NEV STATEMENT NO. 1

8/28/97
1Hbg Jan

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application of Pennsylvania Power & Light Company For Approval of Its Restructuring Plan Under Section 2806 of the Public Utility Code	: : :	Docket No. R-00973954

DOCUMENT FOLDER

DIRECT TESTIMONY
OF
DAVID MAGNUS BOONIN

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Regarding Generation Rate, CTC's, Unbundling of Certain Bundled Tarriffs and Billing Issues

Q. Please state your name, title and business address.

A. My name is David Magnus Boonin. I am President of New Energy Ventures, Mid-Atlantic. My business address is 1845 Walnut Street, Suite 2525, Philadelphia, PA 19103.

Q. Please describe New Energy Ventures (NEV).

A. NEV is the organizer and manager of a buyers' alliance for retail energy. Our business is saving our members money on their energy bills. In this proceeding and elsewhere, we work for our members and potential members. We have offices in California, Boston, New York and Philadelphia. We are a certified FERC Power Marketer and are a registered provider of retail electricity in California. NEV has a license application pending in Rhode Island and has applied for a membership in the New England Power Pool. We are currently preparing our license application to submit in Pennsylvania.

Q. Please describe your education and experience.

A. Since graduation from The Wharton School in 1973, I have spent almost my entire career in the fields of utility planning, management and policy. A copy of my resume is attached as NEV/DMB Exhibit #1. Some of my positions prior to joining NEV including serving as Chief Economist for the Pennsylvania Public Utility Commission, Commissioner and Executive Director of the Philadelphia Gas Commission and Supervisor of Economic and Energy Forecasting for a major electric utility. I also headed my own consulting practice. Among the issues I addressed on behalf of my clients was the issue of the restructuring of the utility industry. I have had extensive experience in designing adjustment clauses under section 1307 of the 66 Pa.C.S.A. I have also presented or had published numerous papers and have testified before regulatory and legislative bodies on utility and regulatory issues.

Q. What is the purpose of your testimony?

A. The main purpose of my testimony is to present an approach for the unbundling of the cost of generation which is consistent with Act and allows for the development of a competitive market for electricity. I have also identified tariffs and riders where PP&L still needs to provide for unbundled generation. In addition, I will also address the billing issue of the definition of the term customer in the deregulated market.

UNBUNDLED RATE FOR GENERATION

Q. Please summarize your approach to establish an unbundled price for generation.

A. I propose that the unbundled price for generation is to be determined by the market. This is necessary in order to make choice a reality for retail customers while treating all affected parties equitably. In this newly competitive world, generators will be afforded the opportunity to sell their power on a power exchange. The price for generation should be determined by the market-clearing price of the power exchange, adjusted for the costs of retail delivery. To make this comply with rate cap, I also recommend that the unbundled charge for electricity and the CTC always be kept in balance so that the total of the two never varies.

Q. You mentioned that the unbundling methodology should comply with the law. What does the statute state?

A. Section 2802 (14) of the statute states in part:

"The generation of electricity will no longer be regulated as a public utility function."

Section 2804(3) of the statute states in part:

"The Commission shall require the unbundling of electric utility services, tariffs and customer bills to separate the charges for generation, transmission and distribution."

Section 2808(E)(3) of the statute states:

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

Q. Why is Section 2808(E)(3) important?

A. Section 2808(E)(3) determines the price the electric distribution utility (EDU) may charge for generation to any user other than those who have chosen an alternative generation supplier. This section sets forth that the EDU (or someone else designated by the Commission) shall provide this service at "prevailing market prices" and be fully compensated. As the price of generation is otherwise deregulated by the Act and is to be unbundled, it is precisely this language which sets the unbundled price of generation which may be charged by the EDU.

Q. You also mentioned that the unbundled price of generation should be based on certain market principles. Please explain.

A. In practice, the price of generation varies from hour to hour across the year. Fixed prices established through regulation, even those with demand charges and/or time-of-use pricing will only reflect the actual price of generation by happenstance. This is the fundamental practice under the existing regulatory paradigm. In the new competitive environment, electricity is being turned into a commodity whose price shall vary depending on market conditions. Therefor, appropriate unbundled price of generation should also vary with the market and not be fixed.

Q. Why is a variable versus a fixed price of generation more appropriate?

A. For the Commission to estimate and establish a fixed price for generation in an unbundled, full service tariff it must make and lock in numerous assumptions. Generally, when estimating a price, "normal" assumptions are made about weather, fuel, prices, economic conditions, supply availability, etc. These assumptions are for extended periods. There is almost no possibility that these normal estimated costs will produce a price at prevailing market rates at every time let alone at most times.

In contrast, a variable price can change with market conditions and frees the Commission from the impossible task of accurately predicting the prevailing market price of generation. This approach is also consistent with the intent of the legislation which is to deregulate the price of generation, not to reestablish a regulated price of generation on a different concept than historical rate base regulation.

Q. What is your proposal for the unbundling of generation in the EDU's tariff?

A. I propose inserting the following language in each tariff for individual classes of customer:

"The unbundled rate for generation shall be established by the power exchange market clearing bid price for generation, fully adjusted for ancillary services necessary to convert wholesale generation into reliable, deliverable retail power at market determined or FERC approved prices which may be required by the independent system operator (ISO), including but not limited to, capacity, spinning reserves, load balancing and as further adjusted for losses associated with the voltage level of delivery and location."

This language would be further enhanced after the final establishment of a power exchange (PX) and/or independent system operator (ISO) and their establishment of final governing rules. As the establishment of an ISO and PX is necessary for retail competition to function, waiting to enhance this language should not in and of itself cause significant delays.

