiums as modified by the OCA.

We permit recovery of $23.5 million, on a net present value basis of deferred rate synchronization costs associated with Perry and Beaver Valley 2.

We adopt Duquesne's claim for compensated absences, injuries and damages of $14.24 million, as computed by the OCA, on a net present value basis.

We disallow Duquesne's claim for deferred coal costs of $13.5 million, finding that Duquesne has failed to show that these costs would be recoverable in a regulated environment.

We disallow Duquesne's $3.92 million net present value claim for recovery of deferred care taker cost as a regulatory asset as the record does not appear to support a

determination that the assets associated with these caretaker costs will be returned to service within the foreseeable future.

We disallow Duquesne's claim for pre-accural of nuclear outages of $10.29 million on a net present value basis. We find that this adjustment is included in plant operations and allowance as a regulatory asset would double count these expenses.

We allow Duquesne's claim for transition costs of $10.59 million, representing expenses of this proceeding and pilot program deferrals, as they were required to be expended to implement the Act.

We accept Duquesne's claim for $1.92 million, on a net present value basis, of SFAS 106 deferred costs. These costs are required under GAAP, are known and measureable, and incurred under traditional regulation, and otherwise meet the definition of stranded costs.

We agree with the exceptions of Duquesne and reject the ALJ adoption of the HSS position regarding the Warwick Mine. The inclusion of the remaining plant balance in net plant in service is the proper treatment to be accorded this stranded property. We have disallowed the regulatory asset claim for deferred fuel costs associated with the past operation of the mine. The net plant is the to go cost that would have had rate recovery through the ECR absent the Act. Duquesne never sought treatment of the property as a regulatory asset as claimed by HSS.

We adopt the ALJ's determination that Duquesne's past action regarding stranded cost mitigates have been adequate, but the Company must also continue a

commitment to mitigation. We are aware that Duquesne's mitigation efforts will have achieved $1 billion in savings and $700 million in avoided rate increases by 2005. Duquesne St. 1 at 20; Duquesne St. at 24-26. Additionally, Duquesne auctioned a generating prior to the Act and used the proceeds to increase the depreciation of nuclear assets. Duquesne St. 2 at 10-12; Duquesne St. 1-R at 21.

We reject the ALJ's conclusion that the Act prohibits sharing of stranded costs and that any sharing amounts to a taking. To the contrary, we find that the Act contemplates the Commission's 's deliberation as to just and reasonable rates for recovery of stranded costs. It is quite apparent that the Act does not restrict the Commission's deliberation. The fact that sharing is not explicitly detailed, was to provide the Commission's the full opportunity to customize the stranded cost result and recovery to the circumstances of the individual utility. To require Duquesne to share the stranded generating assets would amount to denying it recovery of a portion of its proven, stranded costs which cannot be mitigated.

We conditionally adopt the ALJ's recommendation on the issue of securitization. We find that the Act provides that securitization may be proposed by the Company. While Duquesne, as a stand alone company, does not believe that it can securitize within its sale/leaseback and financial covenants, the post merger company should examine the option for both operating territories and determine, after a fresh look, whether securitization can provide benefits for both companies and customers. We also note that after divestiture, securitization may then be possible.

On consideration of the positions of the parties, we adopted the levelized CTC method for CTC calculation. Duquesne proposed a flexible valuation and recovery

mechanism which would reset the CTC every year. Because we are determining stranded costs and the need for their recovery, we removed the need for flexible amortization as proposed by the Company.

We conclude that the CTC must be calculated as the amount necessary to fully amortize the authorized stranded and transition costs over the recovery period, including a return on the amortized principal balance. All customers will pay the unbundled transmission and distribution rate. Non-shopping customers will pay the unbundled rate for generation such that the total rate will precisely reflect currently the existing rates. We cannot agree with OCA's proposal that the existing rate should be cut in the absence of a cost of service analysis. The CTC is designed to promote competition, not to serve as a single rate reduction.

We concur with the ALJ's recommendation which indicates that rate cap/CTC extension is unnecessary in order to recover the allowable stranded costs under the rate cap, unless there is an auction, we tentatively adopt seven years.

We adopt the recommendation of the OCA to use a 10% return for the equity portion of the discount rate for Duquesne as reasonable and compensatory. This results in an after tax discount rate of 7.29% for the net present value calculations of Duquesne's stranded costs.

We agree with PRA that the Act requires us to establish the CTC. It is this foundation that guides our resolution to reject both the Company proposal and the OCA proposal, which both result in the CTC being a residual of a calculation, rather than a finding of the Commission.

Pursuant to Section 2808(a) of the Act we concluded that the transition cost responsibility be assigned to each customer class on the basis of the production capacity allocator utilized in Duquesne's last rate case.

We agree with the ALJ that the Company's optional CTC design should not be implemented.

