Public Service
Electric and Gas
Company

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March 17, 1999

In the Matters of
Public Service Electric and Gas Company
Restructuring, Stranded Costs, and Unbundling

BPU Docket Nos.
EO97070463, EO97070462, EO97070461

Mark Musser, Secretary
Board of Public Utilities
Two Gateway Center
Newark, New Jersey 07102

Dear Secretary Musser:

On behalf of the undersigned parties, enclosed is a Stipulation encompassing a resolution of the issues in the stranded cost and rate unbundling proceedings and all of the non-generic restructuring proceeding issues included by the Board in the settlement process. The undersigned parties, after extensive litigation and prolonged negotiations, have arrived at this Stipulation of the proceedings in a manner that resolves the following:

- Rate Reductions - PSE&G customers will receive four rate reductions over a three-year time period beginning with a 5% rate reduction on August 1, 1999 rising to 13.9 percent on August 1, 2002.

- Shopping Credits – One of the largest across-the-board restructuring rate reductions in the country is matched with the largest consumer shopping credit of any restructuring proceeding in the Country averaging in excess of five cents.

- Transition Period – Achieves full competition in only four years with Basic Generation Service supplied on the basis of a competitive bid in year four.

- PSE&G will transfer its Generation Assets and Liabilities to an unregulated company – This transfer, coupled with a Code of Conduct for Generation, is intended to establish a level competitive playing field for generation.

- Assurance of Capacity Availability within PJM – The transferred generating capacity will be maintained as a capacity resource within the PJM system for the four year transition period.

The undersigned parties have arrived at this Stipulation after having considered the positions of all of the parties as they were reflected on the record at the Office of Administrative Law and at the Board of Public Utilities in the above-referenced proceedings.

The parties, after considering the positions in the record and the directive for rate reductions in the New Jersey Electric Discount and Energy Competition Act, propose through this Stipulation that the rates for all customers be reduced by 5% on August 1, 1999. This rate reduction for customers will be approximately $200 million annually or $800 million over the transition period.

The parties have further agreed upon an additional estimated 2% rate reduction for all the Company's customers. This estimated 2% rate reduction is related to the cost savings resulting from the securitization process and is projected to become effective on or about January 1, 2000. The reduction will result in an additional reduction in customers' rates of $85 million annually or approximately $300 million during the transition period.

The undersigned parties have agreed that on August 1, 2001 rates will again be reduced for all customers so that the aggregate reductions will be 8¼%. At this point, annual discounts will total almost $350 million annually.

The final rate reduction, which will take place on August 1, 2002 pursuant to this Stipulation, will average 13.9%. This will result in a reduction of revenues of almost $600 million on an annual basis. The cumulative revenue savings to customers over the transition period will total approximately $1.5 billion.

The parties to the Stipulation, giving consideration to the positions regarding shopping credits in the record, have agreed to a level of shopping credits for the four-year transition period which is higher than that provided by any utility or required by any state in the Country. The shopping credit levels agreed to in the Stipulation, will provide all classes of customers, residential, commercial and industrial, as well as marketers, with an opportunity to develop and engage in a competitive retail electric marketplace.

Furthermore, the parties have agreed that the recovery of eligible stranded costs are \$3.3 billion, which is approximately \$600 million less than the Company's original request for recovery of \$3.9 billion. The parties have further agreed that the Company can only recover \$3.075 billion of stranded costs, which results in the Company's foregoing the recovery of an additional \$225 million of eligible stranded costs. Therefore, through this Stipulation, the parties have agreed that, based upon the record evidence, the Company will have the opportunity to recover a level of stranded costs that is substantially less than its original request in the proceeding.

The parties have also agreed that pursuant to the Act, the Company should be authorized to securitize approximately \$2.475 billion of its stranded costs agreed to in the Stipulation.

The undersigned parties, in order to promote the development of a competitive generation marketplace, have proposed that the Company will transfer all of its generating assets and liabilities out of the utility and into an unregulated company. This company will pay the utility full market value based upon the stranded asset values agreed to in the Stipulation. Additionally, this separation of generation from the utility will establish a framework for ensuring a level playing field for all other generators who will be offering generation services in New Jersey or within PJM. The Company has agreed that the unregulated generation company will, during the transition period, offer any excess capacity, after it has first provided reliable capacity services to the utility and its customers to other potential suppliers within the PJM region. By this feature of the Stipulation, reliable service will be assured to those customers who stay with the utility and capacity will be first provided to potential purchasers within PJM. This agreement will assure a reliable supply of economic capacity for potential purchases within PJM and should assist in the development of a competitive marketplace to the benefit of New Jersey's citizens.

In addition to Public Service Electric and Gas, the undersigned parties that have executed the Stipulation represent a wide range of diverse interests, all of who have been actively involved in these proceedings, as follows:

Natural Resource Defense Council (NRDC)

A national environmental organization that was active in the proceeding representing positions and interests concerned with assuring a clean environment.

New Jersey Commercial Users (NJCU)

A diverse group comprised of the New Jersey Food Council (NJFC) and the New Jersey Retail Merchants Association (NJRMA). The NJFC is the business trade association for the food distribution industry in New Jersey whose retail members represent over 1,500 New Jersey supermarkets and convenience stores along with their suppliers, many of which have locations in the service territory of PSE&G. The NJRMA represents over 1,400 companies conducting retail business in over 2,000 locations in New Jersey and within the service territory of PSE&G.

International Brotherhood of Electrical Workers 94 (IBEW94)

This party is the collective bargaining representative of approximately 4,000 employees of Public Service Electric and Gas Company (PSE&G), many of which are electric customers of the Company. These men and women operate the nuclear and fossil generation stations, construct and maintain both the high voltage transmission and area distribution electric lines and transformers read and service all aspects of metering staff the research laboratory.

New Jersey Transit Corporation

This party represents the largest single mass transit customer in the State of New Jersey.

Enron Capital and Trade Resources

A large wholesale and retail marketer of natural gas and electric power actively involved in all aspects of these proceedings.

Tosco

A customer which is one of New Jersey's largest companies engaged in the refining of petroleum products, who has been actively involved in these proceedings.

Independent Energy Producers of New Jersey (IEPNJ)

This party represents the interests of New Jersey's non-utility generators. They have been actively involved in these proceedings.

The undersigned parties request that the Board approve this Stipulation at its earliest opportunity. The Board's approval of this Stipulation will insure rate reductions for all customers, full retail access to competition as of August 1, 1999, unprecedented shopping credit levels and assured reliability for electric customers.

Very truly yours,

Francis E. Delany Jr.

Steven Montovano for Enron Capital
And Trade Resources

Francis E. Delany, Jr. for
Public Service Electric and Gas Company

Ashok Gupta for
Natural Resource Defense Council

Charles D. Wolfe, President for
International Brotherhood of Electrical
Workers, Local 94

William Harla, Esq. for
Independent Energy Producers of NJ

Ransome E. Owen for
New Jersey Transit Corporation

Michael J. Mehr, Esq. for
Tosco/Bayway

James E. McGuire, Esq. for
New Jersey Commercial Users

C Herbert H. Tate, President
Carmen J. Armenti, Commissioner
Service List

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STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Energy Master Plan Phase II Proceeding to Investigate the Future of the Electric Power Industry	Unbundling BPU Docket No. EO97070461 OAL Docket No. PUC-7348-97N Stranded Costs BPU Docket No. EO97070462 OAL Docket No. PUC-7347-97N Restructuring BPU Docket No. EO97070463

Public Service Electric and Gas Company STIPULATION

On January 16, 1997, the Board of Public Utilities (Board) issued an Order releasing "Restructuring the Electric Power Industry in New Jersey: Phase II Proceeding Proposed Findings and Recommendations Report" (Draft Report)

The Board held public meetings to receive comments on the recommendations contained in the Draft Report at the Board's Newark offices, at Camden County College in Blackwood, New Jersey, and at the Board's Trenton, New Jersey Hearing Room on February 4, 1997, February 5, 1997 and February 11, 1997, respectively.

On April 30, 1997, the Board released the Final Report entitled, Restructuring the Electric Power Industry in New Jersey: Findings and Recommendations (Green Book).

On February 9, 1999, the New Jersey Electric Discount and Energy Competition Act, Chapter 23 of the Laws of 1999 (Act), was enacted. It provides *inter* *alia* that all New Jersey retail electric customers are entitled to reduced electric rates and shall have the opportunity to exercise choice as to their electric supplier commencing August 1, 1999.

The undersigned parties rely upon the procedural history provided by ALJ Louis G. McAfoos in his Initial Decision of August 14, 1998 and on the procedural history provided by the parties in their briefs in the above-referenced proceedings.

On February 11, 1999 the Board, at an Open Public Meeting established a target date of March 3, 1999 for receipt of any stipulations between the parties in the proceedings and indicated it was targeting a decision in the proceeding for March 31, 1999. Subsequently, the parties convened on numerous occasions in an effort to resolve issues in these proceedings.

During the course of these conferences, the undersigned parties have collaboratively resolved the following issues in the above-referenced proceedings. As a result, it is hereby agreed among the undersigned that the following encompasses a resolution of all the issues in the above-referenced stranded cost and rate unbundling proceeding and all of the non-generic issues in the restructuring proceeding which the Board included in the settlement process:

RATE REDUCTIONS, TRANSITION PERIOD AND UNBUNDLED RATES

1) The parties agree that electric rate reductions shall be implemented as follows to comply with the provisions of Section 4(d) of the Act:

a) A 5% rate reduction from rates in effect as of the date of this Stipulation (hereinafter "current rates") for service rendered on and after August 1, 1999. This reduction includes a 1% reduction relating to the savings from securitization.

b) An estimated additional rate reduction of 2% of current rates targeted for service rendered on or after January 1, 2000 subject to the receipt prior to such date of a Bondable Transition Cost Rate Order establishing a securitization bond charge and providing for the securitization of $2.475 billion of generation-related stranded costs and the recovery of related taxes, costs of issuance, and transaction costs including costs of refinancing or retirement of debt or equity as provided in paragraph 11 (together "Bondable Stranded Costs") and the sale of the securitization bonds. The date of the reduction will be the same date as the securitization transition charge is established. The rate reduction provided to customers will reflect the actual savings from the issuance of the securitized bonds as computed under the methodology set out in Attachment 1, less the 1% savings included within the initial 5% rate reduction set forth in paragraph 1(a). This rate reduction and all subsequent rate reductions are contingent upon the implementation of the securitization transition charge.

c) A further rate reduction for service rendered on or after August 1, 2001 to bring the total rate reduction to 8.25% from current rates.

d) A final rate reduction for service rendered on and after August 1, 2002, in an amount that, when considered with the above reductions, will result in a rate reduction by customer class of 10% relative to rates in effect as of April 30, 1997.

e) All rate reductions will be applied to each customer's bill to reflect the above agreed upon reductions, as set forth on Attachment 2, page 2 of 19.

f) The rate reduction described in paragraph 1(d) shall be sustained until July 31, 2003.

2) The parties agree that there shall be a four-year transition period commencing on August 1, 1999 and terminating on July 31, 2003 (Transition Period).

3) The unbundled rates to be effective for each rate class in Public Service's Tariff for Electric Service have been developed using the Company's 1995 Cost of Service Study will be using the parameters defined in Attachment 2, including the unbundled rates and rate components. Each customer's bill shall indicate the

dollar amount of the difference between what the customer's total charges would have been without the reduction and the total charges in that bill pursuant to Section 4(b) of the Act.

DEPRECIATION

4) The parties agree that an excess electric distribution reserve in the amount of $568.7 million is to be amortized over three years and seven months beginning on January 1, 2000 and ending July 31, 2003. Amortization amounts will be $125 million in the year 2000, $125 million in the year 2001, $135 million in the year 2002, and $183.7 million in the year 2003.

SOCIETAL BENEFITS CHARGE CLAUSE (SBC)

5) The parties agree that consistent with Section 12 of the Act, Public Service will establish a Societal Benefits Charge Clause (SBC). The SBC will include costs related to: 1) Social Programs (including the Universal Service Fund); 2) Nuclear Plant Decommissioning costs; 3) Demand Side Management Program costs; 4) Manufactured Gas Plant Remediation costs; and 5) Consumer Education Costs.

6) The SBC will be set at the level of costs for the above items included in rates as of February 9, 1999, the effective date of the Act, and as more explicitly defined in Attachment 2. This SBC level will remain constant through the Transition Period.

Actual costs incurred by the Company for each of the cost components enumerated in paragraph 5 will be subject to deferred accounting. Interest at a seven-year single A debt rate (Interest Rate) will be accrued on any under- or over-recovered balances. At the completion of the Transition Period, the SBC will be reset and then reset annually upon Board approval to amortize any over- or under-collected balances.

7) The parties agree that the DSM generation-related lost revenue created subsequent to August 1, 1999 will no longer be reflected in the calculation of costs eligible for Demand Side Management Program cost recovery and deferral as described in Attachment 2.

NON-UTILITY GENERATION MARKET TRANSITION CHARGE (NTC)

8) Consistent with Section 13 of the Act, the parties agree that the Company's unbundled electric tariffs and distribution service rates will include a NTC to recover the above-market stranded costs of Public Service's existing non-utility generation contracts. These contracts will continue to remain the obligation of Public Service Electric and Gas Company during the life of the contracts. The Company will sell the energy and capacity from these contracts at the PJM Interchange Hourly Locational Marginal price and at wholesale within the PJM region, respectively.

9) The parties agree that the initial level of the NTC will be set based on the above-market non-utility generation (NUG) costs for 1999 of $183 million (Exhibit PS-20, Schedule CJL-F3) and as more explicitly defined in Attachment 2. This NTC level will remain constant for a period of four years from August 1, 1999. Actual annual payments made by the Company for NUG costs will be reduced by the value received from the sale of the energy and capacity associated with those contracts as described in paragraph 8. For the purpose of calculating the amount of stranded cost which Public Service is entitled to recover during the Transition Period, any increase or decrease in the above-market costs will be subject to deferred accounting and interest at the seven-year single A debt rate will be calculated on any under- or over-recovered balances. After the Transition Period, the NTC will be reset and then reset annually upon Board approval to amortize any over- or under-collected balances. Board approved buy-outs and buy-downs of NUG contracts will be reflected in this clause in a manner consistent with Section 13(l)(3) of the Act.