This language establishes the basis for determining the prevailing market price for retail generation at any point in time.

To understand this approach it is necessary to understand several concepts. First that power exchange establishes the wholesale price for energy by establishing a market price for electricity based on wholesale bids. Second, there are services, such as load balancing, spinning reserves, etc. which have costs, which are necessary to convert this wholesale energy into retail electricity. Third, losses associated with the transmission and distribution of electricity may cause the retail price for power to vary depending on the level of voltage delivery. Fourth, at certain times of the year, even within an EDU's service territory, locational price differences may occur, depending on physical limitations and/or FERC pricing decisions.

Q. Please explain why the power exchange price establishes the wholesale price for electricity.

A. The PX will continually solicit bids from wholesalers to meet current demands. The highest price bid used during a period (probably hourly) will set the prevailing wholesale market price for energy at that time. The process of matching supply and demand will be repeated continually during the day with a new wholesale market prevailing rate established (probably hourly). This bid process will replace the current economic dispatch system currently used by many utilities and power pools. It allows all willing suppliers to bid for the right to supply the demand that exists, excluding what has been met by bilateral contracts. There may be exceptions for plants that are dispatched for reasons other than price (e.g. system balancing). These exceptions will be known and can be treated like other ancillary services needed to convert wholesale service into retail service.

Q. Please explain why and how these services need to be adjusted to reflect reliable, deliverable retail electricity.

A. The supply and demand of electricity are subject to many stochastic events. Power plants are forced off-line. Customers turn electricity consuming equipment on and off unexpectantly and randomly. Because of this, it is not enough to use the wholesale PX price as the total power exchange price. It is also necessary to include costs associated with converting that energy into reliable retail electricity. The ISO shall determine rules of what ancillary services a supplier must provide. These services may include but are not limited to: capacity, spinning reserve and load balancing. These services are the types that are generally necessary to convert wholesale power into reliable electricity. These services will either be priced at a set price by the ISO and FERC or through the market (my preferred approach).

Q. Please discuss the adjustments that are necessary due to voltage differences.

A. Power delivered at declining voltages experience greater losses. An adjustment factor should be applied to each voltage delivery level to reflect these differences.

Q. Please discuss the adjustments that are necessary due to the location of the customer.

A. Sometimes, due to transmission limitations, power prices within a power exchange may differ at different locations. If the ISO identifies such limitations and establishes the need to have different pricing in different regions, then individual prevailing market clearing prices may need to be established for certain sub-regions at certain times.

Q. Why is this adjusted power exchange price an accurate proxy for prevailing market prices?

A. This is the way goods and services in the market are usually priced. The power exchange adjusted for retail delivery starts with a prevailing wholesale market price and adds the costs necessary to convert it to the retail service.

Q. Under your proposal, how often will the prevailing market price change?

A. It will change as often as the components discussed above cause a change. Practically, I see the prevailing market price changing hourly, much as today's power pool price (or system lambda) changes today.

Q. Given that the prevailing market price may be changing hourly, what type of metering will be necessary?

A. That will be up to the individual supplier and the ISO rules of load balancing. In general, I anticipate that hourly meters will be necessary for larger loads, regardless of whether the generation supplier is the EDU or another supplier. Small loads, such as residential and small commercial customers may be able to be metered as currently done, if the ISO permits the use of a standard load curve(s) for load balancing purposes.

Q. How do you anticipate customers being billed?

A. Each individual customer with hourly meters would be billed based upon the full prevailing retail market price for each kilowatt consumed in that hour. Demand billing and ratchets should become unnecessary following this approach for generation.

Capacity charges would be charged during the hour that the customer imposed the need. Small customers without hourly meters who have an acknowledged and approved load shape would be billed based upon the their kWh usage spread over the load shape, using the prevailing market prices at the time. Customers who do not have approved load shapes and do not have hourly meters would be charged for unallocated imbalances, as reflected for their reliance on the ISO rather than their own supplies. This creates de facto hourly pricing.

Q. Do these load shapes need to be determined at this time?

A. No. I believe this would be premature. The Commission to the ISO should recommend them after the ISO indicates a willingness to address load imbalance responsibilities based upon load shapes for some subset of customers.

Q. Given the variable nature of your proposed approach to unbundling generation, how will you have your approach comply with the rate cap?

A. I propose keeping the total of the unbundled price of generation and the generation related portion of the CTC constant. If the prevailing market price increases so does the unbundled charge for generation with an equal decrease to the generation portion of the CTC.

Q. Why is this appropriate?

A. Under most approaches to determining stranded costs; there is a relationship between the prevailing market price for generation and the competitive transition charge. All else being equal, if one were to assume an increase in the value of generation because the market price of generation increased, then the stranded costs would decrease by the same amount. Likewise, if the market price of generation were to decrease, the value of the generation would decrease and stranded costs would increase.

Stranded costs are the core of the calculation of the Competitive Transition Charge (CTC). At a particular point in time (eliminating discounting and levelization) there is a one to one relationship between a change in the value of generation and an opposite but equal change in stranded costs.

Q. In general, how would this work?

A. Because of this one to one relationship, it is recommended that in establishing the unbundled rates for generation and CTC that the Commission follow the following protocol.

- Determine stranded cost, the CTC and ITC for each rate class as appropriate.

- Stranded costs, the CTC and ITC should be split between generation and non-generation related costs.

- Explicitly determine the related underlying assumed market price for generation associated with the generation portion of the CTC for each rate class. The price of generation could be levelized, but it is recommended that it be desegregated at least by year.