We agree with OCA and find that rate class specific annual reconciliation is appropriate to avoid inter-class shifting of stranded cost recovery.

We do not accept the recommendation of the ALJ to adopt the OCA fixed schedule of market prices and residual CTC calculation. We find that the CTC should be determined on a levelized basis, based upon our stranded cost finding being amortized with an appropriate return on the Unamortized balance. The CTC should remain in place until 12/31/05. It should be reconciled annually by rate class for actual sales versus the forecasted sales.

The CTC shall be calculated on a, "per kwh" basis, allocated to each class. Section 2808(a) requires that the CTC be calculated in a manner that does not shift interclass or intraclass costs and is consistent with the allocation methodology for utility production plant accepted by the commission in the most recent base rate proceeding. We conclude that Duquesne properly used the cost of service study in its most recent base rate proceeding for this purpose as required. The revenue requirement of the CTC shall be allocated on a class basis to assure no interclass cost shifting, and cost responsibility to each customer class on the basis of the production capacity allocator utilized in Duquesne's last rate case.

The CTC distorts market prices and directly impacts the competitive market because it limits the opportunities for consumers and competitive suppliers to achieve savings and earn profits, respectively. The parties have presented various proposals for adjusting CTC recovery levels in each year to address their concerns. We conclude that the facts of this case and the stranded recovery authorized herein support the use of a levelized CTC over the transition period.

The CTC shall be calculated based on annual 1999 sales of 13,177,788 MWH, escalating annually per the Attachment to this Opinion and Order.

2. Design of CTC Issues

(a) One Time Determinations v. Fixed Schedule

The Company observed that Duquesne and the OCA's methods differ in that Duquesne's shopping credit will adjust each year (per the RFP results for that year), while the OCA sets a fixed shopping credit in advance for each year of the transition period. (R.D., p. 503).

The OCA related that part of the Company's final valuation proposal is to adjust the CGC annually to reflect market prices. The OCA believed that annual adjustment of the CGC presents a number of problems. Perhaps most important is that there may be significant controversy over the price which is produced by Duquesne's auction, requiring Commission monitoring and possibly review of this process.

Additionally, use of an annual auction would make it difficult to establish rates during the CTC recovery period today. The OCA recommended that the Commission reject this approach in favor of setting the CGC in this proceeding.

DII suggested another conceptual difference among the CTC proposals in this proceeding is whether the schedule of CTC and CGC charges for each year of the transition period should be established definitively as part of this proceeding or whether the CGC and CTC should be redetermined each year. DII recommended that Duquesne's proposal be rejected and that the Commission establish a fixed schedule of CTCs for each year of the transition period as part of this proceeding using the methodology they recommend. (R.D., pp. 507-508).

PRA noted that Duquesne desires to calculate actual market rates on an annual basis. PRA argued that there are inherent problems and that this annual true up method may be illegal in enacting the Competition Legislation. PRA continues that the Act requires the establishment of the CTC (and by definition the CGC) in this proceeding. According to the PRA, there is no provision for an annual true-up of the market price. PRA opined that the Legislature recognized the risk of this method by allowing for full recovery of a just and reasonable level of stranded investment with the ability to correct for variations and customer usage. This ability to correct provides a significant comfort level to utilities which see a decline in sales. (R.D., p. 508).

(i) Resolution

Without engaging in a lengthy analysis of the conceptual disputes regarding calculation of the CTC/CGC in the record, we adopt the levelized CTC, adjusted annually

for actual sales, as the primary method for calculating the CTC. Consistent with the ALJ's recommendation, we reject the optional rate design for customers to choose for their CTC payments.

(b) Determination of Class Responsibility for Stranded Costs

The OCA and the OSBA recommended allocation of stranded cost responsibility to each class on the basis of the production capacity allocator utilized in the Company's last rate case (R.D., p. 509). The OSBA added that maximum CTC revenues should be collected, as available, from all rate classes to effectively amortize Duquesne's stranded cost balance as quickly as possible (R.D., p. 511). DII argued that this methodology is inappropriate because it results in cost-shifting and possible rate cap violations. DII claimed that stranded costs must be unbundled as they are contained in current rates (R.D., p. 515). HSS/ARI noted that Duquesne's rate proposal should be modified by reducing revenue for certain classes (R.D., p. 522). PRA suggested that stranded costs should be allocated in the manner required by the Commission in the PECO proceeding (R.D., p. 522).

(i) Resolution

Section 2808(a) of the Act specifies that transition cost responsibility to each customer class in the following manner:

> ...[E]very customer accessing the transmission or distribution network shall pay a competitive transition charge to the electric distribution company in whose certificated territory that customer is located. The costs to be recovered shall be allocated to customer classes in a manner that does not shift

interclass or intraclass costs and maintains consistency with the allocation methodology for utility production plant accepted by the commission in the utility's most recent base rate proceeding.