STRANDED COST QUANTIFICATION (GENERATION ASSETS)

10) The Company maintains that it has established, through its testimony and exhibits, a conservative valuation of the fair market value of its generation assets. This valuation, when compared with the net investment in its generation assets, results

in stranded costs of $3.873 billion (Exhibit PS-22, p.45). However, for purposes of this Stipulation, the Company and the signatories to this Stipulation agree that the Company is entitled to recover $3.30 billion of its generation-related stranded costs resulting from a market valuation of $0.046 billion and $1.722 billion for nuclear and fossil generating assets, respectively. The increase in the value of fossil generating assets represents a compromise between the positions of the Company and other parties. The Company and the signatories to this Stipulation agree to a total reduction of $225 million in the unsecuritized generation-related stranded costs including (1) to reflect the Company's estimated overrecovery in its Levelized Energy Adjustment Clause (LEAC) as of July 31, 1999 ($60 million after-tax) and (2) a reduction of $90 million of Salem stranded costs. As set forth in paragraphs 11 and 13, the Company will be provided with an opportunity to recover up to $3.075 billion of generation related stranded costs through securitization of $2.475 billion and an opportunity to recover up to $600 million of its unsecuritized generation related stranded costs on a present value basis.

SECURITIZATION

11) The parties agree that (i) Public Service, in order to comply with the requirements of Section 14 of the Act, will utilize the net proceeds of securitization, after payment of all related fees and expenses of issuance and sale, to refinance or retire

its debt and/or equity; (ii) that such refinancing and/or retirement of such debt may occur as a result of, among other things, mandatory and/or optional redemption, repurchase and/or tender by or on behalf of Public Service, which optional redemption, repurchase or tender may be at a premium; and (iii) that the Board should authorize Public Service to employ such methods as are reasonable and necessary to achieve the overall intent and purposes of the Act.

a) The parties agree that the Board issue a financing order to authorize Public Service to issue up to $2.6 billion of transition bonds representing $2.475 billion of generation-related stranded costs and an estimated $125 million of transaction costs including related fees and expenses of issuance, sale and to refinance or refund its debt and equity subject to approval of the Board. The parties other than the New Jersey Commercial Users also agree that all taxes related to securitization will be separately stated on the tariff and will be recovered through the Board-established transition bond charges. The New Jersey Commercial Users reserve the right to comment on this tax issue. The signatories to this Stipulation also agree not to oppose the issuance of such a financing order or the sale of such transition bonds in any judicial or regulatory forum.

12) The Company requests and the other parties do not object that the Board in connection with its review of Public Service's stranded cost filing and the record in the stranded cost proceeding should find pursuant to Section 14 of the Act that:

a) Public Service has taken reasonable measures to date on Mitigation of stranded costs (Exhibit PS-14) and the terms of this Stipulation including rate reductions, rate freezes, and other mitigation measures will create appropriate incentives in place to mitigate the total amount of its stranded costs;

b) Public Service will not be able to achieve the level of rate reduction deemed by the Board to be necessary and appropriate pursuant to the provisions of Sections 4 and 13 of the Act absent the issuance of transition bonds providing for the recovery of its Bondable Stranded Costs as set forth in paragraph 1(b); and

c) The issuance of such bonds will provide tangible and quantifiable benefits to ratepayers, including greater rate reductions than would have been achieved absent the issuance of such bonds and net present value savings over the term of the bonds (see Attachment 1).

UNSECURITIZED GENERATION STRANDED COST RECOVERY

13) Pursuant to paragraph 10, the parties agree that PSE&G should be provided with the opportunity to recover up to $600 million of its unsecuritized generation stranded costs on a net present value (8.42% discount rate) net of tax basis over the Transition Period. This recovery is to be accomplished via a 2 mill per kWh retail adder, an explicit Market Transition Charge (MTC), exclusive of the NTC, as discussed in Attachment 2, and the amount funded by the excess distribution depreciation reserve amortization. The parties further recognize that as Basic Generation Service (BGS) customers leave PSE&G for third-party suppliers, full recovery of these costs is not assured and represents a risk of undercollection to Public Service.

14) At the end of the Transition Period, the recovery of the $600 million will be reconciled to actual collections based on actual sales, the net present value (NPV) of recovery from both the MTC, exclusive of the NTC, and collections from a 2.0 mill per kWh retail adder for all customers retained on the BGS, and the depreciation amortization, and any payments to PSE&G resulting from BGS bidding in year four of the transition period pursuant to paragraph 17. In the event the Company fails to collect $600 million, it will be at risk for any such shortfall. In the event the Company collects over $600 million, it shall use any such

overrecovery to reduce the Company's SBC at the end of the Transition Period when the SBC is reset. The parties agree that the discount rate used in these present value calculations will be based on the same cost of capital/discount rate used to calculate securitization savings on Attachment 1.

BASIC GENERATION SERVICE/SHOPPING CREDIT

15) The parties agree that the Company's shopping credit shall equal its BGS rate, which shall be inclusive of an allowance for the cost of energy, capacity, transmission, ancillary services, losses, taxes and retail adder. The parties agree that the Company's BGS/shopping credit levels should be established and fixed for the duration of the transition period without adjustment or true up of any kind. Accordingly, the parties agree to the following:

	1999	2000	2001	2002	2003
RS	5.71	5.86	5.86	5.86	5.86
GLP	5.30	5.35	5.39	5.44	5.44
LPL-S	4.84	4.88	4.93	4.97	4.97
LPL-P	4.54	4.58	4.62	4.66	4.66
HTS-SubT	4.30	4.35	4.40	4.44	4.44
HTS-HV	4.12	4.16	4.21	4.25	4.25
Overall	4.95	5.03	5.06	5.10	5.10

The above rates are rate schedule averages, which will differ by blocks and time periods of each rate schedule as defined in Attachment 2. Other minor rate schedules (RHS, RLM, WH, WHS, HS, BPL and PSAL) will be calculated consistent with the above as presented in Attachment 2. Additional shopping-related savings, resulting from customers receiving electric generation service from a supplier at a price less than the above shopping credits, are above and beyond the rate reductions set forth in paragraph 1.

16) The parties agree that the above-referenced pre-established BGS rates meet the shopping credit definition in the Act and resolve the issue of BGS pricing and the shopping credit in a manner that accommodates the parties' concerns and satisfies the requirements of Sections 9(a) and 9(d) of the Act.

17) Basic Generation Service Obligation – Pursuant to Sections 9(a) and 9(b)(3) of the Act, the undersigned parties agree that the Company has a three-year obligation to provide BGS to those retail customers who choose to remain with the utility during the three-year period ending July 31, 2002. The parties agree that they support the bidding out of the BGS to be provided after July 31, 2002. The first year bid will be a pre-payment method based upon pre-established shopping credit for year 4. If the bid for generation results in a payment to PSE&G, it shall be considered as a part of the MTC. If the bid for generation requires a payment by PSE&G, such payment shall be subject to deferral and subsequent recovery at the Interest Rate. The undersigned parties agree that Public Service Enterprise Group Incorporated's (PSEG) non-regulated affiliate, pursuant to this Stipulation, will be authorized to

bid for such BGS to be provided after July 31, 2002 pursuant to terms that apply to other suppliers of electricity, subject to procedures to be determined by the Board.

18) The Company agrees that it will not promote its BGS as a competitive alternative.

GENERATION-RELATED ASSET TRANSFER FROM PSE&G TO AN AFFILIATED ENTITY

19) Pursuant to the provision of Section 7(d) of the Act, the parties will not object to the Board approving the transfer of the Company's electric generation-related assets and their operation, and all associated rights and liabilities into a separate corporate entity or entities (Genco) to be owned by Public Service Enterprise Group Incorporated and not by Public Service Electric and Gas Company. The specific generation facilities and assets which shall be transferred are identified on Attachment 3 (the "Generation Facilities"). Public Service represents that these facilities and assets constitute all of its specific assets related to electric generation.

20) The parties agree that the final and fixed transfer value pursuant to Sections 7(d) and 13(e) of the Act, for the Generation Facilities is $2.368 billion (Attachment 4), which is the fair market value of the assets transferred considering all revenues derived from the BGS contract described in paragraph 21 hereof. In addition, Public Service will transfer at book value at the time of transfer other generating-related assets including materials, supplies, and fuel. Such transfer prices will and

are intended to ensure that Public Service receives full and fair recompense for the Generation Facilities and related assets and that Public Service will not retain any liabilities associated with the transferred Generation Facilities and assures that customers' responsibility for stranded costs is established at the lowest reasonable level. No land held for future use (Account 105) will be transferred to Genco. All generation-related expenses will be borne by Genco. The Company shall have auditable accounting protocols in place no later than the effective date of the transfer to assure that all expenses and capital expenditures related to generation will be borne by Genco.

21) The BGS contract between Public Service and Genco will contain the following provisions:

a) To ensure the reliability of service to BGS and to remove the risk of price volatility to the regulated Company during the transition to a competitive market and to further ensure that Public Service can meet its contractual obligations to provide power under certain Off-Tariff Rate Agreements (listed in Attachment 5), the transfer to the Genco shall be accompanied by the Genco and Public Service's entering into a BGS contract whereby the Genco would provide full requirements service for energy, capacity, losses and ancillary services needed by the Company for BGS and for Off-Tariff

Rate Agreements for the period that the Company will be providing BGS under this Stipulation;

b) In exchange for ensuring the reliability of supply for Public Service's BGS, for removing the risk of price volatility from the regulated Company in providing such service and to further ensure that Public Service can meet its contractual obligations in its Off-Tariff Rate Agreements, the BGS contract shall provide that the consideration paid by Public Service for such full requirements service shall be (i) an amount computed on a monthly basis equal to the full amount charged for BGS to Public Service's retail electric customers as set forth in paragraph 15 (less any sales and use tax and transmission); (ii) an amount computed on a monthly basis equal to Public Service's retail delivery to Off-Tariff Rate Agreement customers, multiplied by the comparable BGS rate for such customers (less sales and use tax and transmission); and (iii) an additional charge for price stability services provided by the combustion turbine assets of Genco, payable based on the installed capacity of those assets. The additional charge, set forth in (iii) above, will be an amount computed on a monthly basis equal to the full actual amount collected pursuant to paragraph 13 excluding the 2 mill per kWh retail adder. Pursuant to Section 9(b)(3) of the Act, no net revenue from this contract may be used as a reduction of the MTC or distribution rates.

c) To further ensure the reliability of supply for Public Service's BGS and to remove the risk of price volatility from Public Service, the BGS contract shall also provide that Public Service shall transfer to the Genco the authority to act as its agent for the purpose of scheduling, electing and/or using all rights, including Fixed Transmission Rights, associated with transmission delivery of full requirements service for Public Service's BGS and Off-Tariff Rate Agreement customers. Genco will be responsible for costs related to BGS scheduling activities to the same degree it would be responsible for those costs for other load serving entities.

d) The BGS contract shall be filed with the Board. The parties reserve the right to comment to the Board on terms and conditions which are reflected in the BGS contract but which are not set forth herein.

22) To further ensure the reliability of the BGS after transfer of the Generation Facilities, Public Service shall continue to supply, on an as needed basis, dedicated intrastate natural gas transportation services for the Genco's own gas supplies from Public Service's city gate to the transferred generating facilities in accordance with the Stipulation approved in Docket No. ER94070293, OAL Docket No. PUC

7328-94 on May 5, 1995. Such dedicated intrastate natural gas transportation services shall continue to be supplied by Public Service to the Genco for the term of the BGS contract.

23) To ensure that the goals of reliable service and sustained rate reductions are achieved, the parties agree that the transferred Generation Facilities may only be sold or otherwise transferred by the Genco to any other party during the Transition Period if the other party agrees to take the Generation Facilities subject to entering into a comparable BGS contract with the same consideration including the right to recover the MTC allocated to such Generation Facilities. If a sale of some or any of the transferred Generating Facilities by Genco occurs within the Transition Period, any net after tax gains from such sale will be shared equally between shareholders and customers in a manner to be determined by the Board.

24) The Company requests, and the undersigned parties do not object that the Board find that qualifying the Generation Facilities being transferred, either separately or jointly, in accordance with Section 32(c) of the Public Utility Holding Company Act of 1935 as Exempt Wholesale Generators (EWG) will benefit consumers, is in the public interest, will not provide any unfair competitive advantage by virtue of the Genco's affiliation or association with the Company, and does not violate State law. As an EWG the Genco will not offer retail electric service.

25) The Company requests and the undersigned parties do not object to the Board finding that in accordance with Section 32(k) of the Public Utility Holding Company Act of 1935, the Board has sufficient regulatory authority, resources and access to books and records of Public Service Electric and Gas Company and any relevant associate, affiliate or subsidiary company, to ensure that the BGS contract will (a) benefit consumers; (b) not violate any State Law; (c) not provide the Genco any unfair competitive advantage by virtue of its affiliation or association with the Company; and (d) is in the public interest.

26) Public Service shall submit, within 60 days of the date of issuance of the Board's written Order approving this Stipulation, a tentative schedule for the receipt of authorization for the transfer from other agencies for the Generation Facilities described in Attachment 3. Within 60 days following approval, Public Service shall also file with the Board copies of any documents evidencing such transfer and assumption of liabilities in connection therewith. Upon the receipt of approval from other agencies, Public Service will provide a filing, which reflects the terms and the approvals received and accounting implemented.

27) The parties agree that in order to ensure that Public Service does not retain any risks or liabilities associated with the electric generating business after the Generating Facilities have been transferred, the Board should order that all

contracts (except for the NUG contracts) associated with the electric generating business, including, but not limited to, wholesale electric purchase and sales agreements, fuel contracts, real and personal property interests, and other contractual rights and liabilities, be transferred from Public Service to Genco simultaneous with the transfer of all generating assets, and to substitute the Genco for Public Service as the party(s) to any such contracts.