- The EDU would compare the average weighted prevailing market price for generation for each customer class for the billing period with the underlying assumed market price for generation.

- The generation related portion of the CTC would then be adjusted so that the total of the adjusted CTC and the prevailing market price for the period would always be equal to the base CTC and underlying assumed price of generation.

This approach is consistent with section 2804(8)(II), which joins the CTC, ITC and the unbundled price of generation.

Q. Please explain why and how you are splitting the CTC.

A. The Act at Section 2808 discusses generation related transition costs separately from other transition costs. Following this lead, I recommend that the Commission split the CTC into two categories, generation and non-generation. This allows for the generation portion of the CTC to be used as offsets to variation in the prevailing market price as discussed above. This charge should be set only on a kWh basis. Hourly allocations of generation costs should negate the need for demand charges and ratchets. I do not have an opinion at this time on the rate design for the non-generation portion of the CTC.

Q. Would you please provide a simple example of how your proposal would work?

A. Yes. Assume for purpose of illustration that the base generation related CTC established by the Commission is 1.5 cents/kWh and the associated estimated market price/value of generation is 2.9 cents per kilowatt-hour for a total of 4.4 cents. Assume also that in a given month the actual prevailing market price is 2.7 cents. This is 0.2/kWh cents less than the estimated market price that is the basis for determining the CTC. The CTC would therefore be increased by the same amount for bills rendered for that period or to 1.2 cents per kilowatt-hour. Under either case the combined total will still be 4.4 cents/kWh.

If the opposite were true and the prevailing market price were to exceed the estimated market value of generation, then the CTC would be decreased.

This self balancing process assures that the generation charges are always in compliance with the rate cap provisions of the Act.

Q. Have you considered how the Commission would go about reconciling the ITC and CTC consistent with sections 2808(F) and 2812(B)(5) of the Act, given your variable methodology?

A. Yes.

Q. Why is it necessary and appropriate for the Commission to establish a reconciliation methodology at this time?

A. The Commission in its April 10, 1997 order on periodic adjustment of the CTC and the ITC stated that "only during the course of the evidentiary hearings can such matters as the appropriate CTC/ITC calculation and reconciliation methodology be determined as well as the appropriate format, content and necessary supporting information associated with the annual CTC reconciliation's and periodic ITC adjustments."

Q. Please summarize your reconciliation methodology.

A. I propose a reconciliation method which individually reconciles the Competitive Transition Costs associated with generation and non-generation related costs. Non-generation costs would only be reconciled based on changes in absolute levels of recovery caused by variations between forecasted and actual sales. Generation related costs would also be adjusted for variations in sales but only after an adjustment is made to the required level of amortization to reflect changes in the prevailing market price. I have also proposed, as a general rule, deferring adjustments for over or undercollections to the end of the transition period.

Q. Have you provided a more detailed description of your proposed reconciliation methodology?

A. Yes. It is attached as NEV/DMB Exhibit #2.

Q. In your proposal, does it matter whether the sales are billed directly by PP&L or whether PP&L provided the generation service?

A. No. All customers in a given rate class should pay the same CTC rate(s).

Q. How does this work with a utility like PP&L who is trying to recover its CTC partially on an energy and partially on demand basis?

A. Non generation related costs could still be recovered in a fashion similar to PP&L's proposal. As I stated earlier, I have not yet developed an opinion in the appropriate rate design for this item, nor is it germane to my proposal. All generation related charges would be recovered on a kWh basis. Actual or imputed load shapes would assign actual prevailing rates to each customer. Demand ratchets would be eliminated for these portions of these services as would cross subsidization for generation. Customers would pay only for the load the actually placed on the system.

Q. Would the CTC change for all customers or only those receiving full services from the EDU?

A. The CTC would change for all customers.

Q. Why should the CTC change for all customers based upon prevailing market prices for generation?

A. The CTC is a charged being imposed on customers regardless of whether they stay with the EDU or seek energy services form an alternative supplier. The CTC should be the same for similar customers who are served by the utility at the prevailing market rate or by an alternative provider at a market-determined rate.

Q. How does your proposal for establishing a prevailing market price for generation compare with those of PP&L?

A. Both proposals recognize that the statute requires PP&L (or some other Commission designated supplier of last resort) to establish a price for generation services equal to the prevailing market price. I believe that my proposal for establishing the price for generation service, complying with the rate cap, splitting the CTC into two components and reconciling the CTC are natural extensions of the positions offered by PP&L's witnesses in this case.

Where PP&L acknowledges the tie between the market value for generation and stranded costs and the CTC, so does my proposal. I, however, create the direct linkage between these elements.

PP&L acknowledges that it must charge the prevailing market rate for electricity to those seeking a fully bundled service. PP&L leaves the determination of this price for later. My proposal, recognizing that there are still rules to be determined by the ISO, takes significant steps to defining this price.

PP&L acknowledges that stranded costs fall into two general categories, generation related and non-generation. My proposal actually separates these two components to produce the flexibility necessary to achieve market-based prices for generation, comply with the rate cap and recover a reasonable assessment for stranded costs.

Although PP&L acknowledges the close interrelationship between changes in the market price of generation and stranded costs, they stop short of reconciling these differences. Although I agree that no one is served by reopening the stranded cost issue annually, I also believe that everyone is served by adjusting the amortization schedule to reflect changes in the market. Without this, everyone is building their transition plans on mere estimates and speculation of future market conditions.

Q. Is your approach consistent with the statute and Commission orders and regulations?

A. A discussed in more detail above, yes.

Q. Can this approach be used for any utility.

A. Yes.

Q. Will people know the price of electricity before they consume it.

A. Yes. Customers electing to stay with the EDU for full service would know the price of generation before it is consumed although there may be shifting between the subparts of the CTC and generation.