Pursuant to Section 2808(a) of the Act we direct that the transition cost responsibility be assigned to each customer class on the basis of the production capacity allocator utilized in Duquesne's last rate case.

(c) Levelized CTC v. Other Methods

Duquesne proposes to put some CTC in fixed and declining variable. The OCA recommended the establishment of a levelized rate reduction to allow full recovery of stranded costs and a declining CTC because of the estimated increase in market prices (R.D., pp. 522-523). PRA agreed with OCA and indicated that a levelized recovery period is consistent with the Act (R.D., p. 524).

The OSBA related through the Company's rate redesign plan, Duquesne proposes to reduce current rate levels over 25% on average for consumption above 1996 levels. Duquesne St. 5 at 31. This proposed rate reduction on incremental usage has a dual purpose: (i) to provide more efficient price signals, and (ii) to encourage economic load growth. The OSBA advocated an amendment to the Company's original plan whereby a customer could select an all-variable CTC or a fixed/variable CTC dependent upon which plan would best suits the customer's needs and anticipated consumption.

The Company adopted the amendment proposed by OSBA, noting that this change causes its rate redesign plan to be more reasonable with respect to the customer's interests. The OSBA agrees. (R.D., pp. 529-531).

DII argued that use of a levelized CTC for recovery of Duquesne's stranded costs may be inappropriate because it may prevent some customers for participating in the competitive market (R.D., p. 523). Environmentalists contended that the Act implied a straight amortization of stranded costs (R.D., p. 525). DII noted that Duquesne proposes a mandatory rate redesign that collects 50% of the customer's monthly CTC charge on a fixed dollar per month basis and 50% on a consumption basis. DII submitted that the Commission must reject this proposal because, it violates the rate cap and anti-cost shifting provisions of the Act.

PRA argued that Duquesne proposes to radically modify its existing rate structure. It proposes to unbundle its charges so that a portion of the CTC is collected through a fixed charge component while the residual is collected in the energy rate. There are several problems with this methodology.

The Environmentalists opposed the rate redesign proposal, which Duquesne has attempted to insert into its restructuring plan. Duquesne proposes to shift costs from volume-based charges to fixed customer charges. The Environmentalists oppose this change for several reasons.

The Environmentalists recommend that the Commission reject this rate redesign as unsound and inappropriate and require the Company to structure the CTC on

a mils per kWh basis. The Company can ensure against the risk of under-collection by implementing a true-up at the end of each year. (R.D., pp. 535-536).

MAPSA contended that Duquesne has proposed to calculate and collect a customer-specific competitive transition charge. In essence, Duquesne's proposal is to use a previous years' usage to determine a customer's future year total CTC allocated share and then to charge a customer a fixed CTC based upon the previous years' usage. MAPSA M.B. at 27. According to MAPSA, Duquesne's proposal is contrary to law because it violates the Commission's mandate that CTCs be charged on a per-kWh basis. (R.D., pp. 536-537).

(i) Resolution

We reject Duquesne's proposal to collect half of the CTC through a fixed charge and half through a declining variable charge, because it shifts costs to low users,

We also conclude that a levelized CTC is appropriate.

We agree with the ALJ that the Company's optional CTC design should not be implemented. In particular, as this proposal was closely linked to the overall proposal of Duquesne, it was based upon a residual CTC design which we have rejected as not in conformance with the Act. While a customized CTC sounds attractive, we believe it will lead to annual reconciliation problems. Finally, we find that to have multiple CTC designs in place at this time will add confusion for the customers as they enter into customer choice.

(d) Reconciliation of CTCs

(i) Class Reconciliation of Annual Sales

OCA argued that consistent with the statutory requirement for annual reconciliation and with the OCA's proposal to allocate stranded costs by rate class, stranded costs should also be reconciled annually on a class-specific basis. (OCA St. 4 at 14-16). This approach is necessary to avoid inter-class stranded cost shifting and was specifically adopted in the PECO Order, Slip Op. at 113. (R.D., p. 539).

(ii) Position of the Parties

The Environmentalists explained that true reconciliation of the CTC requires reconciliation of the difference between the projected market price and the actual market price. The Environmentalists have already addressed the weaknesses of Duquesne's proposal to fix a market price by selling a block of power each year on the open market. (R.D., p. 541).

To avoid an over-recovery of stranded costs, the Environmentalists argue that the CTC should be reconciled to reflect changes in sales. Because the CTC are charges added to each kilowatt-hour, the total CTC recovery is directly dependent on the number of kilowatt-hours sold throughout the collection period. According to the Environmentalists, even a very small discrepancy between projected sales and actual sales will result in a large difference in collections. The Environmentalists posit that the Act directs the Commission to "establish procedures for the annual review of the competitive

transition charge" and to "reconcile the annual revenues received from the charge" at the approved level[21] and it should do so.(R.D., p. 541).