28) The parties recognize that various federal and state regulatory approvals, as well as third-party consents, will be necessary to complete the transfer of assets, rights and obligations contemplated by this Stipulation. The parties anticipate that such approvals and consents will result in a delay between the date that the Board issues an Order approving this Stipulation and the date that the Generation Facilities are actually transferred. To ensure that the intent of the parties is kept intact during this period of transfer and that Public Service is not unduly penalized while diligently complying with this Stipulation and supplying BGS at rates approved by the Board, the parties agree that in order to effectuate the purposes of this Act under Section 9(b)(3), any requirement under Section 7 of the Act which would require the payment of any percentage of net revenues for the sharing of common assets and personnel is inapplicable.

29) Generating capacity transferred to Genco will be maintained as a capacity resource within the PJM system for the Transition Period. During that period, Genco will be permitted to sell said capacity outside of the PJM system for periods of less than one year after it makes good faith efforts to sell the transferred capacity into the PJM system at market rates.

30) The parties other than Enron agree that in addition to any other Affiliate Standard of Conduct that might apply to Public Service, the following shall apply, until the expiration of the MTC as provided herein or until appropriate and applicable safeguards or Code of Conduct are adopted by the FERC, whichever occurs first, to transactions by Public Service in its role as supplier of BGS or by any related business segment of Public Service or related business segment of Public Service's holding company selling electric power at retail in New Jersey (PSEG Supplier), with PSEG's Genco.

> "Neither Public Service nor PSEG Supplier shall receive from Genco an unreasonable preference over a non-affiliated retail electric supplier (RES) that is not comparable to that afforded a non-affiliated RES in the purchase, sale, use or conveyance of goods and services. This provision shall not apply to the BGS Wholesale Supply Agreement entered into between Genco and Public Service and approved by the Board."

Relative to other electric power generators, Genco will receive no unreasonable benefit or unreasonable preference from its relationship with PSE&G.

30A) Enron contends that the Affiliate Standard of Conduct that should apply is as follows:

> "GENCo shall not offer power or other services to any of its affiliates which are not made generally available to non-affiliated companies, nor shall it offer such power or other services to affiliates at prices more favorable than those generally available in the competitive marketplace and/or to those offered to non-affiliated companies. This provision shall not apply to the BGS Wholesale Supply Agreement entered into between Genco and Public Service and approved by the Board."

Relative to other electric power generators, Genco will receive no unreasonable benefit or unreasonable preference from its relationship with PSE&G.

31) The Company requests and the other parties do not object that the Board should further find that the transfer of Generation Facilities and related rights and liabilities contemplated by this Stipulation is in the public interest and will not jeopardize the reliability of the electric power system. The parties also agree that such transfer will not adversely impact the ability of Public Service to meet its obligations to its employees with respect to pension benefits, as contemplated pursuant to *N.J.S.A.* 48:3-7.

32) The Company requests and the other parties do not object that the Board further should find that the requirements under *N.J.A.C.* 14:1-5.6 or any other Board Order or regulation in conjunction with Public Service's compliance with this

Stipulation are waived because of the extensive nature of the record regarding valuation of the assets being transferred and that no further authorizations by the Board are required to effectuate this Stipulation.

NUCLEAR DECOMMISSIONING TRUST FUNDS

33) Upon the transfer of the nuclear generation assets, neither Public Service Electric and Gas Company nor its retail customers shall be responsible to decommission its previously owned nuclear units, subject to the Nuclear Regulatory Commission (NRC) approval. That responsibility will pass to the Genco with the transfer of the nuclear generation and associated assets described in Attachment 3 and the Nuclear Decommissioning Trust Funds.

OTHER TARIFF CHANGES

34) On February 1, 1999, the Company filed its proposed Third-Party Supplier Master Service Agreement. At that time, the Company also filed associated electric tariff modifications annexed hereto as Attachment 6, which also reflected the recognition of a capacity market for generation. This Attachment was developed prior to the enactment of the Act and reflects a net back approach for capacity and energy. The parties agree that the proposed tariff modifications be approved subject to: (1) conformance with the balance of this Stipulation; (2) conformance

with the Act; (3) changes resulting from the resolution of restructuring issues; and, (4) changes as a result of the Third-Party Supplier Master Service Agreement resolution. These changes will be included in a completely new tariff which will be filed with the Board after approval of this Stipulation and resolution of other restructuring issues.

MARKET POWER/MONITORING

35) The parties agree with Staff's recommendation that the Board work cooperatively with the PJM-ISO to monitor actual market behavior in connection with the PJM-ISO's FERC ordered market monitoring plan (Exhibit S-8, Audit of PSE&G Restructuring Filing, p.7)

BILLING AND METERING PROCEEDING

36) The parties agree to work cooperatively to conclude the billing and metering proceeding in an expedited fashion, which proceeding the parties request that the Board conclude by May 1, 2000.

CONCLUSION

37) The undersigned agree that this Stipulation contains mutually balancing and interdependent provisions and is intended to be accepted and approved in its entirety and the parties agree to be bound by its terms. In the event any particular aspect of this Stipulation is not accepted and approved by the Board, this Stipulation shall be null and void and the parties shall be placed in the same position that they were in immediately prior to the execution of this Stipulation. The parties agree that nothing in this agreement shall prevent the parties from arguing a different policy or position before the Board in any other proceeding including issues related to competitive and Code of Conduct matters.

Public Service Electric and Gas Company

By Francis E. Delany Jr. 3/16/99
Francis E. Delany, Jr., Esq.

International Brotherhood of Electrical Workers Local 94

By Charles D Wolfe 3/15/99
Charles D. Wolfe, President

Enron

By 3/16/99
Steven Montovano
Enron Corporation

Natural Resource Defense Council

By Ashok Gupta 3/15/99
Ashok Gupta

New Jersey Transit Corporation

By Ransome Owan 3/17/99
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New Jersey Commercial Users

By James E McGuire 3/16/99
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Independent Energy Producers of NJ

By 3/16/99
William Harla, Esq.
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Tosco/Bayway

By Michael J Mehr 16 Mar 1999
Michael J. Mehr, Esq.
Waters, McPherson, McNeill

SCHDULE OF ESTIMATED SECURITIZATION PAYMENTS
15 Years 6.5% Interest
(thousand of $)

Investment Recovery	2,475,000
Issuance cost	25,000
Use of funds cost	100,000
Total Principal	2,600,000

Year	Payment including SUT	Principal	Interest 6.50%	State tax 9%	Fed tax 35%	SUT
2000	408,429	131,352	169,000	18,718	66,241	23,119
2001	408,429	136,402	160,462	19,486	68,960	23,119
2002	408,429	141,646	151,596	20,284	71,784	23,119
2003	408,429	147,092	142,389	21,113	74,716	23,119
2004	408,429	152,748	132,828	21,973	77,762	23,119
2005	408,429	158,620	122,899	22,867	80,924	23,119
2006	408,429	164,719	112,589	23,795	84,208	23,119
2007	408,429	171,052	101,882	24,759	87,618	23,119
2008	408,429	177,629	90,764	25,759	91,159	23,119
2009	408,429	184,458	79,218	26,798	94,836	23,119
2010	408,429	191,550	67,228	27,877	98,655	23,119
2011	408,429	198,914	54,778	28,998	102,621	23,119
2012	408,429	206,562	41,848	30,162	106,739	23,119
2013	408,429	214,504	28,422	31,370	111,015	23,119
2014	408,429	222,751	14,479	32,625	115,456	23,119
		2,600,000	1,470,382	376,585	1,332,692	346,780

SECURITIZATION SAVINGS

Year	Revenue Requirement incl'g SUT	Payment	Savings	PV Of Rate Savings
2000	546,161	408,429	137,732	127,036
2001	535,373	408,429	126,944	107,992
2002	524,694	408,429	116,264	91,226
2003	517,230	408,429	108,801	78,740
				404,994

123,421	3.0%
Level'd Amt-4 yrs.	Rev base $4.082

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

RATE DESIGN/RATE REDUCTION SPECIFICS

Unbundled rates will be developed for each rate schedule showing the following components:

Service Charge: No change from service charges, including sales tax, in effect on January 1, 1999.

Distribution Charge: Based on the unbundling analysis provided in Exhibit PS-55 of the rate unbundling proceeding. The 1995 cost of service study was rerun to remove those components of the proposed Societal Benefits Charge, including gross receipts and franchise tax, from the Distribution Delivery component. Unbundled cost components of Distribution Access, Distribution Delivery and Customer Services are then summed by rate schedule. To this subtotal, $80.46 million related to OPEB was added and $20 million related to a stipulated reduction in the distribution cost of capital to 9.5% was subtracted. The net of these two changes was allocated to the rate schedules based on the sum of Distribution Delivery and Distribution Access. Revenue requirements recovered through the Customer Service Charges were then removed from the balance of the distribution unbundled costs. This balance was then increased for the effects of the Corporate Business Tax related to distribution through application of the PSE&G "A" factor from the Energy Tax Reform proceedings. TEFA taxes in effect for 1999 were then added to the distribution unbundled rates. The rate design provided in subsequent pages will be modified in each year to reflect the year's TEFA tax rates for subsequent years when determined by the Board. Final rates include the appropriate sales tax.

Transmission Charge: The PJM OATT PSE&G rate for network integration transmission service charge (including Schedule 1 charges) was used as the basis for the retail Transmission Charge.

For rate schedules GLP, LPL, and HTS the monthly transmission charge is equal to the transmission rate divided by twelve times the customer's individual transmission obligation (in kilowatts), adjusted for losses and NJ Sales and Use Tax.

For residential rates and the balance of the rate schedules, the monthly transmission charge was converted to a per kWh charge. This is equal to the transmission rate, times the rate class's 1999 unrestricted coincident peak divided by 1999 kWh sales, adjusted for losses and for NJ Sales and Use Tax.

Capacity Charge: For rate schedules GLP, LPL and HTS, this charge is the annual generation capacity values from the stranded cost proceeding, divided by twelve, times the customer's PJM capacity obligation adjusted for voltage level losses and sales tax. For the balance of the rate schedules, the capacity charge will be included in the kWh charge for Basic Generation Service. It will be determined by utilizing the identical generation capacity value used above times the rate class's 1999 unrestricted coincident peak divided by 1999 kWh sales adjusted for losses and for NJ Sales and Use Tax.

Basic Generation Service (BGS) Charge: For rate schedules GLP, LPL and HTS, this charge, combined with the unbundled capacity charge and the transmission charge described above, comprise what is referred to as the "shopping credit" in the Act and in the body of the Stipulation. For the balance of the rate schedules, this BGS charge will include the capacity charge described above.

Securitization Transition (STC) Charge: An equal per kWh charge for all kWh, adjusted at least annually, including all applicable State and Federal taxes.

Societal Benefits Charge (SBC): A kWh charge as described in the body of the Stipulation. Details of the charge are set forth in pages 8 to 9 of this attachment.

DSM lost revenues are presently calculated as specified in the Company's DSM Resource Plans. This starts with total revenues by rate schedule, by time period, exclusive of sales tax. From this amount, TEFA taxes and variable production expenses are subtracted. The remainder is divided by that month's sales, by rate schedule time period, to derive that month's fixed costs. This fixed cost per kWh is then multiplied times the lost kWh by rate schedule time period for that month.

Effective August 1, 1999 lost revenues will be calculated by rate schedule time period to include only revenues from Distribution Charges and Transmission Charges, exclusive of Sales and TEFA taxes.

Non-Utility Generation Transition Charge (NTC): A kWh charge as described in the body of the Stipulation. Details of the charge are set forth in page 10 of this attachment.

Market Transition (MTC)Charge: These kW and kWh charges will be developed for each rate schedule for each year as the residual in the kW and kWh charges, starting with the rates in effect in each year without the rate reductions described below, less all of the charges described above. A net MTC will appear on the customer's bills as the sum of the unbundled MTC charges, the NTC charge, less the Restructuring Reduction.

Restructuring Reduction: This will appear on a customer's bill as a line item to meet the legislative requirement to show the effects of the legislation on a customer's bill. It will be calculated as a fixed percentage of the subtotal of the above charges, varying by rate class by year. For those customers who are purchasing their energy supply from a third party supplier, a subtotal will be calculated assuming the customer is taking basic generation service for the purpose of calculating the discount.

Other Rate Schedule Changes: Rate Schedule EHEP will be modified, similar to the changes proposed in the unbundling proceeding, to allow the existing customer contract to appropriately reference the restructured HTS tariff. Rate Schedule SL will be split into Rate Schedules BPL and PSAL as proposed by the Company in its July 1997 filing and which was unopposed by any party.

Tariff Format: Pages 4 of 40 and 5 of 40 show sample Commercial and Industrial and Residential unbundled tariff formats.

Bill Format: Page 6 of 40 shows a sample bill format for a Commercial and Industrial rate schedule. Residential rate schedule bills will be developed in a similar format. Page 7 of 40 shows the formulas used in the development of unbundled components after discount in the sample bill format.

Detailed Rate Design Components: Pages 11-15 of 40 show the 1999 Unbundled Rates Detail, including the rates which will appear on the rate schedule tariff sheets for August 1, 1999. These rates include the TEFA tax rates for 1999. Also shown are the shopping credit by block and time period and the overall average shopping credit by rate schedule.

Pages 16-40 of 40 provide the 2000-2003 Unbundled Rates Detail. The years 2000, 2001, and 2002a include 1999 rates and 1999 TEFA tax rates. The years 2002b and 2003 (10 percent rate reduction period) reflect 1998 rates and 1998 TEFA rates. All these years will be modified to reflect the TEFA tax rates for subsequent years when determined by the Board.

SAMPLE TARIFF FORMAT

Rate Schedule Comm. &Ind.

Service Charge :	$SC1	In each month	
Capacity Obligation:			
Basic Generation Service - Generation Capacity	$A	per KW of capacity obligation per month	
Transmission Capacity	$B	per KW of trans. capacity obligation per month	

	On-Peak	Intermediate	Off-Peak
Kilowatt Charge–Summer:			
Per kilowatt of monthly maximum demand			
Market Transition Charge	$C	$D	$E
Distribution Charge	$F	$G	$H
Total	$I	$J	$K
Kilowatt Charge–Winter:			
Per kilowatt of monthly maximum demand			
Market Transition Charge	$L	$M	$N
Distribution Charge	$O	$P	$Q
Total	$R	$S	$T
Kilowatthour Charge:			
Per kilowatthour			
Basic Generation Service	$U	$V	$W
Market Transition Charge	$X	$Y	$Z
Securitization Transition Charge	$AA	$AB	$AC
Distribution Charge	$AD	$AE	$AF
Adjustment Charges:			
Societal Benefits Charge	$SBC	$SBC	$SBC
Non-Utility Generation Transition Charge	$NTC	$NTC	$NTC
Total	$AG	$AH	$AI

Actual Tariff sheets will show rates both with and without Sales and Use Tax.