Q. Does the proposed approach guarantee the recovery of allowed stranded costs?

A. Yes as annually adjusted to reflect actual market conditions. It is, therefore, a more accurate approach than one which is based upon an estimate of market prices.

Q. How would securitization work under your proposal?

A. I recommend that in order to meet the revenue guarantees associated with securitization that the Commission only allow to be recovered through the ITC costs which are either not dependent on changing market conditions and/or extremely conservative estimates of stranded costs which are influenced by generation. It may be possible however to use unexpected revenues from a higher than expected prevailing market price to support securitized stranded costs. If this is done, the Commission could securitize even a liberal estimate of generation related stranded costs.

Q. You have developed a detailed approach for unbundling. How should the final tariffs be developed?

A. I recommend that the Commission direct PP&L to submit tariffs consistent with this approach and with the Commission's findings. A CTC (which could be split between generation and non-generation) will need to be provided by PP&L as compliance filing with the Commission's final order. The Commission should explicitly state for each class of customer the assumed prevailing market price(s) for generation used in developing its stranded cost findings so that the adjustment mechanism I propose can be followed. A good first step would be to have PP&L complete the table I have laid out in my Exhibit #2.

TARIFFS AND RIDERS WHICH ARE NOT UNBUNDLED

Q. Has PP&L fully unbundled all of its tariffs and riders?

A. No. As discussed by M. Kasper in his testimony, PP&L has limited the unbundling of several tariffs and riders.

Q. Please list these tariffs and riders.

A. These include the:

Economic Industrial Development Initiative (EDI/IDI) Riders
Demand Free Days Rate Options
Competitive Rate Rider
Time-of-Day Rate Option
Rate Schedule PR-1 and 2
Interruptible Service

Q. What is PP&L's general approach to these riders?

A. PP&L is generally only offering these rate options to their full service customers and is phasing-out these rate provisions.

Q. Does this comply with the law?

A. No. The Act requires that all rates be unbundled.

Q. What do you propose?

A. I propose that PP&L be required to offer these special rate provisions and discounts to the eligible customers for the eligible period, regardless of the supplier of energy. Customers would still need to meet the requirements of tariff. PP&L has proposed extending some of these programs, claiming that it is necessary for revenue neutrality. It may protect this class of customer from a rate increase, but it also freezes out competition.

Q. What is your recommendation?

A. I recommend that PP&L file modifications to these riders which are designed to remove the anti-competitive provision of availability only to full service customers. If PP&L is unwilling to remove this anti-competitive provision, it should be required to phase out these provisions by January 1, 1999.

BILLING AND THE DEFINITION OF A CUSTOMER

Q. Please summarize your testimony in this area.

A. Many customers have service on multiple meters throughout an EDU's service territory. These customers are currently discriminated against when compared to customers with similar loads served through a single meter. I propose that alternative generation providers be permitted to treat these customers as a single service for purposes of billing for transmission and CTC related charges.

Q. Why did you exclude generation from your earlier response?

A. The price of generation is deregulated and the EDU already has the right to issue a customer a bill for its generation services on a consolidated basis. No Commission action is required.

Q. Why did you exclude distribution charges?

A. This is a conservative proposal. Customers with multiple meters may impose a cost on the system that is different than a similar load from a single location associated with the distribution of the service. It is therefore recommended that these specific charges be billed as they are currently.

Q. How are transmission and CTC different from the distribution charges?

A. Transmission and CTC related charges should not change with the number of installations or meters but with the load placed on the system.

Q. Why does defining a customer by a meter discriminate against someone who receives service at multiple meters?

A. I will answer that question with an example. Assume that there is a customer with a single meter and a load of 2 MW. Assume also that there is someone else with three meters, all on the same tariff as the first customer, whose coincidental load totals to 2 MW but whose non-coincidental load is 2.5 MW. This second customer places the same type of non-distribution related load on the system but is being charged more than the first customer. All of these customers are on the same rate schedule and all have the same coincidental peak, but the multi-site customer is being irrationally discriminated against.

Q. In your example, you stated that all of the customers were on the same rate schedule. Would you make that a pre-condition of your bill consolidation proposal?

A. Yes. For administrative ease, if for no other reason, this consolidation should only be for customers of record who have multiple meters on the same rate tariff.

Q. How does this issue fit into this debate on competition?

A. Without competition this would not be as germane. Competition brings with it innovation. More and more customers will be metered such that hourly loads can be determined, a necessary request for consolidated billing. Competition also challenges the necessity of demand based billing, particularly if customers are paying for the burden they place upon the system virtually on an hourly basis. Competition also highlights the importance of electric prices in economic competitiveness. It is no longer acceptable to shrug when the type of blatant discrimination is pointed out and say that's they best we can do. Yesterday's good enough is no longer adequate.

Q. Specifically, what is your proposal?

A. My proposal is:

1. as testified by others, alternative generation providers should be allowed to issue bills for all parts of the electric service, including those charged by the EDU;
2. that an alternative generation provider be allowed to consolidate bills for customers with multiple meters within a single rate tariff;

3. that the consolidated bill will not have any impact on the distribution charge,

with the exception of unbundled services for metering, billing, collections and information which shall be competitive; and

4. that only through this modification can the Commission prevent undue competition from occurring between customers with identical loads on the same rate tariff.