In designing the reconciliation mechanism, the Environmentalists asserted it is critical to prevent cost shifting between customer classes. The CTC should be assigned to each class and reconciliation should occur within each class.[22] This is important because of the different growth rates for the different classes. For example, if high growth is experienced in the residential class, and low growth in the industrial class and reconciliation was calculated on a system-wide basis, CTC recovery would be shifted to residential customers from the industrial customers.[23] With reconciliation by class, the residential CTC charge under this scenario would be reduced or shortened (to reflect the faster recovery) and the industrial CTC charge would be increased or lengthened (to make up for the under-recovery). (R.D., p. 542).

Duquesne proposed an annual readjustment of the shopping credit to reflect the results of an annual RFP for the sale of firm power, thereby annually readjusting the CTC and recoverable stranded costs as well.

In PECO Energy, Duquesne observed that the Commission accepted evidence that, with respect to the CTC proposed by PECO, a long-term debt rate represented the appropriate cost of capital. PECO Energy, Slip Op. at 107. While

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[21] 66 Pa. C.S. §2808(f).

[22] This position is shared by others. See, OCA St. 4 at 11-12.

[23] This hypothetical is exactly what has occurred this decade. The residential and commercial classes have experienced load growth, but the industrial class has seen a drop in number of customers, peak load and energy consumption.

Duquesne does not agree with that finding, it contended that is not pertinent here. Duquesne has not proposed a "fixed" CTC that is "trued up" each year for changes in sales levels, as was proposed in PECO Energy. Rather, Duquesne has proposed an ROE spillover and a commitment to amortize a minimum of $1.7 billion in stranded costs over the transition period. Duquesne urged approval of its CTC design proposal. If the immediate divestiture is accepted, Duquesne is willing to accept a CTC design that generally is consistent with the method used in PECO Energy, as discussed, supra. (R.D., pp. 549-550).

In order to ensure that the Company does not over-recover stranded costs, a CTC revenue tracking mechanism must be established. DII suggests that the Company should track CTC revenues on a monthly basis. The Company will begin the stranded cost recovery period with the unamortized total stranded cost balance authorized in this proceeding to be recovered from ratepayers. This balance will accrue interest monthly at the revenue requirement level (i.e., fully grossed-up cost of capital). Each month, the Company will accumulate the CTC revenues produced that month by each rate schedule. The unamortized stranded cost balance will be reduced each month by the accumulated monthly CTC revenues until the balance is fully amortized at a $0 level.

(iii) ALJ's Recommendation

On the subject of CTC, this Commission explained in the only restructuring application to date to receive final review, PECO Energy, Slip Op. at 103-104; PECO Energy, Slip Op. at 109-110.

The ALJ agreed with the OCA that its proposed market prices will serve as an appropriate proxy for actual market prices during the transition period with sufficient certainty to enable a nascent marketplace to grow. Under the OCA's approach, the CTC is a residual, which declines each year as the forecasted market prices for the CGC increase each year during the transition. The OCA's methodology for calculating the CTC will mean that the CGC will be sent annually according to the fixed schedule of market prices appearing in OCA Exhibits LS-7 & LS-7R. Of course, the Company's collection of the CTC will be subject to annual review by the Commission.

The ALJ recommended that the Commission adopt the OCA's recommendation to establish a levelized rate reduction. The ALJ further recommended that Duquesne's proposal be denied to redesign its rates pursuant to a two-part Customer Transition Charge, which would include a fixed (customer-specific) charge and a usage-based (class-specific) charge. The ALJ noted that consistent with the statutory requirement for annual reconciliation and with OCA's proposal to allocate stranded costs by rate class, stranded costs should also be reconciled annually on a class-specific basis. The ALJ concluded that this approach is necessary to avoid inter-class stranded cost shifting and was specifically adopted in PECO Energy, Slip Op. at 113.

(iv) Resolution

We agree with the OCA and find that rate class specific annual reconciliation is appropriate to avoid inter-class shifting of stranded cost recovery.

We do not accept the recommendation of the ALJ to adopt the OCA's fixed schedule of market prices and residual CTC calculation. We find that the CTC should be

determined on a levelized basis, based upon our stranded cost finding being amortized with an appropriate return on the unamortized balance. The CTC should remain in place until 12/31/05. It should be reconciled annually by rate class for actual sales versus the forecasted sales. Our Attachment A to this Order provides the expected CTC based upon the current forecast.