SAMPLE TARIFF FORMAT

Rate Schedule Residential

Service Charge:	$SC2	In each Month	
	First 600 kilowatthours used in each month	**In excess of 600 kilowatthours used in each of the months of Jun.-Sept.**	**In excess of 600 kilowatthours used in each of the months of Oct.-May.**
Kilowatthour Charges:			
per kilowatthour			
Basic Generation Service	$BA	$BB	$BC
Market Transition Charge	$BD	$BE	$BF
Securitization Transition Charge	$BG	$BH	$BI
Transmission Charge	$BJ	$BK	$BL
Distribution Charge	$BM	$BN	$BO
Adjustment Charges:			
Societal Benefits Charge	$SBC	$SBC	$SBC
Non-Utility Generation Transition Charge	$NTC	$NTC	$NTC
Total	$BP	$BQ	$BR

Actual Tariff sheets will show all rates both with and without Sales and Use Tax.

SAMPLE BILL FORMAT
Rate Schedule Comm. & Ind.

Rate Component	usage	Rate	$	Unbundled Components After Discount	$
Service Charge	xxxx	$SC1	xxxx	Customer	xxxx
Capacity Obligation- Generation	xxxx	$A	xxxx	Basic Generation Service (BGS) *	xxxx
Transmission	xxxx	$B	xxxx	Market Transition Charge (MTC)	xxxx
				Securitization Transition Charge (STC)	xxxx
KW On-Peak	xxxx	$I	xxxx		
KW Inter	xxxx	$J	xxxx		
KW Off-Peak	xxxx	$K	xxxx		
				Transmission *	xxxx
				Distribution	xxxx
KWhr On-Peak	xxxx	$AG	xxxx		
KWhr Inter	xxxx	$AH	xxxx		
KWhr Off-Peak	xxxx	$AI	xxxx	SBC	xxxx
Other charges (e.g. Area Devel. Svc.)	xxxx	$XXX	xxxx		
			----------		----------
Restructuring Rate Reduction			$ (x.xx)		
Subtotal			$ yy.yy	Total of Charges =	$yy.yy
***	***	***	***		
If you are supplied by a Third Party Supplier, you do not have to pay the items asterisked (*) above right					
			(x.xx)		
TPS Billing			q.qq		
Pay this amount			$zz.zz		

***This area varies depending on billing options and customer choice: customer stays with PSE&G, PSE&G bills for TPS, TPS bill separately.

SAMPLE BILL FORMAT
Rate Schedule Comm. & Ind.

Unbundled Components After Discount	Expanded Right Side $
Customer	Revenue resulting from $SC1
Basic Generation Service (BGS) *	Revenue resulting from $A+$U+$V+$W
Market Transition Charge (MTC)	Revenue resulting from $C+$D+$E+$X+$Y+$Z+$NTC less Restructuring Rate Discount
Securitization Transition Charge (STC)	Revenue resulting from $AA+$AB+$AC
Transmission *	Revenue resulting from $B
Distribution	Revenue resulting from $F+$G+$H+$AD+$AE+$AF
SBC	Revenue resulting from $SBC
Total of Charges =	$yy.yy

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J.No. 13 ELECTRIC

Original Sheet No.

SOCIETAL BENEFITS CHARGE

Average Cost per kilowatthour for:	Cost of Recovery (cents)
Social Programs	0.05432
Nuclear Decommissioning Funding Requirements	0.07739
Demand Side Management Programs	0.43402
Manufactured Gas Plant Remediation	0.00508
Consumer Education	0.00000
Universal Service Fund	0.00000
Sub-total Cost per kilowatthour	0.57081

Amount per kilowatthour of cost recovery after application of losses:

Secondary Service	(Loss Factor = 9.3704 %)	0.6298
LPL Primary	(Loss Factor = 4.9590 %)	0.6006
HTS Subtransmission	(Loss Factor = 3.5591 %)	0.5919
HTS High Voltage	(Loss Factor = 1.2054 %)	0.5778

Charges including New Jersey Sales and Use Tax (SUT)

Secondary Service	0.6676
LPL Primary	0.6366
HTS Subtransmission	0.6274
HTS High Voltage	0.6125

Date of Issue: Effective:

Issued by ______________________

80 Park Plaza, Newark, New Jersey 07101

Filed pursuant to Order of Board of Public Utilities, dated

in Docket No.

SOCIETAL BENEFITS CHARGE
(Continued)

Societal Benefits Charge
This mechanism is designed to insure recovery of costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Actual costs incurred by the Company for each of these cost components will be subject to deferred accounting. Interest at the seven-year debt rate for a single A rated utility will be accrued on any under- or over-recovered balances.

Social Programs
This factor shall recover costs associated with existing social programs. This includes but is not limited to uncollectible customers accounts.

Nuclear Decommissioning Funding Requirements
This factor shall recover costs associated with nuclear decommissioning funding requirements necessary to meet Federal or State requirements to decommission the nuclear units.

Demand Side Management Programs
This factor is a recovery mechanism which will operate in accordance with the Demand Side Management (DSM) conservation incentive regulations. The factor shall recover Core and Performance Program Costs and Performance Program Payments on a current basis, and shall also recover payments for Large-Scale Conservation Investments.

Core and Performance Program Costs of BPU-approved DSM programs consist of, but are not limited to, rebates, grants, payments to third parties for program implementation, direct marketing costs, DSM hardware, administration, measurement and evaluation of DSM programs, customer communication and education, market research, costs associated with developing, implementing and obtaining regulatory approval, costs of research and development activities associated with DSM, applicable Lost Revenues, and DSM advertising costs.

Performance Program Payments are based upon a standard price offer for general applications or for particular DSM measures, which establishes a per unit price for energy and capacity savings which Public Service will pay to third parties for DSM projects which meet viability, technological, measurement and verification criteria.

Large-Scale Conservation Investments are payments for measured and verified energy savings from contracts executed in response to PSE&G's Request for Proposals under the Stipulation of Settlement in Docket No. 8010-687B dated July 1, 1988.

Manufactured Gas Plant Remediation
This factor shall recover costs associated with addressing and resolving claims by and or requirements of governmental entities and private parties related to activities necessary to perform investigations and the remediation of environmental media.

Consumer Education
This factor shall recover restructuring costs such as educating residential, small business, and special needs consumers about the implications for consumers of the restructuring of the electric power industries. The consumer education program shall include, but need not be limited to, the dissemination of information to enable consumers to make informed choices among electricity services and suppliers, and the communication to consumers of consumer protection provisions .

Universal Service Fund
This factor shall recover costs associated with new or expanded social programs.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J.No. 13 ELECTRIC

Original Sheet No.

NON-UTILITY GENERATION TRANSITION CHARGE

			Cost of Recovery (cents)
Total Cost per kilowatthour			0.43540
Amount per kilowatthour of cost recovery after application of losses:			
Secondary Service	(Loss Factor =	9.3704 %)	0.4804
LPL Primary	(Loss Factor =	4.9590 %)	0.4581
HTS Subtransmission	(Loss Factor =	3.5591 %)	0.4515
HTS High Voltage	(Loss Factor =	1.2054 %)	0.4407

Charges including New Jersey Sales and Use Tax (SUT)

Secondary Service	0.5092
LPL Primary	0.4856
HTS Subtransmission	0.4786
HTS High Voltage	0.4671

Non-Utility Generation Transition Charge
This mechanism is designed to insure recovery of costs associated with activities that are required to be accomplished to achieve specific public policy determinations mandated by Government. Actual costs incurred by the Company for each of these cost components will be subject to deferred accounting. Interest at the seven-year debt rate for a single A rated utility will be accrued on any under- or over-recovered balances.

This factor shall recover above market costs associated with non-regulated generation costs which are related to existing (as of July 1, 1997) long-term contractual power purchase arrangements approved by the Board and/or established under requirements of the Public Utility Regulatory Policies Act of 1978.

Date of Issue: Effective:

Issued by ______________________________
80 Park Plaza, Newark, New Jersey 07101
Filed pursuant to Order of Board of Public Utilities, dated
in Docket No.

1999 Unbundled Rates
Detail

			bill det. 1999 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal (8=sum 3-7)	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
RS															
	Service Charge		20,231,858	2.41	0.00	0.00	2.41	0.00	0.00	2.41	0.00	0.00	0		
	Energy Charges														
		0-600	7,966,126	11.6394	1.1768	0.6679	3.2744	4.9927	0.0000	10.1118	1.5276	5.6606	450,931		
		Over 600 Sum	1,446,728	13.1022	1.1768	0.6679	3.6795	5.8875	0.0000	11.4117	1.6905	6.5554	94,839		
		Over 600 Win	1,134,116	11.0607	1.1768	0.6679	3.1008	4.3484	0.0000	9.2939	1.7668	5.0163	56,891		
	Totals		10,546,970									**5.71**	602,661		
RHS															
	Service Charge		202,344	2.41	0.00	0.00	2.41	0.00	0.00	2.41	0.00	0.00	0		
	Energy Charges														
		0-600	120,617	11.6394	1.1768	0.3460	4.0895	3.9530	0.0000	9.5653	2.0741	4.2990	5,185		
		Over 600 Sum	18,656	13.1022	1 1768	0 3460	4.6089	5.1495	0.0000	11 2812	1.8210	5.4955	1,025		
		Over 600 Win	115,381	8 0174	1 1768	0.3460	2.8285	3.5482	0.0000	7.8995	0.1179	3.8942	4,493		
		Common	0	13 1022	1 1768	0.3460	4.6089	5.1495	0.0000	11.2812	1.8210	5.4955	0		
	Totals		254,654									**4.20**	10,703		
RLM															
	Service Charge		59 630	12 12	0.00	0 00	12.12	0 00	0.00	12.12	0.00	0.00	0		
	Service Charge over 20,000		121,066	6 79	0.00	0 00	6.79	0 00	0.00	6.79	0.00	0.00	0		
	Service Charge Sp. Prv. (I)														
	Energy Charges														
	Summer	On	61,543	17 6369	1.1768	0.5547	3 7675	7 4115	0.0000	12.9105	4.7264	7.9662	4,903		
		Inter	11,539	16.1126	1 1768	0.5547	3.2418	6.3404	0.0000	11.3137	4.7989	6.8951	796		
		Off	55,132	6 3140	1.1768	0.5547	1.2092	3.7262	0.0000	6.6669	(0.3529)	4.2809	2,360		
	Winter	On	81,842	12 0486	1.1768	0 5547	2.6110	4 7211	0.0000	9.0636	2.9850	5.2758	4,318		
		Inter	16,740	12.2680	1 1768	0.5547	2.4708	4 3946	0.0000	8.5969	3.6711	4.9493	829		
		Off	87,422	6 3140	1 1768	0 5547	1.2092	3.4069	0.0000	6.3476	(0.0336)	3.9616	3,463		
	Totals		314,218									5.30	16,669		
WH															
	Energy Charge		11,362	10 1713	1.1768	0.0000	5.2921	2.4607	0.0000	8.9296	1.2417	2.4607	280		
	Totals		11,362									**2.46**	280		
WHS															
	Service Charge		1,270	2.82	0.00	0.00	2.82	0.00	0.00	2.82	0.00	0.00	0.000		
	Energy Charge		243	5.4289	1.1768	0.0000	1.5340	2.4631	0.0000	5.1739	0.2550	2.4631	5.985		
	Totals		243									**2.46**	5.985		

STC, preliminary values, adjusted at least annually.

1999 Unbundled Rate:
Detail

	bill det. 1999 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal (8=sum 3-7)	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
GLP													
Service Charge	2,825 642	4 04	0 00	0 00	4 04	0 00	0 00	4 04	0	0	0		
Service Charge- Night Use	1 356	367 08	0 00	0 00	367 08	0 00	0.00	367.08	0	0	0		
Capacity Obligation	25,428	0 0000	0 0000	0 0000	0 0000	2 9150	0 0000	2 9150	(2.9150)	2.9150	74,123		
Transmission Obligation	21,408	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1.5961	(1.5961)	1 5961	34,169		
Demand Charges		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0		
Summer 0-1	707	4 8866	0 0000	0 0000	3 0170	0 0000	0 0000	3.0170	1 8696	0.0000	0	1.9315	(0 0619)
over 1	10,737	9 5930	0 0000	0 0000	5 9158	0 0000	0.0000	5 9158	3.6772	0.0000	0	3.7946	(0.1174)
Winter 0-1	1,419	4 8866	0 0000	0 0000	3 0170	0.0000	0.0000	3 0170	1.8696	0.0000	0	1.9315	(0.0619)
over 1	18,956	8 4588	0 0000	0 0000	5 2059	0.0000	0.0000	5.2059	3.2529	0.0000	0	3.3468	(0.0939)
Energy Charges													
All Use-x night use	8,008,085	8 2050	1 1768	0.0000	0 3583	3.9525	0.0000	5.4876	2 7174	3.9525	316,520		2.7174
Night Use	60,685	7 0751	1 1768	0 0000	0.3583	3 9525	0.0000	5.4876	1.5875	3.9525	2,399		1.5875
Totals	8,068,770									5.30	427,211		
Monthly Minimum, MD													
Special Annual Minimum													
Special Provisions													
Standby	2 000	3 8600	0 0000	0 1800	2 8900	0 7800	0 0000	3 8500	0.0100	0.9600	2		
Area Dev Svc Cr Yrs 1-5	357	(2 8500)	0 0000	0 0000	(2 8500)	0 0000	0 0000	(2 8500)	0.0000	0.0000	0		
Area Dev. Svc. Cr Yrs 6&7													
Curt Elec Svc Cr													
Curt Elec Svc Peak Cr													
Police/Fire-Each													
Police/Fire-Minimum													
HS													
Energy Charges													
Summer	4,684	14 2258	1 1768	0.3788	5.7003	5 3637	0.0000	12.6196	1.6062	5.7425	269		
Winter	25,648	10.9897	1 1768	0.3788	4.3648	3.8348	0 0000	9.7552	1.2345	4.2136	1,081		
Totals	30,332									4.45	1,350		