Q. Does this conclude your testimony at this time?

A. Yes.

DAVID M. BOONIN

EDUCATION

Brown University, M.A. in Economics, 1976

Wharton School, University of Pennsylvania, B.S. in Economics, 1973

EXPERIENCE

New Energy Ventures, Inc., Philadelphia Pennsylvanaia

PRESIDENT, MID-ATLANTIC DIVISION, 1997 - Present

Manage NEV's Mid-Atlantic operations.

Consulting

PRESIDENT, THE BOONIN GROUP,/SENIOR ADVISOR, HAGLER BAILLY CONSULTING, 1992 - 1997

Provide strategic, policy and technical advice to utilities and others dealing with utility matters. Clients and assignments are diverse ranging from industries including: electric, gas, water and transportation and issues including competition, rates, restructuring, regulatory policy, etc.

City of Philadelphia, Philadelphia, Pennsylvania

EXECUTIVE DIRECTOR, PHILADELPHIA GAS COMMISSION, 1991 - 1994

Managed the Commission's technical and administrative staffs. Provided policy and strategic advice to the Commissioners. Interfaced with the public including: government officials, the press, interest groups, etc.

COMMISSIONER, PHILADELPHIA GAS COMMISSION, 1988 - 1991

Regulated largest gas utility in the State and largest municipal gas utility in the nation. Performed detailed budgetary and management review and oversight.

DIRECTOR OF UTILITY AND REGULATORY AFFAIRS, 1988 - 1991

Directed City's activities addressing utility and regulatory issues including the City as a large user, the City as a provider of utility services and the quality of the City's economic and physical environment. Scope of issues spanned fixed and transportation utilities as well as the insurance industry. Worked with regulators, utilities, interest groups and legislators.

DIRECTOR OF INTERGOVERNMENTAL AFFAIRS, Office of the Mayor, 1985 - 1988

Directed the City's legislative and administrative efforts with federal, state and local government, including the activities of lobbyists and Philadelphia's Washington Office. Addressed financial, economic and utility problems facing the City.

United Illuminating Company, New Haven, Connecticut

SUPERVISOR, ENERGY DEMAND AND ECONOMIC FORECASTS, 1983 - 1985

Corporate economist for a major electric utility. Managed department responsible for forecasting the utility's energy sales and peak demand. Developed energy resource strategies.

Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania

CHIEF ECONOMIST, 1979 - 1983

Managed the Economics Division. Developed policy recommendations, performed research and/or testified on regulatory, energy, economic, financial, rate and environmental issues

CHIEF OF THE ENERGY IMPACT ANALYSIS SECTION, 1978-1979

Managed interdisciplinary staff and projects concerning fixed utilities and energy. Developed and assessed regulations, rate structures and economic incentives.

ECONOMIST, CHAIRMAN'S STAFF, 1976 - 1978

Economic advisor to the Chairman of the Commission. Reviewed each rate case as well as other cases and offered specific recommendations on all facets of the case.

United Engineers and Constructors, Inc., Philadelphia, Pennsylvania

ECONOMIST, NUCLEAR TECHNICAL STAFF, 1973 - 1975

Analyzed issues relating to the costs/benefits, safety and licensing of power plants

SELECTED PROFESSIONAL ACTIVITIES

- Commissioner, Philadelphia Planning Commission (1990-1991)
- Member,Private Sector Advisory Panel on Infrastructure Financing, Senate Budget Committee (1986)
- Board Member, Energy Coordinating Agency (1988-Present)
- Energy, Environment and Natural Resources Policy Committee: National League of Cities (1990-1991)
- Community and Economic Development Committee; Pennsylvania League of Cities (1989-1991)
- Served on numerous committees and task forces, including: Electric Utility Efficiency Task Force, Pennsylvania Utility Advisory Committee, Statistical Research Committee - ECNE, Taxi Advisory Committee, Utility Consumers Council, EPRI and NEPLAN Committees

PERSONAL

- American Jewish Congress - Board Member
- B'nai Brith Anti-Defamation League - National Leadership Award 1991
- Central High School Board Alumni Association - Board of Directors
- Boy Scouts of America - Assistant Scout Master, Eagle Scout
- Born May 18, 1952, Philadelphia, Pennsylvania; Married

RECONCILIATION OF THE CTC

The Commission finds that the base stranded cost recoverable through the Competitive Transition Charge (CTC) is $____________. Of this amount $_______________ is not generation related and $_______________ is generation related.

The generation related portion is based upon, in part, estimated levelized value of generation of $0.0xxx cents per kWh.

The base Competitive Transition Charge is as set forth in each individual rate schedule. The CTC has been divided into non-generation and generation related components.

The CTC is designed to produce the listed amortization schedule for stranded costs, divided into non-generation and generation related costs.

COMPETITIVE TRANSITION COSTS BASE ANNUAL AMORTIZATION SCHEDULE				
Year	Total to be Amortized	Non-generation Related Costs	Generation Related Costs	Projected Sales
1999				
2000				
2001				
2002				
2003				
2004				
2005				

The CTC shall be reconciled annually consistent with section 1307(e) of 66 Pa. C.S.A. Reconciliation of over or under collections shall be collected by extending or shortening the CTC period, except as otherwise ordered by the Commission.

Non-generation related CTC shall be adjusted based upon the following formula.

$Nongen_{act} - Nongen_{amort} = E_{nongen}$

where:

$Nongen_{act}$ is the actual amount collected from all classes of customers during a year for non-generation related competitive transition charges;

$Nongen_{amort}$ is the amortization schedule for the same year for non-generation related competitive transition charges as shown in the schedule; and

E_{nongen} is the over or under collections associated with non-generation related stranded costs based upon the difference between the amortization schedule and actual collections.