B. Return on Unamortized Balance

Regarding the return on the unamortized balance of the stranded costs as it relates to the CTC/CGC calculation, we conclude that Duquesne should be permitted to collect an annual return of 11.0 percent including the gross-up for taxes. We determine this to be appropriate because the risk of not collecting the CTC is low. Furthermore, we find that this return is comparable to the Company's long-term debt costs. (R.D., p. 577). It is within the range of the proposals of the parties. Furthermore, this return is on the unamortized principal balance. It, therefore, represents a "floor" for Duquesne's earnings. Duquesne has no limit on the return it may achieve in the competitive market.

VI. TARIFF ISSUES

A. Rule 4 Contracts

1. Positions of the Parties

In its argument before the ALJ, Duquesne stated that Rule 4 Contracts are executed "as a mitigation strategy to attract or retain incremental load that Duquesne would have otherwise lost to a competitive alternative." Duquesne St. 6-R at 4; See, also, Tr. 1029-30. Two issues have arisen regarding these contracts. First, DII contended that Rule 4 contracts should be unbundled so that customers can gain access to the competitive market. The second contention was OCA's argument that the revenue effect of Rule 4 "discounts" class should be imputed, for CTC calculation purposes, to the class receiving the discounts. (OCA St. 4 at 8-10). (R.D., pp. 588-589).

DII claimed that Duquesne inappropriately denies customers currently taking service under Rule 4 contracts the right of choice of electricity supplier guaranteed to them by the Act because Duquesne refuses to unbundle these contracts. (Duquesne St. 6-R, p. 4). According to DII, this refusal is anti-competitive, contrary to the Act and must be rejected by the Commission. Rule 4 customers must be granted their statutory right to direct access unless the particular contract clearly prohibits the customer from accessing competitive supply in the deregulated environment for the duration of the transition period. (DII St. 1, p. 54; DII M.B., p. 89).

HSS/ARI supported Duquesne's continued ability to offer Rule 4 contracts. HSS/ARI also believed, 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. (R.D., p. 592).

The PRA asserted that Duquesne's proposal to deny Rule 4 customers' access to a competitive retail generation market is in violation of the law and PECO Energy's underlying decision. Therefore, it must be rejected. (R.D., p. 593).

Enron argued that, in PECO Energy, supra, at page 117, 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." Enron submitted that all of the standards established at PECO, supra, at pages 117-118, 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. (R.D., pp. 593-598).

2. ALJ's Recommendation

The ALJ noted that, on the subject of special customer classes, the Commission, in PECO Energy, Slip Op. at 116, stated that Section 2804(7) requires that the Commission implement the Act "in a manner that does not unreasonably discriminate against one customer class to the benefit of another." The Commission acknowledged its obligation to consider the special circumstances of several customer classes to ensure that all customer classes receive a fair opportunity to benefit as intended by the Act.

The ALJ further noted that Section 2804(3) provides that "the Commission shall require the unbundling of electric utility services, tariffs, and customer bills to separate the charges for generation, transmission and distribution." However, several tariffs serving special customer classes were designed without granting the customers an opportunity to choose an alternative generation supplier. In such instances, the Commission found in PECO Energy, supra, at page 117, that it will, as a general rule, attempt to treat all of these customer classes the same as all other customers with respect to transmission, distribution and generation services provided by PECO Energy. The Commission determined that all existing tariffs, including special contracts, shall remain available throughout the transition period, except as modified in that Opinion and Order so that each customer could continue to receive the economic benefits of these tariffs.

The ALJ further noted that existing contracts containing language covering the future availability of competitive generation services will be governed by the terms of the contracts. Existing customers under contracts that are silent concerning future opportunities to choose competitive suppliers will be permitted to enter into separate generation contracts.

Regarding CTC payments by special customer classes, the ALJ observed that, pursuant to Section 2808(a) of the Act and PECO Energy, supra, no contract or tariff may permit a customer to bypass payment of the full CTC. To achieve that end, the ALJ determined that it may be necessary to provide a "comparable dollar value offset" on regulated transmission, distribution and generation rates. (R.D., p. 598).

The ALJ determined that Duquesne's contracts and tariffs for special customer classes should be modified to comply with the requirements of PECO, supra, and Section 2808(a) of the Act, 66 Pa. C.S. §2808(a).

3. Parties' Exceptions

In its Exceptions, Duquesne contends that the "offset" which the ALJ determined may be necessary to ensure that no customer bypasses payment of the full CTC as it applies to regulated transmission and distribution rates would be contrary to the Act, confiscatory, and preempted by the Federal Power Act as it applies to transmission or ancillary service rates. Duquesne submits that the only lawful result is to extend the transition period for customer classes that cannot complete payment of their allocated share of stranded costs before the year 2005. (Duquesne Exc., pp. 35-36).

In its Exceptions, the OCA contends that the ALJ's recommendation that stranded costs are to be allocated based on the utility's production plant allocator used in the Company's last base rate case does not specifically address the situation where such an allocation results in a CTC that violates the generation cap for discounted rate customers. The OCA argues that this determination should be clarified regarding Rule 4 Contracts. (OCA Exc., pp. 20-21, R.Exc., p. 20-21).