1999 Unbundled Rate
Detail

		bill det. 1999 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal (8=sum 3-7)	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
LPL-Secondary														
Service Charge		77 386	368 64	0 00	0.00	368 64	0.00	0.00	368.64	0	0	0		
Capacity Obligation		26,556	0 0000	0 0000	0 0000	0 0000	2 9150	0.0000	2.9150	(2.9150)	2.9150	77,411		
Transmission Obligation		22,344	0 0000	0 0000	1 5961	0 0000	0 0000	0.0000	1.5961	(1 5961)	1.5961	35,663		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0.0000	0.0000	0		
Summer	On	8,609	8 7556	0 0000	0 0000	4 1045	0 0000	0.0000	4.1045	4.6511	0.0000	0	4.2732	0.3779
	Inter	6,312	1 1660	0 0000	0 0000	0 5336	0 0000	0.0000	0.5336	0.6324	0.0000	0	0.5683	0.0641
	Off	8,035	1 1660	0 0000	0 0000	0 5336	0 0000	0.0000	0.5336	0.6324	0.0000	0	0.5683	0.0641
Winter	On	14,650	7 6108	0 0000	0 0000	3.5710	0.0000	0.0000	3.5710	4.0398	0.0000	0	3.7134	0.3264
	Inter	11,036	1 1660	0 0000	0.0000	0 5336	0 0000	0.0000	0.5336	0.6324	0.0000	0	0.5683	0.0641
	Off	13,122	1 1660	0 0000	0.0000	0.5336	0.0000	0.0000	0.5336	0.6324	0.0000	0	0.5683	0.0641
Energy Charges														
	On	5,315,404	8 2888	1 1768	0 0000	0 2777	4 6541	0 0000	6.1086	2.1802	4.6541	247,384		2.1802
	Inter	710,757	7 2606	1 1768	0 0000	0 2777	4 0490	0 0000	5 5035	1 7571	4 0490	28,779		1.7571
	Off	4,127,510	5 6292	1 1768	0 0000	0 2777	2 4703	0 0000	3 9248	1.7044	2.4703	101,962		1.7044
Totals		10,153,671									4.84	491,199		
Special Annual Minimum														
LPL-Primary														
Service Charge		11 193	368 64	0 00	0 00	368 64	0 00	0 00	368.64	0	0	0		
		0 000	9 4800	0 0000	0 0000	9 4800	0 0000	0 0000	9 4800	0 0000	0.0000	0		
Capacity Obligation		9 960	0 0000	0 0000	0 0000	0 0000	2 9150	0 0000	2.9150	(2.9150)	2.9150	29,033		
Transmission Obligation		8,400	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1 5961	(1.5961)	1.5961	13,407		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0		
Summer	On	3,117	8 5648	0 0000	0 0000	3 1337	0 0000	0 0000	3 1337	5.4311	0.0000	0	4 3899	1.0412
	Inter	2,286	1 0494	0 0000	0 0000	0 3761	0 0000	0 0000	0 3761	0 6733	0 0000	0	0.5400	0.1333
	Off	2,910	1 0494	0 0000	0 0000	0 3761	0.0000	0.0000	0.3761	0.6733	0.0000	0	0.5400	0.1333
Winter	On	5,495	7 4306	0 0000	0 0000	2 7264	0.0000	0.0000	2.7284	4 7042	0.0000	0	3.8104	0.8938
	Inter	4,206	1 0494	0 0000	0 0000	0 3761	0.0000	0.0000	0.3761	0.6733	0.0000	0	0 5400	0.1333
	Off	5,077	1.0494	0 0000	0.0000	0.3761	0.0000	0.0000	0.3761	0.6733	0.0000	0	0.5400	0.1333
Energy Charges														
	On	2,049,715	7.5452	1 1222	0 0000	0 2661	4 4299	0.0000	5.8182	1 7270	4.4299	90,800		1.7270
	Inter	286,960	6 5689	1 1222	0 0000	0 2661	3 8594	0.0000	5.2477	1.3212	3.8594	11,075		1 3212
	Off	1,762,754	5.6096	1 1222	0.0000	0.2661	2.3650	0.0000	3.7533	1.8563	2.3650	41,689		1.8563
Totals		4,099,429									4.54	186,004		
Special Annual Minimum														
Special Provisions-LPL														
Standby-Sec.		29	3.8600	0.0000	0.1800	2.8300	0.8500	0.0000	3.8600	(0 0000)	1.0300	30		
Standby- Pri.		38	2.7300	0.0000	0.1800	1.6900	0.8700	0.0000	2.7400	(0.0100)	1.0500	40		
												70		
Area Dev. Svc Cr. Yrs 1-5-Sec.		1,158	(2.8500)	0 0000	0.0000	(2.8500)	0.0000	0.0000	(2 8500)	0.0000	0 0000	0		
Area Dev. Svc. Cr. Yrs 1-5-Pri.		300	0 0000	0 0000	0.0000	0.0000	0.0000	0 0000	0 0000	0.0000	0 0000	0		
Curt. Elec. Svc. Cr														
Curt Elec. Svc Peak Cr														
IES Cr 2 Hr. Ntc.-Sec.		36	(3 2900)	0 0000	0.0000	0.0000	(3 2900)	0.0000	(3 2900)	0 0000	(3 2900)	(118)		
IES Cr. 30 Min Ntc.-Sec.		99	(4.5300)	0 0000	0.0000	0 0000	(4 5300)	0.0000	(4 5300)	0 0000	(4 5300)	(448)		
IES Cr. 2 Hr. Ntc.-Pri.		0	(3 2900)	0 0000	0.0000	0 0000	(3 2900)	0.0000	(3 2900)	0 0000	(3 2900)	0		
IES Cr. 30 Min Ntc.-Pri.		75	(4.5300)	0.0000	0.0000	0 0000	(4.5300)	0.0000	(4 5300)	0 0000	(4 5300)	(340)		
IES Chg. 2 Hr. Ntc.												(906)		
IES Chg. 30 Min Ntc.														

1999 Unbundled Rat
Detail

			bill det. 1999 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal (8=sum 3-7)	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
HTS-Subtrans															
Service Charge			2 180	2,026 07	0 00	0 00	2,026.07	0 00	0.00	2,026.07	0	0	0		
Capacity Obligation			8,004	0 0000	0 0000	0 0000	0 0000	2 9150	0 0000	2 9150	(2.9150)	2.9150	23,332		
Transmission Obligation			6,734	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1.5961	(1.5961)	1.5961	10,746		
Demand Charges				0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0		
Summer	On		2,820	10 4834	0 0000	0 0000	1 3031	0 0000	0.0000	1 3031	9 1803	0.0000	0	4 3823	4.7980
	Inter			0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0.0000	0	0.0000	0.0000
	Off			0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0	0.0000	0.0000
Winter	On		5,429	9 5718	0 0000	0 0000	1 1858	0 0000	0 0000	1.1858	6.3860	0.0000	0	4.0010	4.3850
	Inter			0 0000	0.0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0.0000	0	0.0000	0.0000
	Off			0 0000	0 0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0	0.0000	0.0000
Energy Charges															
	On	.45	1,583,322	6 8074	1 1060	0 0000	0 1940	4 3049	0 0000	5.6049	1.2025	4.3049	66,160		1.2025
	Inter	.08	282,658	5 8365	1 1060	0 0000	0 1940	3 7459	0 0000	5 0459	0.7906	3.7459	10,588		0.7908
	Off	.46	1,615,873	5 0616	1 1060	0 0000	0 1940	2 2779	0.0000	3.5779	1.4837	2.2779	36,808		1.4637
Totals			3,481,853									4.30	149,636		
Special Annual Minimum															
HTS-High Voltage															
Service Charge			0 168	1,823 47	0 00	0 00	1,823 47	0 00	0 00	1,823 47	0	0	0		
Capacity Obligation			696	0 0000	0 0000	0 0000	0 0000	2 9150	0.0000	2 9150	(2.9150)	2.9150	2,029		
Transmission Obligation			586	0 0000	0 0000	1.5961	0 0000	0 0000	0 0000	1.5961	(1.5961)	1.5961	935		
Demand Charges				0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0		
Summer	On		324	9 4351	0 0000	0 0000	1 1728	0 0000	0 0000	1.1728	8.2623	0.0000	0	3.3337	4.9286
	Inter			0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0.0000	0	0.0000	0.0000
	Off			0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0.0000	0	0.0000	0.0000
Winter	On		619	8 6146	0 0000	0 0000	1 0686	0 0000	0.0000	1.0686	7.5460	0.0000	0	3.0437	4.5023
	Inter			0 0000	0 0000	0 0000	0.0000	0 0000	0.0000	0.0000	0.0000	0.0000	0	0.0000	0.0000
	Off			0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0	0.0000	0.0000
Energy Charges															
	On		192,419	6 0555	1 0798	0 0000	0.1940	4 2069	0.0000	5.4805	0.5750	4.2069	8,095		0.5750
	Inter		26,167	5 1816	1 0796	0.0000	0.1940	3 6615	0.0000	4.9351	0.2465	3.6615	958		0 2465
	Off		159,668	4.4842	1 0796	0.0000	0.1940	2.2291	0.0000	3.5027	0.9815	2.2291	3,564		0.9815
Totals			378,454									4.12	15,581		
Special Annual Minimum															
Special Provisions-HTS															
Standby- Subtrans.			410	1.3900	0 0000	0.1700	0.3200	0 9000	0 0000	1 3900	0.0000	1.0700	439		
Standby- High Voltage			208	1.2500	0 0000	0.1500	0.2900	0.8200	0.0000	1.2600	(0.0100)	0.9700	202		
													641		
Area Dev. Svc. Cr. Yrs 1-5-Sub			70	(1 9000)	0.0000	0 0000	(1 9000)	0 0000	0.0000	(1.9000)	0.0000	0.0000	0		
Area Dev. Svc. Cr. Yrs 1-5-HV			49	0 0000	0.0000	0.0000	0 0000	0.0000	0.0000	0 0000	0 0000	0 0000	0		
Curt Elec. Svc Cr															
Curt. Elec. Svc. Peak Cr															
IES Cr 2 Hr. Ntc.-Sub			312	(3 2900)	0 0000	0 0000	0 0000	(3 2900)	0 0000	(3 2900)	0 0000	(3 2900)	(1,026)		
IES Cr. 30 Min Ntc.-Sub			319	(4 5300)	0 0000	0.0000	0.0000	(4 5300)	0.0000	(4.5300)	0 0000	(4 5300)	(1,445)		
IES Cr 2 Hr. Ntc.-HV			0	(3.2900)	0.0000	0.0000	0.0000	(3 2900)	0.0000	(3 2900)	0.0000	(3.2900)	0		
IES Cr. 30 Min Ntc.-HV			779	(4.5300)	0.0000	0.0000	0.0000	(4.5300)	0.0000	(4.5300)	0.0000	(4 5300)	(3,529)		
IES Chg. 2 Hr. Ntc.													(6,000)		
IES Chg 30 Min Ntc.															

1999 Unbundled Rates
Detail

	bill det. 1999 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal (8=sum 3-7)	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
BPL	306,693	17 3316	1 1768	0 0000	10 7704	2 8324	0 0000	14.7796	2 5520	2.8324	8,687		
	306,693									2.83	8,687		
PSAL	147,752	21 8335	1 1768	0 0000	13 3919	2.8324	0 0000	17.4011	4.4324	2.8324	4,185		
	147,752									2.83	4,185		

2000 Unbundled Rat.
Detail

		bill det. 2000 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig.Adj. (12)	Adj MTC (13)
RS														
Service Charge		20,447 304	2 41	0 00	0 00	2 41	0.00	0.00	2.41	0.00	0.00	0		
Energy Charges														
	0-600	8,157,618	11 6394	1 1768	0 6624	3 2744	5 1438	1 0315	11 2889	0 3505	5.8062	473,648		
	Over 600 Sum	1,481,505	13 1022	1 1768	0 6624	3 6795	6 0451	1 0315	12.5953	0.5069	6 7075	99,372		
	Over 600 Win	1,161,377	11 0607	1 1768	0 6624	3 1008	4 4949	1.0315	10.4664	0.5943	5.1573	59,896		
Totals		10,800,500									5.86	632,916		
RHS														
Service Charge		118 282	2 41	0 00	0 00	2 41	0.00	0.00	2.41	0.00	0.00	0		
Energy Charges														
	0-600	73,336	11 6394	1 1768	0 3340	4 0895	4.0734	1.0315	10.7052	0 9342	4.4074	3,232		
	Over 600 Sum	11,343	13 1022	1 1768	0 3340	4 6089	5 2783	1 0315	12.4295	0.6727	5.6123	637		
	Over 600 Win	70,153	8 0174	1 1768	0 3340	2 8285	3 6656	1 0315	9 0364	(1 0190)	3 9996	2,806		
	Common	0	13 1022	1 1768	0 3340	4 6089	5 2783	1 0315	12 4295	0.6727	5 6123	0		
Totals		154 832									4.31	6,675		
RLM														
Service Charge		59 281	12 12	0 00	0 00	12 12	0 00	0 00	12 12	0 00	0 00	0		
Service Charge over 20,000		120 359	6 79	0 00	0 00	6 79	0 00	0 00	6 79	0 00	0 00	0		
Service Charge Sp. Prv. (i)														
Energy Charges														
Summer	On	60 478	17 6369	1 1768	0 5520	3 7675	7 5734	1 0315	14 1012	3 5357	8 1254	4,914		
	Inter	11 340	16 1126	1 1768	0 5520	3 2418	6 4945	1 0315	12.4966	3 6160	7 0465	799		
	Off	54 178	6 3140	1 1768	0 5520	1 2092	3 8617	1 0315	7 8312	(1 5172)	4 4137	2,391		
Winter	On	80 426	12 0486	1 1768	0 5520	2 6110	4 8636	1 0315	10 2349	1.8137	5.4156	4,358		
	Inter	16 451	12 2680	1 1768	0 5520	2 4708	4 5348	1 0315	9 7659	2.5021	5 0868	837		
	Off	85.909	6 3140	1 1768	0 5520	1 2092	3 5401	1 0315	7.5096	(1 1956)	4 0921	3,515		
Totals		308,782									5.44	16,812		
WH														
Energy Charge		9,890	10 1713	1 1768	0 0000	5.2921	2.5725	1.0315	10.0729	0.0984	2.5725	254		
Totals		9,890									2.57	254		
WHS														
Service Charge		1.165	2.82	0.00	0.00	2.82	0.00	0.00	2.82	0.00	0.00	0.000		
Energy Charge		218	5 4289	1.1768	0 0000	1.5340	2.5749	1.0315	6 3172	(0.8883)	2.5749	5.613		
Totals		218									2.57	5.613		

STC, preliminary values, adjusted at least annually.