This process shall be repeated annually throughout the amortization period until the total amount for non-generation related stranded costs, as shown in the table above, is collected.

Note: this methodology only produces over or undercollections of non-generation related CTC when projected sales vary from actual sales.

There shall be two types of adjustments made for generation related CTC:

an adjustment to the amortization schedule based upon differences between the base generation related CTC and the CTC based on the actual market value generation, and

an adjustment for the anticipated versus actual level of collection (similar to the adjustment for non-generation related CTC).

The first step is to adjust the amortization schedule for the year being reconciled. This shall be done according to the following formula.

$(CTC_{market} \times SALES_{projected}) - (CTC_{base} \times SALES_{projected}) = E_{amort}$

where:

CTC_{market} is the adjusted CTC charged to each class of customer to reflect the change in the value of generation from that used in the calculation of the base CTC. It is determined for each class of customer by the formula:

$CTC_{market} = CTC_{base} - (GENVALUE_{actual} - GENVALUE_{base})$

where:

$GENVALUE_{actual}$ is weighted average of the actual prevailing market price for generation as established in each tariff; and

$GENVALUE_{base}$ is the estimated weighted average market price of generation used to in establishing stranded costs and the related base CTC, embedded in the tariff for each class of service.

CTC_{base} is the weighted average CTC based upon projected market prices and value of generation and included in the tariff for each class of service.

$SALES_{projected}$ is the number of kWh used to determine the amortization schedule as listed in the table above.

E_{amort} is the adjustment that is made to the amortization schedule for generation related CTC to reflect the change in market conditions. This changes the total dollars which need to be collected through this portion of the CTC over the transition period.

Weighting is based upon projected kWh sales for each class of service.

After the amortization schedule has been adjusted for the prevailing market price for the period, the second step is to adjust the generation related CTC for actual level of collection according to the following formula.

$Gen_{act} - Gen_{amort\ adj} = E_{gen}$

where:

Gen_{act} is the actual amount collected from all classes of customers during a year for generation related competitive transition charges;

$Gen_{amort\ adj}$ is the amortization schedule adjusted for the change in the market value of generation for the same year for generation related competitive transition charges as shown in the schedule and as adjusted; and

E_{gen} is the over or under collections associated with generation related stranded costs based upon the difference between the amortization schedule and actual collections.

This process shall be repeated annually throughout the amortization period until the total amount for non-generation related stranded costs, as shown in the table above, is collected.

NEV STATEMENT NO. 1A

8/28/97

DIRECT TESTIMONY OF DAVID MAGNUS BOONIN
ADDITIONS AND CORRECTIONS TO NEV STATEMENT #1
DOCKET NO. R-00973954
AUGUST 28, 1997

Q. Mr. Boonin, do you have any additions or corrections to your pre-filed testimony, NEV-1?

A. Yes.

Q. Please state those changes.

A. At page 1, starting at line 13, I stated some of NEV's attributes. Since that filing was made NEV has received its license in Rhode Island, and is currently serving retail customers in that state. We are also now NEEPOOL members. NEV has recently submitted its license application with this Commission and has applied for associate membership with MAAC.

At page 5, line 8, I provide a partial listing of the items that must be considered when converting wholesale prices into the retail prices. At this time, I would like to expand that list to include administrative and general costs.

At page 8, line 25 the words "to the ISO" should be deleted.

At page 10, line 7 the word "desegregated" should be "disaggregated."

At page 10, line 8 the citation should read 2804(4)(II).

At page 11, line 11 the number 1.2 cents should be 1.7 cents.

At page 12, line 13 the word "adjusted" should be "reconciled" for clarity.

At page 14, line13 strike the phrase "PP&L acknowledges that."

At page 14, line 19 change the word "reconciling" to "adjusting for."

At page 14, line 28 change the word "A" to "As."

NEV STATEMENT NO. 2

8/28/97
1103

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application of Pennsylvania Power & Light Company For Approval of Its Restructuring Plan Under Section 2806 of the Public Utility Code	:	Docket No. R-00973954

DIRECT TESTIMONY
OF
NANCY I. DAY

Regarding Billing

Ql Please state your name and business address.

Al My name is Nancy I. Day and my business address is as follows:

New Energy Ventures, Inc.
1000 Wilshire Boulevard, Suite 500
Los Angeles, CA 90017.

Q2 By whom are your employed and in what capacity?

A2 I am employed by New Energy Ventures, Inc. My job title is Vice President, Customer Services. I am responsible for defining the critical elements necessary to delivery competitive services to energy customers. In addition I am responsible for the legislative and regulatory advocacy of policies and programs essential to build viable competitive energy markets. My resume is attached as Exhibit NEV/NID #1.

Q3 Please describe your background and experience in the energy services industry.

A3 From 1968 to 1995 I was employed by Southern California Gas Company, the nation's largest natural gas distribution utility. From 1990-94 I served as Vice President of Regulatory Affairs. In that capacity I was the senior officer responsible for developing and executing regulatory strategies. I directed a staff of 30 professionals responsible for obtaining the required regulatory authorizations needed to run the business. I led the company's regulatory initiatives related to the transition to competitive choice for the provision of natural gas.

Q4 What is the nature of your testimony in this proceeding?

A4 My testimony focuses on the role unbundling of distribution services plays in the formation of competitive energy markets. I will address the essential components of distribution service unbundling. Finally, I will discuss my experience in the deregulation of California's natural gas and electric services industries to the extent they pertain to the issue of service unbundling.

Q5 Why is distribution service unbundling an essential element of the restructured energy services market?