4. Resolution

In considering this issue, we concur with the ALJ's recommendation to specifically direct Duquesne to unbundle its contracts for distribution, transmission and generation CTC charges. This is required by Section 2804(3) of the Act, which states:

> The commission shall require the unbundling of electric utility services, tariffs and customer bills to separate the charges for generation, transmission and distribution. The commission may require the unbundling of other services.

(66 Pa. C.S. §2804(3)).

In PECO Energy, supra, we stated, at pages 117-119, that, as a general rule, we intended to treat these special rate classes in the same manner as all other customer classes with respect to all regulated rates and services, including CTC obligations. We further stated that our goal was to permit customers to continue to receive the economic benefits of the existing contracts until the CTC expires. We acknowledged that Section 2804(2) of the Act requires that interruptible options must be available. We determined that an EDC must file tariffs for distribution and transmission service applicable to customers in all classes who choose to shop. This applies in the proceeding now before us, as well.

We further determine, consistent with PECO Energy, supra, at page 119, that existing contracts containing language covering the future availability of competitive generation services will be governed by the terms of the contracts. Where those contracts are silent regarding future opportunities to chose competitive suppliers, the customers will be permitted to enter into separate generation contracts. Realized CTC charges should be computed and reconciled by tariff class.

B. Riders 8, 9 and 20

1. Positions of the Parties

Duquesne noted that it offers the following three economic development tariff riders: (i) Rider 8, which offers discounts for incremental consumption by existing industrial customers; (ii) Rider 9, which offers discounts for new load from large new customers; and (iii) Rider 20, which offers discounts for both incremental consumption by existing commercial customers and new load from new commercial customers.

(Duquesne St. 6, p.16). Duquesne has proposed to eliminate the discounts for incremental load from existing customers (Rider 8 and part of Rider 20), but not discounts for new load from new customers. (R.D., p. 599).

DII asserted that Duquesne proposes to eliminate the economic development incentive rates currently available to existing customers in Tariff Rider 8 "Industrial Economic Development Rider for Customers at Existing Service Locations" and Tariff Rider 20 "Small Business Development Rider." Duquesne Light Company Supplement to No. 4 to Tariff Electric Pa. P.U.C. No. 17, issued May 28, 1997, pp. 71-76 & 100-103 (hereinafter "Duquesne Tariff"). According to DII, these rates are proposed to be phased-out as customer contracts expire over the next five years. (Duquesne St. 6 at 18). DII submitted that this phase out is clearly inappropriate under the Act and must be rejected, since Chapter 28 guarantees that the generation component of rates is capped at the January 1, 1997, level for the entirety of the transition period. 66 Pa. C.S. §2804(4)(ii). (R.D., pp. 600-601).

The PRA also argued that Duquesne's elimination of these economic development incentive rates currently available to customers is in violation of the Act in that it increases the customer's rate above the rate cap imposed on January 1, 1997. Moreover, PRA contended that Duquesne's action is inappropriate when considered in light of its discriminatory treatment of providing special treatment to new customers at new service locations by authorizing access to the competitive retail generation market far earlier than existing customers. (R.D., p. 604).

2. ALJ's Recommendation

The ALJ noted that, in PECO Energy, supra, page 119, the Commission observed that these contracts provide rate discounts in order to retain or expand customers or load as competitive pressures limited the EDC's ability to continue to charge fully regulated rates. In recognition of the increasing competitive pressures that led to adoption of the Act, the Commission approved such tariffs or individual contracts provided the EDC received at least the marginal cost of service and no foregone revenues were shifted to other customers.

The ALJ determined that, since all existing customers under a special discount contract will have the opportunity to fully shop for generation no later than the final phase-in on January 1, 2001, the Commission should approve Duquesne's proposal to phase out these special customer discount contracts as they expire over the next five years, provided the affected customers are fully phased in to direct access to the generation market at the time of contract expiration. The ALJ further determined that the Company's offering of special discount contracts to new customers or existing customers with new load constitutes discriminatory treatment proscribed by the Act. 66 Pa. C.S. §2804(7). The ALJ concluded that Duquesne can acquire new customers or new load in the competitive generation marketplace. For these reasons, the ALJ recommended approval of the Company's proposal for Rider 8, as herein modified, and denial of the Company's proposal for Riders 9 & 20. (R.D., pp. 604-605).

3. Parties' Exceptions

In its Exceptions, Duquesne contends that the ALJ erred in recommending not to permit Duquesne to offer special discount rates to new customers or existing

customers with new load. Duquesne argues that the ALJ's characterization of these contracts as providing discounts is erroneous because these contracts apply to load that would not otherwise by served by Duquesne. (Duquesne Exc., p. 36).