2000 Unbundled Rate.
Detail

		bill det. 2000 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
GLP														
Service Charge		2,844 257	4 04	0 00	0 00	4 04	0 00	0 00	4.04	0	0	0		
Service Charge- Night Use		1 224	367 08	0 00	0 00	367 08	0.00	0.00	367.08	0	0	0		
Capacity Obligation		25.620	0 0000	0 0000	0 0000	0 0000	3 0033	0 0000	3.0033	(3.0033)	3 0033	76,945		
Transmission Obligation		21.564	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1.5961	(1.5961)	1.5961	34,418		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0		
Summer	0-1	716	4 8666	0 0000	0 0000	3 0170	0 0000	0 0000	3.0170	1 8696	0.0000	0	1.9617	(0.0921)
	over 1	10,869	9 5930	0 0000	0 0000	5 9158	0 0000	0 0000	5.9158	3.6772	0.0000	0	3.8541	(0.1769)
Winter	0-1	1,437	4 8866	0 0000	0 0000	3.0170	0 0000	0.0000	3.0170	1 8696	0.0000	0	1.9617	(0.0921)
	over 1	19,195	8.4588	0.0000	0 0000	5 2059	0 0000	0.0000	5.2059	3.2529	0.0000	0	3.3993	(0.1464)
Energy Charges														
	All Use-x night use	8,127,093	8 2050	1 1768	0 0000	0 3583	3.9852	1 0315	6.5518	1.6532	3 9852	323,881		1.6532
	Night Use	54,305	7 0751	1 1768	0 0000	0 3583	3 9852	1 0315	6.5518	0.5233	3.9852	2,164		0.5233
Totals		8,181,398									5.35	437,408		
Monthly Minimum, MD														
Special Annual Minimum														
Special Provisions														
Standby		2 000	3 8600	0 0000	0 1800	2 8900	0 7800	0 0000	3.8500	0.0100	0.9600	2		
Area Dev Svc Cr Yrs 1-5		357	(2 8500)	0 0000	0 0000	(2 8500)	0 0000	0 0000	(2.8500)	0.0000	0.0000	0		
Area Dev. Svc Cr Yrs 6&7														
Curt Elec Svc Cr														
Curt. Elec. Svc Peak Cr														
Police/Fire-Each														
Police/Fire-Minimum														
HS														
Energy Charges														
	Summer	4,526	14 2258	1 1768	0 3921	5.7003	5 3378	1 0315	13 6385	0.5873	5.7299	259		
	Winter	24,787	10.9897	1.1768	0.3921	4 3648	3.7981	1.0315	10.7633	0.2264	4.1902	1,039		
Totals		29,313									4.43	1,298		

2000 Unbundled Rat
Detail

		bill det. 2000 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig.Adj. (12)	Adj MTC (13)
LPL-Secondary														
Service Charge		78 203	368 64	0 00	0 00	368 64	0.00	0.00	368.64	0	0	0		
Capacity Obligation		26,760	0 0000	0 0000	0 0000	0 0000	3 0033	0 0000	3.0033	(3 0033)	3 0033	80,368		
Transmission Obligation		22,536	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1 5961	(1.5961)	1.5961	35,970		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0.0000	0		
Summer	On	8,744	8 7556	0 0000	0 0000	4 1045	0 0000	0.0000	4 1045	4.6511	0.0000	0	4.3311	0.3200
	Inter	6,411	1 1660	0 0000	0 0000	0 5336	0 0000	0.0000	0 5336	0.6324	0 0000	0	0.5760	0.0564
	Off	8,161	1 1660	0 0000	0 0000	0 5336	0 0000	0 0000	0 5336	0.6324	0.0000	0	0.5760	0.0564
Winter	On	14,866	7 6108	0 0000	0 0000	3 5710	0 0000	0 0000	3.5710	4.0398	0.0000	0	3.7637	0.2761
	Inter	11,199	1 1660	0 0000	0 0000	0.5336	0.0000	0 0000	0.5336	0.6324	0.0000	0	0.5760	0.0564
	Off	13,316	1 1660	0 0000	0 0000	0 5336	0 0000	0.0000	0.5336	0.6324	0.0000	0	0.5760	0.0564
Energy Charges														
	On	5,400,391	8 2888	1 1768	0 0000	0 2777	4 6919	1.0315	7 1779	1.1109	4.6919	253,381		1.1109
	Inter	722.121	7 2606	1 1768	0 0000	0 2777	4 0824	1 0315	6 5684	0.6922	4.0824	29,480		0.6922
	Off	4,193.507	5 6292	1 1768	0 0000	0 2777	2.4924	1 0315	4.9784	0.6508	2.4924	104,519		0.6508
Totals		10,316.019									4.88	503,718		
Special Annual Minimum														
LPL-Primary														
Service Charge		11 277	368 64	0 00	0 00	368 64	0 00	0.00	368.64	0	0	0		
		0 000	9 4800	0 0000	0 0000	9 4800	0 0000	0 0000	9 4800	0 0000	0.0000	0		
Capacity Obligation		9.972	0 0000	0 0000	0 0000	0 0000	3 0033	0 0000	3.0033	(3.0033)	3.0033	29,949		
Transmission Obligation		8.400	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1.5961	(1.5961)	1.5961	13,407		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0.0000	0		
Summer	On	3.146	8 5648	0 0000	0 0000	3 1337	0 0000	0.0000	3 1337	5.4311	0.0000	0	4.4445	0.9866
	Inter	2.307	1 0494	0 0000	0 0000	0 3761.	0 0000	0.0000	0.3761	0.6733	0.0000	0	0 5467	0.1266
	Off	2,936	1 0494	0 0000	0 0000	0 3761	0 0000	0.0000	0.3761	0.6733	0.0000	0	0.5467	0.1268
Winter	On	5,544	7 4306	0 0000	0 0000	2 7264	0 0000	0,0000	2.7264	4 7042	0.0000	0	3.8578	0.8464
	Inter	4,243	1.0494	0 0000	0 0000	0 3761	0.0000	0.0000	0.3761	0.6733	0.0000	0	0.5467	0.1266
	Off	5,121	1 0494	0.0000	0 0000	0 3761	0.0000	0.0000	0.3761	0.6733	0.0000	0	0 5467	0.1266
Energy Charges														
	On	2,068,759	7 5452	1.1222	0 0000	0 2661	4.4658	1.0315	6.8856	0.6596	4.4658	92,387		0.6596
	Inter	289,626	6 5689	1 1222	0 0000	0 2661	3.8912	1.0315	6.3110	0.2579	3.8912	11,270		0.2579
	Off	1,779,133	5 6096	1 1222	0.0000	0 2661	2.3862	1.0315	4.8060	0.8036	2.3862	42.454		0.8036
Totals		4,137,518									4.58	189,467		
Special Annual Minimum														
Special Provisions-LPL														
Standby-Sec.		29	3.8600	0 0000	0 1800	2 8300	0.8500	0.0000	3 8600	(0 0000)	1.0300	30		
Standby- Pri.		38	.2.7300	0 0000	0.1800	1.6900	0.8700	0.0000	2.7400	(0.0100)	1.0500	40		
												70		
Area Dev. Svc. Cr. Yrs 1-5-Sec.		1,158	(2.8500)	0 0000	0 0000	(2.8500)	0 0000	0.0000	(2 8500)	0.0000	0.0000	0		
Area Dev. Svc. Cr. Yrs 1-5-Pri.		300	0.0000	0 0000	0 0000	0 0000	0.0000	0.0000	0 0000	0.0000	0.0000	0		
Curt Elec. Svc. Cr														
Curt. Elec. Svc. Peak Cr														
IES Cr. 2 Hr. Ntc.-Sec.		36	(3 2900)	0.0000	0 0000	0 0000	(3 2900)	0 0000	(3 2900)	0 0000	(3 2900)	(118)		
IES Cr. 30 Min Ntc.-Sec.		99	(4 5300)	0.0000	0 0000	0 0000	(4 5300)	0 0000	(4.5300)	0.0000	(4 5300)	(448)		
IES Cr. 2 Hr. Ntc.-Pri.		0	(3 2900)	0 0000	0 0000	0 0000	(3 2900)	0.0000	(3 2900)	0 0000	(3 2900)	0		
IES Cr. 30 Min Ntc.-Pri.		75	(4 5300)	0.0000	0.0000	0.0000	(4 5300)	0.0000	(4 5300)	0.0000	(4 5300)	(340)		
IES Chg. 2 Hr. Ntc.												(906)		
IES Chg. 30 Min Ntc.														

2000 Unbundled Rate.
Detail

		bill det. 2000 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)	
HTS-Subtrans															
Service Charge		2 192	2,026 07	0 00	0.00	2,026 07	0.00	0.00	2,026.07	0	0	0			
Capacity Obligation		8,038	0 0000	0 0000	0 0000	0 0000	3 0033	0.0000	3 0033	(3 0033)	3.0033	24,141			.69
Transmission Obligation		6,768	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1.5961	(1.5961)	1.5961	10,802			.31
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0,0000	0.0000	0			
Summer	On	2,835	10 4834	0 0000	0 0000	1 3031	0 0000	0.0000	1.3031	9.1803	0.0000	0	4.4700	4.7103	
	Inter		0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0.0000	0.0000	0	0.0000	0.0000	
	Off		0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0.0000	0.0000	0	0.0000	0.0000	
Winter	On	5,457	9 5718	0 0000	0 0000	1 1858	0 0000	0.0000	1 1858	8.3860	0.0000	0	4.0811	4.3049	
	Inter		0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0.0000	0.0000	0	0.0000	0.0000	
	Off		0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0 0000	0.0000	0.0000	0	0.0000	0.0000	
Energy Charges															
	On	1,587,774	6 8074	1 1060	0 0000	0 1940	4 3401	1 0315	6 6716	0.1358	4 3401	68,911		0.1358	
	Inter	283.453	5 8365	1 1060	0 0000	0 1940	3 7771	1 0315	6 1086	(0.2721)	3.7771	10,706		(0.2721)	
	Off	1,620 416	5 0616	1 1060	0 0000	0 1940	2 2987	1 0315	4.6302	0.4314	2.2987	37,249		0.4314	
Totals		3,491,643									4.35	151,809			
Special Annual Minimum															
HTS-High Voltage															
Service Charge		0 168	1 823 47	0 00	0 00	1,823 47	0 00	0 00	1,823 47	0	0	0			
Capacity Obligation		698	0 0000	0 0000	0 0000	0 0000	3 0033	0 0000	3.0033	(3.0033)	3.0033	2,096			
Transmission Obligation		588	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1 5961	(1 5961)	1.5961	939			
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0 0000	0.0000	0			
Summer	On	326	9 4351	0 0000	0 0000	1 1728	0 0000	0 0000	1 1728	8 2623	0.0000	0	3.3918	4.8705	
	Inter		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0	0.0000	0.0000	
	Off		0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0.0000	0	0.0000	0.0000	
Winter	On	623	8 6146	0 0000	0 0000	1 0686	0 0000	0 0000	1.0686	7.5460	0.0000	0	3 0987	4.4493	
	Inter		0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0.0000	0.0000	0	0.0000	0,0000	
	Off		0 0000	0 0000	0.0000	0 0000	0.0000	0.0000	0.0000	0.0000	0.0000	0	0.0000	0.0000	
Energy Charges															
	On	192,959	6 0555	1 0796	0 0000	0.1940	4.2413	1 0315	6.5464	(0.4909)	4.2413	8,184		(0.4909)	
	Inter	26,240	5.1816	1 0796	0 0000	0 1940	3.6918	1.0315	5.9969	(0.8153)	3.6918	969		(0 8153)	
	Off	160,317	4.4842	1.0796	0.0000	0 1940	2.2493	1.0315	4.5544	(0.0702)	2.2493	3,606		(0.0702)	
Totals		379,516									4.16	15,794			
Special Annual Minimum															
Special Provisions-HTS															
Standby- Subtrans.		410	1.3900	0.0000	0.1700	0.3200	0.9000	0.0000	1 3900	0.0000	1 0700	439			
Standby- High Voltage		208	1.2500	0.0000	0.1500	0.2900	0.8200	0.0000	1.2600	(0.0100)	0.9700	202			
												641			
Area Dev. Svc. Cr. Yrs 1-5-Sub		70	(1 9000)	0 0000	0 0000	(1.9000)	0 0000	0 0000	(1.9000)	0.0000	0 0000	0			
Area Dev. Svc. Cr. Yrs 1-5-HV		49	0 0000	0 0000	0.0000	0.0000	0 0000	0 0000	0.0000	0.0000	0 0000	0			
Curt Elec Svc Cr															
Curt. Elec Svc. Peak Cr															
IES Cr 2 Hr. Ntc.-Sub		312	(3.2900)	0.0000	0 0000	0.0000	(3.2900)	0.0000	(3 2900)	0 0000	(3 2900)	(1,026)			
IES Cr. 30 Min Ntc.-Sub		319	(4 5300)	0 0000	0 0000	0.0000	(4 5300)	0 0000	(4 5300)	0 0000	(4.5300)	(1,445)			
IES Cr. 2 Hr. Ntc.-HV		0	(3.2900)	0 0000	0 0000	0.0000	(3 2900)	0.0000	(3 2900)	0 0000	(3 2900)	0			
IES Cr. 30 Min Ntc.-HV		779	(4.5300)	0.0000	0.0000	0.0000	(4 5300)	0 0000	(4 5300)	0 0000	(4.5300)	(3,529)			
IES Chg 2 Hr. Ntc.												(6,000)			
IES Chg. 30 Min Ntc.															