A5 The simple answer is profitability. Without the unbundling and competitive provision of distribution services new market entrants will eventually be starved out of the market. This will be the inevitable result when the margins on the sale of electricity are too small to support the new market entrant's service delivery overheads. In contrast, the utility service providers' costs for provision of these overheads are imbedded in the utility's distribution revenue requirement and the utility does not have to compete for the delivery of those services. This creates an improper and unfair advantage for the utility and if corrective action is not taken will result in the demise of customers' competitive alternatives.

Over time, the primary benefits from electric industry restructuring will come, not from commodity cost savings, but from changes at the customer's premises. The provision of these value added services is key to establishing sustainable business relationships with customers. Moreover, the types of services customers want and are willing to pay for are highly competitive, not monopoly services.

For example, from a wide array of competitive options customers want to select those options whose value equals or exceeds their cost. If the utilities package of services do not meet the customers needs yet the costs remain bundled the customer must pay twice, once to the utility for valueless services and once to the energy service provider for the customized package of customer-selected services.

A simple example illustrates this point. Customer "Big" has many facilities located throughout the State. Historically this customer was served by 3 different utilities all of whom billed for each meter served. Each utilities' billing format and rate characteristics were different. Customer "Big" employed a small staff to aggregate the utility charges by business unit and review them for accuracy. As part of his new bundle of energy services Customer "Big" wants an aggregated electricity bill, including both utility and energy service charges, subtotaled by business unit and provided on-line through the internet. Why should this customer have to pay for the utilities to continue to send him useless information?

Q6 What services and costs should be unbundled?

A6 My recommendations are based on the cost and service format applied to California utilities and I recommend the Pennsylvania Commission evaluate these recommendations in the context of Pennsylvania's facts.

The cost elements that represent a minimum level of unbundling are:

1. Meters and meter reading
2. Billing and collections (including data processing costs)
3. Customer Service
4. Commodity Procurement, scheduling, balancing, risk management and sales.
5. Uncollectible Expense
6. Working Cash Allowance

Q7 What did the California Public Utilities Commission decide with respect to unbundling distribution services?

A7 In D. 97-05-037 the California Public Utilities Commission ordered the following:

<u>Billing</u>

1. Customers may choose from three billing options as follows: utility and the new Energy Service Provider (ESP) provide separate bills, the utility consolidates bills for itself and the ESP, or the ESP consolidates bills for itself and the utility.

2. ESPs who provide consolidated billing for the utility are responsible for payment of the billed amounts to the utility regardless of their ability to collect from their customers.

3. Utilities may impose reasonable creditworthiness requirements on ESPs who provide consolidated billing. These requirements are to be the same as those required of a similarly sized and situated customer.

4. ESPs who provide consolidated billing must describe the utilities' charges on their bills in a manner consistent with the bill reporting standards the CPUC sets for the utilities.

<u>Meters and Meter Reading</u>

1. Utilities who wish to employ Automated Meter Reading (AMR) (or any other type of advanced metering system) technology throughout their service territories may do so subject to the following conditions:

- utility customers will have the choice of deciding whether they want to use the real-time metering capability offered by the technology

- only customers electing to use the real-time pricing capability of AMR will be required to pay for the costs of that technology

- utility shareholders will be at risk for the full recovery of the technology's costs

- at the same time, the utility installing AMR would not be required to lower its revenue requirement associated with metering as a results of cost savings achieved from adopting the technology

- balances risk and reward between ratepayers and shareholders

- a utility deciding to adopt AMR would provide the Commission with a deployment plan showing how the technology would be geographically deployed and on what timetable.

2. ESPs may install their own meters and must agree to share the metered information with the utility. The ESP and the utility will enter into a service agreement specifying the nature of the information to be collected, the means for sharing data, and a reasonable approach for ensuring that the metering equipment is installed, calibrated and maintained properly. The Commission will establish minimum standards governing open architecture for meters and communication.

   - large customers may use ESP meters beginning 1-1-98
   - small customers (less than 20 kilowatts) may use ESP meters beginning 1-1-99.

The Commission delayed installation of ESP meters for small customers by one year to "encourage a more studied movement through the various steps that must precede such a new commercial offering." (D. 97-05-039, pg. 17.)

Cost Separation

The Commission concluded that customers should not pay for costs that are not incurred and directed that utilities separately identify the net cost savings resulting from a customer's election to receive certain revenue cycle services from another service provider and to reduce distribution charges where appropriate.

Other Services

In addition to billing, metering and meter reading, the Commission found there are other costs related to customer service inquiries and uncollectibles that are "logically related to revenue cycle services." (D. 9705-039, pg. 18.) The Commission directed the utilities to identify the net customer service inquiry savings to be used to reduce customer charges in those situations where an energy supplier chooses to handle customer service inquiries. In response to the concerns expressed by one party, the Commission directed all parties to evaluate whether a universal uncollectibles pool should be established to motivate ESPs to serve customers who pose a higher credit risk.

Q8 The issue of distribution service unbundling was hotly contested in California. Why do you think the California Public Utilities Commission ordered unbundling?

A8 *In the California Commission's decision on unbundling* (D. 97-05-039) Commissioner Jesse J. Knight, Jr. wrote as follows:

"Unbundling bottleneck facilities has played a key component in regulation of the telecommunications industry and was an important part of the Commission's efforts to ensure that full and fair markets properly develop. Access to bottleneck facilities and the unbundling of potentially competitive services allows greater innovation in services, a more customer focused marketplace and an important check on the ability of the dominant provider to leverage market power into adjacent markets. This decision takes this important lesson and applies it to the *revenue cycle services of the electric industry.*"

Based on my active involvement in this proceeding and knowledge of the natural gas market in California I believe the Commission recognized that without revenue cycle service unbundling the competitive market in California would not flourish.