In its Exceptions, DII contends that the ALJ's recommendation to phase out economic development incentive rates available to existing customers is contrary to the Act. DII submits that the Act requires that these rates remain available during the entire transition period. DII further argues that, contrary to the ALJ's determination, in PECO Energy the Commission required that PECO continue to offer existing economic development rates throughout the transition period. (DII Exc., pp. 8-9).

4. Resolution

In considering this matter, we note that, with respect to special customer classes, all tariff classes should be unbundled, permitting all customer classes to procure generation competitively. All existing contracts shall remain in effect on their terms. A contract that explicitly prohibits shopping in contemplation of the passage of the Act shall remain unchanged. However, any customer with a contract that does not explicitly prohibit shopping must be permitted to shop. Upon expiration, contracts need not be extended, but the rate caps remain applicable as provided in Section 2804(4).

No contract may permit bypass of the CTC. Any existing contract purporting to do so must assign customer payments to full recovery of the allocated CTC and provide the associated discount as a credit to the customer against other portions of the bill. As rates are unbundled, customers with existing discounts must receive an allocated discount to the T&D portion of the bill unless the nature of the discount is exclusively on the generation component.

Accordingly, we will approve Duquesne's proposal for Rider 8, as modified, but will deny Duquesne's proposal with respect to Riders 9 and 20.

C. Self-Generation

1. Net Metering

(a) Positions of the Parties

Duquesne's Restructuring Plan did not include net metering. The Environmentalists argued that Duquesne should be required to implement a net metering tariff for renewable energy and fuel cell projects. (R.D., pp. 605-607).

(b) ALJ's Recommendation

The ALJ recommended that the Environmentalists' proposal for using a "net metering" arrangement should be rejected as violating the Act's mandate for a non-bypassable CTC. 66 Pa. C.S. §2808(a); PECO Energy, Slip Op. at 124. The ALJ further recommended that the remaining issues raised by the Environmentalists should be more appropriately considered in generic proceedings. (R.D., p. 607).

(c) Parties' Exceptions

In their Exceptions, the Environmentalists contend that the ALJ erred in recommending the rejection of the Environmentalists' proposal. The Environmentalists argue that Duquesne does not currently have a net metering tariff and should be directed

to implement one for renewable energy and fuel cell projects by any customer class which is 10 kw or less. (Environmentalists' Exc., p. 6).

(d) Resolution

In considering this matter, we note that the ALJ rejected the Environmentalists' proposal to require Duquesne to implement a net metering based tariff for renewable energy and fuel cell installations which have a capacity of 10 kw or less. The ALJ determined that this proposal conflicted with Section 2808(a) of the Act regarding a *non*-bypassable CTC. We observe, however, that Section 2808(a) is conditioned upon significant reductions in the purchases of electricity. Section 2808(a) states, in relevant part;

> ...If a customer installs on-site generation which operates in parallel with other generation on the public utility's system and which significantly reduces the customer's purchases of electricity through the transmission and distribution network, the customer's fully allocated share of the transition or stranded costs shall be recovered from the customer through a competitive transition charge.

In our opinion, it is unlikely that the size of these installations will materially affect the recovery of stranded costs by the Company. Therefore, in order to remove a barrier to the development of these small installations, we direct Duquesne to include a net metering based tariff schedule consistent with the Environmentalists' proposal.

2. Interconnections

(a) Positions of the Parties

The Environmentalists argued before the ALJ that several changes to the interconnection provisions of Duquesne's proposed tariff should be made. The Environmentalists contended, among other things, that the technical standards should be simplified and the cost of engineering review for small projects should be capped at $35, and for other installations, at $250. (R.D., pp. 606-607).

(b) ALJ's Recommendation

The ALJ recommended that this interconnection issue should be addressed in a generic proceeding. (R.D., p. 607).

(c) Parties' Exceptions

In its Exceptions, the Environmentalists argue that the ALJ erred by not requiring Duquesne to change its interconnection tariff as proposed by the Environmentalists. The Environmentalists contend that these changes are designed to remove unnecessary barriers to interconnection. (Environmentalists' Exc., pp. 6-7).

(d) Resolution

In considering this matter, we note that Section 2804(2) provides that restructuring shall permit "reasonable and fair opportunities to self-generate and interconnect" to the transmission and distribution system. Duquesne made no proposals

to address this statutory directive in its restructuring plan. Consistent with PECO Energy, supra, we conclude that Duquesne must provide reasonable opportunities for both large and small customers to interconnect self-generation. We adopt the proposals of the Environmentalists in this regard, except that we do not require Duquesne to purchase the generation of any customer. With customer choice and direct access, a self-generating customer may contract to buy and sell electricity with any willing EGS. Duquesne must, however, as an EDC, provide the opportunity for self-generation through reasonable net metering and interconnection provisions.