2000 Unbundled Rate
Detail

	bill det. 2000 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
BPL	310,201	17 3316	1 1768	0 0000	10 7704	2 8571	1.0315	15.8358	1.4958	2.8571	8,863		
	310,201									2.86	8,863		
PSAL	152,172	21 8335	1 1768	0 0000	13 3919	2 8571	1.0315	18.4573	3.3762	2.8571	4,348		
	152,172									2.86	4,348		

2001 Unbundled Rate
Detail

		bill det. 2001 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
RS														
	Service Charge	20,664 277	2 41	0 00	0 00	2 41	0 00	0 00	2.41	0 00	0.00	0		
	Energy Charges													
	0-600	8,346,624	11 6394	1 1768	0 6585	3 2744	5 1461	1.0199	11.2757	0.3637	5.8046	484,486		
	Over 600 Sum	1,515,830	13 1022	1 1768	0 6585	3 6795	6 0602	1 0199	12 5949	0.5073	6.7187	101,844		
	Over 600 Win	1,188,286	11 0607	1 1768	0 6585	3 1008	4 4880	1.0199	10.4440	0.6167	5.1465	61,155		
	Totals	11,050,740									5.86	647,487		
RHS														
	Service Charge	34 044	2 41	0 00	0.00	2.41	0 00	0.00	2.41	0.00	0.00	0		
	Energy Charges													
	0-600	26,137	11 6394	1 1768	0 3124	4.0895	4 0532	1.0199	10.6518	0.9876	4.3656	1,141		
	Over 600 Sum	4,043	13 1022	1 1768	0 3124	4.6089	5.2753	1.0199	12.3933	0.7089	5.5877	226		
	Over 600 Win	25,003	8 0174	1 1768	0 3124	2 8285	3 6397	1.0199	8.9773	(0.9599)	3.9521	988		
	Common	0	13 1022	1 1768	0 3124	4 6089	5 2753	1.0199	12.3933	0.7089	5.5877	0		
	Totals	55,183									4.27	2,355		
RLM														
	Service Charge	58 933	12 12	0 00	0 00	12 12	0 00	0 00	12 12	0.00	0.00	0		
	Service Charge over 20,000	119 652	6 79	0 00	0 00	6 79	0 00	0 00	6.79	0.00	0.00	0		
	Service Charge Sp. Prv. (I)													
	Energy Charges													
	Summer On	59,453	17 6369	1 1768	0 5490	3 7675	7 6199	1 0199	14.1331	3.5038	8.1689	4,857		
	Inter	11,148	16 1126	1 1768	0 5490	3 2418	6 5258	1 0199	12.5133	3.5993	7.0748	789		
	Off	53,260	6 3140	1 1768	0 5490	1 2092	3 8556	1.0199	7.8105	(1.4965)	4.4046	2,346		
	Winter On	79,063	12 0486	1 1768	0 5490	2 6110	4 8718	1 0199	10.2285	1 8201	5.4208	4,286		
	Inter	16,172	12 2680	1 1768	0 5490	2 4708	4 5383	1 0199	9.7548	2.5132	5.0873	823		
	Off	84,454	6 3140	1 1768	0 5490	1 2092	3.5294	1.0199	7.4843	(1.1703)	4.0784	3,444		
	Totals	303,550									5.45	16,545		
WH														
	Energy Charge	8,512	10 1713	1 1768	0 0000	5 2921	2 5681	1.0199	10.0569	0.1144	2.5681	219		
	Totals	8,512									2.57	219		
WHS														
	Service Charge	1.068	2.82	0.00	0.00	2.82	0.00	0.00	2.82	0.00	0.00	0.000		
	Energy Charge	191	5.4289	1 1768	0.0000	1.5340	2.5705	1.0199	6.3012	(0.8723)	2.5705	4 910		
	Totals	191									2.57	4.910		

STC, preliminary values, adjusted at least annually.

2001 Unbundled Rate
Detail

			bill det. 2001 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig.Adj. (12)	Adj MTC (13)
GLP															
	Service Charge		2,862 877	4 04	0 00	0 00	4 04	0 00	0 00	4.04	0	0	0		
	Service Charge- Night Use		1 104	367 08	0 00	0 00	367 08	0.00	0.00	367.08	0	0	0		
	Capacity Obligation		25,884	0 0000	0 0000	0 0000	0 0000	3 0033	0.0000	3.0033	(3.0033)	3.0033	77,737		
	Transmission Obligation		21,432	0 0000	0 0000	1 5961	0 0000	0.0000	0.0000	1.5961	(1.5961)	1.5961	34,208		
	Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0.0000	0		
	Summer	0-1	725	4 8866	0 0000	0 0000	3 0170	0 0000	0.0000	3.0170	1.8698	0.0000	0	1.9468	(0.0772)
		over 1	11,007	9 5930	0 0000	0 0000	5 9158	0 0000	0.0000	5.9158	3 6772	0.0000	0	3.8248	(0.1476)
	Winter	0-1	1,455	4 8866	0 0000	0 0000	3.0170	0 0000	0.0000	3.0170	1.8696	0.0000	0	1 9468	(0.0772)
		over 1	19,446	8 4588	0 0000	0 0000	5.2059	0.0000	0.0000	5.2059	3.2529	0.0000	0	3.3735	(0.1206)
	Energy Charges														
		All Use-x night use	8,249,900	8 2050	1 1768	0 0000	0 3583	4 0424	1.0199	6.5974	1 6076	4.0424	333,494		1.6076
		Night Use	48,536	7 0751	1 1768	0 0000	0 3583	4 0424	1.0199	6.5974	0.4777	4.0424	1,962		0.4777
	Totals		8,298,436									5.39	447,401		
	Monthly Minimum, MD														
	Special Annual Minimum														
	Special Provisions														
	Standby		2 000	3 8600	0 0000	0 1800	2 8900	0 7800	0 0000	3 8500	0 0100	0.9600	2		
	Area Dev Svc Cr Yrs 1-5		357	(2 8500)	0 0000	0 0000	(2 8500)	0 0000	0 0000	(2 8500)	0 0000	0 0000	0		
	Area Dev Svc Cr Yrs 6&7														
	Curt Elec Svc Cr														
	Curt Elec Svc Peak Cr														
	Police/Fire-Each														
	Police/Fire-Minimum														
HS															
	Energy Charges														
		Summer	4,366	14 2258	1 1768	0 4063	5.7003	5 4334	1.0199	13.7367	0.4891	5.8397	255		
		Winter	23,917	10.9897	1 1768	0.4063	4.3648	3 8718	1.0199	10.8398	0.1501	4.2781	1,023		
	Totals		28,283									4.52	1,278		

2001 Unbundled Rat
Detail

		bill det. 2001 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig.Adj. (12)	Adj MTC (13)
LPL-Secondary														
Service Charge		79 006	368 64	0 00	0 00	368 64	0 00	0.00	368.64	0	0	0		
Capacity Obligation		27,036	0 0000	0 0000	0 0000	0 0000	3 0033	0 0000	3 0033	(3.0033)	3 0033	81,197		
Transmission Obligation		22,740	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1 5961	(1 5961)	1.5961	36,295		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0		
Summer	On	8,879	8 7556	0 0000	0 0000	4 1045	0 0000	0 0000	4 1045	4 6511	0 0000	0	4.3097	0.3414
	Inter	6,510	1 1660	0 0000	0 0000	0 5336	0 0000	0 0000	0.5336	0 6324	0.0000	0	0 5732	0.0592
	Off	8,287	1 1660	0 0000	0 0000	0 5336	0 0000	0 0000	0.5336	0.6324	0.0000	0	0.5732	0.0592
Winter	On	15,083	7 6108	0 0000	0 0000	3 5710	0 0000	0 0000	3.5710	4.0398	0.0000	0	3 7451	0.2947
	Inter	11,362	1 1660	0 0000	0 0000	0 5336	0 0000	0 0000	0.5336	0 6324	0.0000	0	0.5732	0.0592
	Off	13,510	1 1660	0 0000	0 0000	0.5336	0 0000	0.0000	0.5336	0.6324	0.0000	0	0.5732	0.0592
Energy Charges														
	On	5,485,658	8 2888	1 1768	0 0000	0 2777	4 7590	1 0199	7 2334	1 0554	4.7590	261,062		1.0554
	Inter	733,523	7 2606	1 1768	0 0000	0 2777	4 1410	1 0199	6 6154	0.6452	4.1410	30,375		0.6452
	Off	4,259,721	5 6292	1 1768	0 0000	0 2777	2 5284	1 0199	5.0028	0.6264	2 5284	107,703		0.8264
Totals		10,478,902									4.93	516,632		
Special Annual Minimum														
LPL-Primary														
Service Charge		11 374	368 64	0 00	0 00	368 64	0 00	0.00	368.64	0	0	0		
		0 000	9 4800	0 0000	0 0000	9 4800	0 0000	0 0000	9 4800	0 0000	0.0000	0		
Capacity Obligation		10 008	0 0000	0 0000	0 0000	0 0000	3 0033	0 0000	3 0033	(3.0033)	3.0033	30,057		
Transmission Obligation		8.424	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1 5961	(1.5961)	1 5961	13,446		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0		
Summer	On	3,173	8 5648	0 0000	0 0000	3 1337	0 0000	0 0000	3 1337	5.4311	0.0000	0	4 4227	1.0084
	Inter	2,327	1 0494	0 0000	0 0000	0 3761	0 0000	0 0000	0.3761	0 6733	0.0000	0	0 5440	0.1293
	Off	2,962	1 0494	0 0000	0 0000	0 3761	0 0000	0.0000	0 3761	0 6733	0.0000	0	0.5440	0.1293
Winter	On	5,589	7 4306	0 0000	0 0000	2 7264	0 0000	0 0000	2 7264	4 7042	0.0000	0	3.8389	0.8653
	Inter	4,278	1 0494	0 0000	0 0000	0 3761	0 0000	0 0000	0 3761	0.6733	0.0000	0	0.5440	0.1293
	Off	5,164	1 0494	0 0000	0.0000	0.3761	0 0000	0.0000	0.3761	0.6733	0.0000	0	0.5440	0.1293
Energy Charges														
	On	2,086,870	7.5452	1 1222	0 0000	0.2661	4 5297	1.0199	6 9379	0 6073	4.5297	94,529		0.6073
	Inter	292,162	6.5689	1 1222	0 0000	0 2661	3.9470	1.0199	6 3552	0.2137	3.9470	11,532		0 2137
	Off	1,794,708	5.6096	1.1222	0.0000	0 2661	2 4206	1.0199	4.8288	0.7808	2.4206	43,443		0.7808
Totals		4,173,740									4.62	193,007		
Special Annual Minimum														
Special Provisions-LPL														
Standby-Sec.		29	3 8600	0 0000	0.1800	2.8300	0.8500	0.0000	3.8600	(0 0000)	1.0300	30		
Standby- Pri.		38	2.7300	0.0000	0.1800	1 6900	0.8700	0.0000	2.7400	(0.0100)	1 0500	40		
												70		
Area Dev. Svc. Cr Yrs 1-5-Sec.		1,158	(2 8500)	0 0000	0.0000	(2 8500)	0.0000	0.0000	(2 8500)	0.0000	0.0000	0		
Area Dev. Svc. Cr. Yrs 1-5-Pri.		300	0 0000	0 0000	0.0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0		
Curt. Elec. Svc. Cr														
Curt. Elec. Svc. Peak Cr														
IES Cr. 2 Hr. Ntc.-Sec.		36	(3.2900)	0 0000	0.0000	0 0000	(3 2900)	0.0000	(3 2900)	0 0000	(3 2900)	(118)		
IES Cr. 30 Min Ntc.-Sec.		99	(4 5300)	0 0000	0.0000	0.0000	(4 5300)	0 0000	(4 5300)	0 0000	(4 5300)	(448)		
IES Cr. 2 Hr. Ntc.-Pri.		0	(3 2900)	0 0000	0.0000	0 0000	(3 2900)	0 0000	(3 2900)	0 0000	(3 2900)	0		
IES Cr. 30 Min Ntc.-Pri.		75	(4.5300)	0.0000	0.0000	0.0000	(4.5300)	0.0000	(4 5300)	0 0000	(4 5300)	(340)		
IES Chg. 2 Hr. Ntc.												(906)		
IES Chg 30 Min Ntc.														