In 1991 when the California Commission opened the natural gas market to competitive choice they failed to unbundle services for residential and commercial customers (so-called Core Customers). As a result, the core natural *gas aggregation program never achieved significant market penetration and over* the years participation of marketers has declined from a high of 12 to 3 or 4 remaining today. Once the margins on natural gas purchases from marketers fell to +/-5%, the marketers' profit margins fell to unacceptably low levels.

Although natural gas marketers and aggregators were allowed to furnish the customer a consolidated bill, the customer received no credit for this cost from the utility. Moreover, the utility maintained control of the meter and the natural gas ESP had to delay his billing until he received the data from the utility. Utilities refused to provide the data to the customer in computer readable form and the ESP had to re-data enter the information to produce customers' bills. All of these hurdles resulted in additional costs for providing the services with no offsetting credits.

Q9 Does this conclude your testimony?

A9 Yes.

NANCY I. DAY

CAREER SUMMARY

Senior executive with extensive experience managing large line and staff organizations through profound business, regulatory and market changes. Managed regional utility operations and facilities with a focus on improving cost effectiveness and customer service. Led regulatory initiatives during a period of deregulation. Built coalitions and successfully developed consensus solutions to business and regulatory issues. Results-oriented, team-based leader with expertise in the following:

Regulatory Affairs	Governmental Affairs	Administrative Law
Facilities Management	Customer Service	Materials Management
Purchasing	Risk Management	Labor/Management Relations

ACCOMPLISHMENTS

New Energy Ventures, Inc., Pasadena, CA **1995-Present**

The nation's first Energy Agent, representing buyers in competitive electricity and natural gas markets.

Vice President -Customer Services (1995-Present)

Develop competitively bid portfolios of electricity and natural gas for NEV clients, direct the provision of an array of customer services including portfolio management, billing, management reports, regulatory analysis and advocacy.

Southern California Gas Company, Los Angeles, CA **1968-1995**

The nation's largest natural gas distribution company serving almost 5 million customers. Annual revenues of $3 billion.

Vice President, Regulatory Affairs (1990-1995)

Senior officer responsible for developing and executing regulatory strategies, directing regulatory proceedings and maintaining effective agency contacts and relationships. Managed the staff of 30 professionals responsible for obtaining required regulatory authorizations from the California Public Utilities Commission (CPUC), the California Energy Commission (CEC) and the Federal Energy Regulatory Commission. Testified before the California Legislature and presented oral arguments before the CPUC and the CEC.

- Led the regulatory initiatives that resulted in the landmark CPUC cost allocation decision to eliminate decades of cross-subsidies between customer classes.
- Directed the company's response to a CPUC-ordered management audit. This comprehensive audit examined every aspect of company operations over a 5-year period and resulted in no adverse findings.
- Implemented aggressive settlement strategies that successfully reduced litigation costs, regulatory delays and obtained the desired business results.
- Reduced the department's operating budget by 35% over 4 years.

Division Manager (1988-1990)
Senior operations manager responsible for the provision of natural gas and related services to 570,000 customers in the South Coastal Division. Managed over 700 employees and $60+ million budget related to the following: installation and maintenance of distribution pipelines and associated metering facilities, meter reading, telephone call center, bill reconciliation, collection, in-home appliance maintenance and repair, and public/government affairs.

- Refocused employee attention away from internal company processes to delivery of customer satisfaction. Customer complaints reduced by 38%.
- Dramatically improved labor/management relations and employee morale. Reduced grievances by 60% and improved employee safety by 22%.
- Instituted the first 12-hour telephone call center operation to improve customer service.
- Merged two divisions into one and consolidated the operation in a new headquarters.
- Revamped market research to obtain better information from our customers regarding customer satisfaction.

Manager of Material Services (1986-1988)
Managed the provision of centralized contracting ($150 million), purchasing ($120 million), warehousing, material distribution and inventory control services. Established functional policy for decentralized purchasing, contracting, and material management. Also managed the specialized fabrication and repair shops and the investment recovery operation.

- Lowered material delivery costs by 12%.
- Transformed a salvage sales operation into a profitable investment recovery operation and recycling program. Generated $1.5 million additional revenue per year.
- Redesigned the material distribution system to eliminate 60 local storerooms.

Manager of Risk Management and Claims (1985-1986)
Managed the placement of insurance, covering all aspects of the company's operations and assets, and the negotiation, settlement and litigation of claims against the company for property damage and personal injury.

- Completed the first comprehensive review of company loss control programs and recommended the strategy for increasing employee and public safety while reducing costs by as much as 30%.
- Instituted an aggressive contact program to achieve timely and low cost resolution of claims against the company.

Manager of Headquarters Services (1983-1985)
Managed the operation and maintenance of over 1 million square feet of office space in 5 different locations. Responsibilities included the following building occupant services: communications, reprographics, janitorial, mail and messenger, automotive maintenance, craft shops, archives, cafeterias, and travel.

- Created an in-house travel agency to earn commissions on all travel services. Offset costs by $100,000.
- Instituted a second shift in the reprographics operations to improve cost efficiency. Productivity increased by 26%.
- Instituted a cost planning and control system.

EDUCATION & PROFESSIONAL ACTIVITIES

Harvard University, Graduate School of Business Administration -
Advanced Management Program
University of Redlands - B.S. Business Administration
University of Southern California - Certificate of Management Effectiveness
Chairperson, Southern California Regional Purchasing Council