D. Other Tariff-Related Issues

1. Positions of the Parties

As noted by the ALJ, DII contended that three other tariff-related issues must be addressed in this proceeding. DII observed that Duquesne proposes changes to its current tariff for Interruptible Service (Rider 7), Time-of-Day Service (Rider 5) and High Voltage Power Service (HVPS). DII submitted that these proposed changes are inappropriate and must be rejected. DII asserted that all of Duquesne's tariff offerings must remain intact throughout the transition period in order to provide customers with the rate cap protection mandated by the Act. 66 Pa. C.S. §2804(4). (R.D., p. 608).

(a) Interruptible Service (Rider 7)

DII asserted that Duquesne submitted a tariff for Interruptible Service that makes two significant changes to the rate. (Duquesne St. 5, Exh. JAL-12, pp. 95-97; compare, Duquesne Tariff at 68-70). According to DII, both changes are unreasonable

and not necessary to introduce the competitive generation supply option to Duquesne's service territory. (DII M.B., p. 93).

DII observed that Duquesne's proposed tariff rider for Interruptible Service contains the following provision:

> Customers must contract under this rider prior to December 31, 1998 and must take full service from the Company as defined in the applicable rate schedules to qualify.

(Duquesne St. 5, Exh. JAL-12 at 95). DII contended that this provision places two restrictions on the availability of Interruptible Service, neither of which is in the current tariff. Duquesne Tariff at 68-70. Namely, those restrictions are the requirements that customers must contract under this rider prior to December 31, 1998, and must take full service as defined in the appropriate rate schedules. Therefore, DII asserted that these restrictions are inappropriate and must be rejected. (R.D., p. 608).

(b) Time-of-Day Rates (Rider 5)

DII noted that Duquesne proposes to restrict the availability of Time-of-Day service (Rider 5) to customers that contract prior to December 31, 1998. (Duquesne St. 5, Exh. JAL-12 at 92). DII observed that this restriction is not present in the current tariff and contended that this change is unreasonable and must be rejected for the reasons stated in the previous section. (R.D., pp. 610-611).

(c) HVPS Tariff

DII contended that the Company's proposed tariff omits the provision in the HVPS tariff with regard to "Generation Avoidance" energy. DII asserted that this generation avoidance is designed to permit an HVPS customer that produces a portion of its energy requirement for its own use with internal generating equipment to purchase electricity from Duquesne and avoid the use of alternative energy sources when its equipment fails. (DII St. 1, p. 57). DII contended that the Company acknowledges that generation avoidance was inadvertently omitted and agrees to reinsert the provision in the final tariff to be submitted as part of the compliance filing in this proceeding. (Duquesne St. 5-R, Exh. JAL-14 at 19). This reinsertion of the provision alleviates DII's concerns with respect to Generation Avoidance in this part of the proceeding. (DII St. 1-S at 14). DII recommended that the Commission require the Generation Avoidance section to be reinserted in the compliance filing by Duquesne in this proceeding. (R.D., p. 611).

2. Recommendation

The ALJ recommended that, for the reasons advocated by the DII, the Commission should deny the Company's proposed changes to its current tariffs for Interruptible Service (Rider 7), Time-of-Day Service (Rider 5) and High Voltage Power Service (HVPS).

3. Parties' Exceptions

In its Exceptions, Duquesne does not object to the ALJ's recommendations regarding Rider 7, but requests clarification, so that it is understood that the interruptible credit applies only to the load that Duquesne can interrupt.

4. Resolution

In considering this issue, we note that Section 2804(4) of the Act requires that all tariff offerings must remain intact throughout the transition period in order to provide customers with the rate cap protection mandated by the Act. Only tariff changes necessary to unbundle rates and introduce competition for generation supply are appropriate during the transition period while customers are captive to the payment of a CTC. We are not persuaded by the record in this proceeding that Duquesne's proposed changes to its current tariffs for Interruptible Service (Rider 7), Time-of-Day Service (Rider 5) and High Voltage Power Service (HVPS) are consistent with Section 2804(4) of the Act. Accordingly, we shall adopt the ALJ's recommendation to deny Duquesne's proposed changes to these current tariffs.

E. Summary

In this Section, with respect to Rule 4 Contracts, we specifically directed Duquesne to unbundle its contracts for distribution, transmission and generation CTC charges. With respect to Riders 8, 9, and 20, we determined that all special customer tariffs should be unbundled so that all customers can procure competitive generation. Regarding self-generation, we directed Duquesne to include in its compliance filing a net metering tariff. Regarding interconnections, we determined that Duquesne must provide reasonable opportunities for both large and small customers to interconnect. Finally, with respect to Interuptible Service (Rider 7), Time of Day Service (Rider 5), and High Voltage Power Service (HVPS), we denied Duquesne's proposed changes to these tariffs.

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