ATTACHMENT 2

2001 Unbundled Rate
Detail

		bill det. 2001 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig.Adj. (12)	Adj MTC (13)
HTS-Subtrans														
Service Charge		2 203	2,026 07	0 00	0 00	2,026 07	0.00	0.00	2,026.07	0	0	0		
Capacity Obligation		7,894	0 0000	0 0000	0 0000	0 0000	3 0033	0 0000	3.0033	(3.0033)	3.0033	23,708		
Transmission Obligation		6,646	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1.5961	(1 5961)	1.5961	10,608		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0.0000	0.0000	0		
Summer	On	2,803	10 4834	0 0000	0 0000	1 3031	0 0000	0 0000	1.3031	9.1803	0 0000	0	4 4417	4.7386
	Inter		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0	0.0000	0.0000
	Off		0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0 0000	0 0000	0	0.0000	0.0000
Winter	On	5,392	9 5718	0 0000	0 0000	1 1858	0 0000	0.0000	1 1858	8.3860	0.0000	0	4.0553	4.3307
	Inter		0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0.0000	0	0 0000	0.0000
	Off		0 0000	0 0000	0.0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0	0.0000	0.0000
Energy Charges														
	On	1,560,374	6 8074	1 1060	0 0000	0 1940	4 4027	1 0199	6.7226	0.0848	4.4027	68,699		0.0848
	Inter	278,562	5 8365	1 1060	0 0000	0 1940	3 8319	1 0199	6 1518	(0 3153)	3.8319	10,674		(0 3153)
	Off	1,592,452	5 0616	1 1060	0 0000	0 1940	2 3324	1 0199	4.6523	0.4093	2 3324	37,142		0.4093
Totals		3,431,388									4.40	150,831		
Special Annual Minimum														
HTS-High Voltage														
Service Charge		0 169	1 823 47	0 00	0 00	1,823 47	0 00	0.00	1,823.47	0	0	0		
Capacity Obligation		686	0 0000	0 0000	0 0000	0 0000	3 0033	0 0000	3 0033	(3.0033)	3.0033	2,060		
Transmission Obligation		578	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1 5961	(1.5961)	1.5961	923		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0		
Summer	On	323	9 4351	0 0000	0 0000	1 1728	0 0000	0 0000	1 1728	8.2623	0.0000	0	3 3725	4 8898
	Inter		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0	0.0000	0.0000
	Off		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0	0.0000	0.0000
Winter	On	615	8 6146	0 0000	0 0000	1 0686	0 0000	0.0000	1.0686	7.5460	0.0000	0	3.0791	4.4669
	Inter		0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0 0000	0.0000	0.0000	0	0 0000	0.0000
	Off		0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0	0.0000	0.0000
Energy Charges														
	On	189,629	6 0555	1 0796	0.0000	0 1940	4 3025	1.0199	6.5960	(0 5405)	4.3025	8,159		(0 5405)
	Inter	25,787	5 1816	1 0796	0 0000	0 1940	3 7452	1 0199	6 0387	(0.8571)	3.7452	966		(0.8571)
	Off	157,551	4 4842	1 0796	0 0000	0.1940	2 2821	1.0199	4.5756	(0.0914)	2 2821	3,595		(0.0914)
Totals		372,967									4.21	15,703		
Special Annual Minimum														
Special Provisions-HTS														
Standby- Subtrans.		410	1 3900	0 0000	0 1700	0 3200	0 9000	0 0000	1 3900	0 0000	1.0700	439		
Standby- High Voltage		208	1 2500	0.0000	0 1500	0.2900	0.8200	0.0000	1.2600	(0.0100)	0.9700	202		
												641		
Area Dev. Svc. Cr Yrs 1-5-Sub		70	(1.9000)	0.0000	0 0000	(1 9000)	0 0000	0.0000	(1 9000)	0.0000	0 0000	0		
Area Dev Svc. Cr. Yrs 1-5-HV		49	0 0000	0 0000	0.0000	0 0000	0 0000	0.0000	0 0000	0 0000	0.0000	0		
Curt. Elec. Svc Cr														
Curt. Elec. Svc Peak Cr														
IES Cr. 2 Hr. Ntc.-Sub		312	(3.2900)	0 0000	0 0000	0 0000	(3 2900)	0 0000	(3.2900)	0 0000	(3 2900)	(1,026)		
IES Cr. 30 Min Ntc.-Sub		319	(4.5300)	0 0000	0 0000	0 0000	(4 5300)	0 0000	(4 5300)	0.0000	(4 5300)	(1,445)		
IES Cr. 2 Hr. Ntc.-HV		0	(3 2900)	0.0000	0,0000	0 0000	(3 2900)	0 0000	(3 2900)	0 0000	(3 2900)	0		
IES Cr. 30 Min Ntc.-HV		779	(4 5300)	0.0000	0.0000	0.0000	(4 5300)	0.0000	(4 5300)	0 0000	(4 5300)	(3,529)		
IES Chg. 2 Hr. Ntc.												(6,000)		
IES Chg. 30 Min Ntc.														

2001 Unbundled Rates
Detail

	bill det. 2001 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
BPL	313,710	17 3316	1 1768	0 0000	10 7704	2 8983	1.0199	15.8654	1.4662	2.8983	9,092		
	313,710									**2.90**	9,092		
PSAL	155,961	21 0335	1 1768	0 0000	13 3919	2 8983	1 0199	18.4869	3.3466	2.8983	4,520		
	155,961									**2.90**	4,520		

ATTACHMENT 2
PAGE 25 OF 40

2002a Unbundled Ra
Detail

			bill det. 2002 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
RS															
	Service Charge		20,832 180	2 41	0 00	0 00	2 41	0 00	0 00	2.41	0 00	0.00	0		
	Energy Charges														
		0-600	8,488,719	11 6394	1 1768	0 6550	3 2744	5 1540	1 0069	11.2671	0 3723	5 8090	493,110		
		Over 600 Sum	1,541,636	13 1022	1 1768	0 6550	3 6795	6 0712	1 0069	12.5894	0 5128	6.7262	103,694		
		Over 600 Win	1,208,515	11 0607	1 1768	0 6550	3 1008	4 4935	1.0069	10.4330	0.6277	5.1485	62,220		
	Totals		11,238,870									5.86	659,024		
RHS															
	Service Charge		0 000												
	Energy Charges														
		0-600	0												
		Over 600 Sum	0												
		Over 600 Win	0												
		Common	0												
	Totals		0												
RLM															
	Service Charge		58 585	12 12	0 00	0 00	12 12	0 00	0 00	12 12	0.00	0.00	0		
	Service Charge over 20,000		118 944	6 79	0 00	0 00	6 79	0 00	0 00	6 79	0.00	0.00	0		
	Service Charge Sp. Prv. (I)														
	Energy Charges														
	Summer	On	58,498	17 6369	1 1768	0 5451	3 7675	7 6338	1 0069	14.1301	3.5068	8.1789	4,784		
		Inter	10,968	16 1126	1 1768	0 5451	3 2418	6 5359	1.0069	12.5065	3.6061	7.0810	777		
		Off	52,405	6 3140	1 1768	0 5451	1 2092	3 8563	1.0069	7.7943	(1.4803)	4.4014	2,307		
	Winter	On	77,793	12 0486	1 1768	0 5451	2 6110	4.8761	1.0069	10 2159	1.8327	5.4212	4,217		
		Inter	15,912	12 2680	1 1768	0 5451	2 4708	4 5415	1 0069	9.7411	2.5269	5.0866	809		
		Off	83,097	6 3140	1 1768	0.5451	1 2092	3 5290	1.0069	7.4670	(1.1530)	4.0741	3,385		
	Totals		298,673									5.45	16,279		
WH															
	Energy Charge		7,194	10.1713	1.1768	0 0000	5.2921	2.5370	1.0069	10.0128	0.1585	2.5370	183		
	Totals		7,194									2.54	183		
WHS															
	Service Charge		0 960	2.82	0.00	0.00	2.82	0.00	0.00	2.82	0.00	0.00	0.000		
	Energy Charge		166	5.4289	1.1768	0.0000	1.5340	2 5394	1.0069	6.2571	(0.8282)	2.5394	4.215		
	Totals		166									2.54	4 215		

STC, preliminary values, adjusted at least annually.

2002a Unbundled Ra.
Detail

	bill det. 2002 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
GLP													
Service Charge	2,881 491	4 04	0 00	0 00	4 04	0 00	0 00	4 04	0	0	0		
Service Charge- Night Use	0 984	367 08	0 00	0 00	367 08	0 00	0.00	367.08	0	0	0		
Capacity Obligation	26,160	0 0000	0 0000	0 0000	0 0000	3 0917	0 0000	3 0917	(3.0917)	3 0917	80,879		
Transmission Obligation	22,020	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1 5961	(1.5961)	1.5961	35,146		
Demand Charges		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0		
Summer 0-1	734	4 8866	0 0000	0 0000	3 0170	0 0000	0.0000	3.0170	1 8696	0 0000	0	1.9922	(0.1226)
over 1	11,146	9 5930	0 0000	0 0000	5 9158	0 0000	0 0000	5 9158	3.6772	0.0000	0	3.9140	(0 2368)
Winter 0-1	1,474	4 8866	0 0000	0 0000	3 0170	0 0000	0.0000	3.0170	1.8696	0.0000	0	1 9922	(0.1226)
over 1	19,698	8 4588	0 0000	0 0000	5.2059	0 0000	0.0000	5.2059	3.2529	0.0000	0	3.4521	(0.1992)
Energy Charges													
All Use-x night use	8,373,400	8 2050	1 1768	0 0000	0 3583	4.0623	1 0069	6 6043	1.6007	4 0623	340,153		1.6007
Night Use	42,782	7 0751	1 1768	0 0000	0.3583	4 0623	1.0069	6.6043	0.4708	4.0623	1,738		0.4708
Totals	8,416,182									5.44	457,916		
Monthly Minimum, MD													
Special Annual Minimum													
Special Provisions													
Standby	2 000	3 8600	0 0000	0 1800	2 8900	0 7800	0.0000	3 8500	0.0100	0 9600	2		
Area Dev Svc Cr Yrs 1-5	357	(2 8500)	0 0000	0 0000	(2 8500)	0 0000	0 0000	(2.8500)	0.0000	0 0000	0		
Area Dev Svc Cr Yrs 6&7													
Curt Elec Svc Cr													
Curt Elec Svc Peak Cr													
Police/Fire-Each													
Police/Fire-Minimum													
HS													
Energy Charges													
Summer	4,206	14 2258	1 1768	0 4217	5.7003	5 5159	1 0069	13.8216	0.4042	5.9376	250		
Winter	23,047	10 9897	1 1768	0.4217	4 3648	3.9490	1.0069	10.9192	0.0705	4.3707	1,007		
Totals	27,253									4.61	1,257		

2002a Unbundled Ra
Detail

		bill det. 2002 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
LPL-Secondary														
Service Charge		79 820	368 64	0 00	0 00	368 64	0.00	0.00	368.64	0	0	0		
Capacity Obligation		27,324	0 0000	0 0000	0 0000	0 0000	3 0917	0 0000	3 0917	(3.0917)	3.0917	84,478		
Transmission Obligation		22,992	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1.5961	(1.5961)	1.5961	36,698		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0.0000	0.0000	0		
Summer	On	9,014	8 7556	0 0000	0 0000	4 1045	0 0000	0.0000	4 1045	4 6511	0.0000	0	4 3809	0.2702
	Inter	6,609	1 1660	0 0000	0 0000	0 5336	0 0000	0.0000	0.5336	0.6324	0.0000	0	0.5827	0.0497
	Off	8,413	1 1660	0 0000	0 0000	0 5336	0 0000	0.0000	0 5336	0.6324	0.0000	0	0.5827	0.0497
Winter	On	15,297	7 6108	0 0000	0 0000	3 5710	0 0000	0.0000	3.5710	4.0398	0 0000	0	3.8070	0.2328
	Inter	11,523	1 1660	0 0000	0 0000	0 5336	0 0000	0.0000	0.5336	0.6324	0 0000	0	0.5827	0.0497
	Off	13,702	1 1660	0 0000	0 0000	0 5336	0 0000	0.0000	0.5336	0.6324	0.0000	0	0.5827	0.0497
Energy Charges														
	On	5,570,349	8 2886	1 1768	0 0000	0 2777	4.7815	1 0069	7 2429	1.0459	4.7815	266,346		1.0459
	Inter	744,848	7 2606	1 1768	0 0000	0 2777	4 1612	1 0069	6 6226	0.6380	4 1612	30,995		0.6380
	Off	4 325 488	5 6292	1 1768	0 0000	0 2777	2 5431	1 0069	5 0045	0 6247	2 5431	110,001		0.6247
Totals		10 640 685									4.97	528,518		
Special Annual Minimum														
LPL-Primary														
Service Charge		11 459	368 64	0 00	0 00	368 64	0 00	0 00	368 64	0	0	0		
		0 000	9 4800	0 0000	0 0000	9 4800	0 0000	0 0000	9 4800	0 0000	0 0000	0		
Capacity Obligation		10 044	0 0000	0 0000	0 0000	0 0000	3 0917	0 0000	3 0917	(3 0917)	3.0917	31,053		
Transmission Obligation		8 460	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1 5961	(1 5961)	1 5961	13,503		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0		
Summer	On	3 202	8 5648	0 0000	0 0000	3 1337	0 0000	0 0000	3 1337	5.4311	0 0000	0	4.4904	0.9407
	Inter	2 348	1 0494	0 0000	0 0000	0 3761	0 0000	0 0000	0.3761	0 6733	0 0000	0	0 5523	0.1210
	Off	2,988	1 0494	0 0000	0 0000	0 3761	0 0000	0 0000	0 3761	0 6733	0 0000	0	0 5523	0 1210
Winter	On	5,637	7 4306	0 0000	0 0000	2 7264	0 0000	0 0000	2.7264	4.7042	0.0000	0	3 8977	0.8065
	Inter	4,314	1 0494	0 0000	0 0000	0 3761	0 0000	0.0000	0 3761	0.6733	0.0000	0	0 5523	0.1210
	Off	5,208	1 0494	0 0000	0.0000	0.3761	0 0000	0.0000	0.3761	0.6733	0.0000	0	0.5523	0.1210
Energy Charges														
	On	2,105,732	7 5452	1 1222	0 0000	0 2661	4 5509	1.0069	6.9461	0.5991	4.5509	95,830		0.5991
	Inter	294,802	6 5689	1 1222	0 0000	0 2661	3 9662	1.0069	6.3614	0.2075	3.9662	11,692		0.2075
	Off	1,810,929	5 6096	1 1222	0 0000	0 2661	2.4345	1.0069	4.8297	0.7799	2.4345	44,087		0 7799
Totals		4,211,463									4.66	196,165		
Special Annual Minimum														
Special Provisions-LPL														
Standby-Sec.		29	3 8600	0 0000	0 1800	2 8300	0.8500	0.0000	3.8600	(0.0000)	1.0300	30		
Standby- Pri.		38	2.7300	0.0000	0 1800	1.6900	0 8700	0 0000	2.7400	(0.0100)	1.0500	40		
												70		
Area Dev Svc. Cr Yrs 1-5-Sec		1,158	(2 8500)	0 0000	0.0000	(2 8500)	0 0000	0.0000	(2 8500)	0 0000	0 0000	0		
Area Dev. Svc. Cr Yrs 1-5-Pri.		300	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0 0000	0 0000	0 0000	0		
Curt Elec Svc Cr														
Curt Elec Svc Peak Cr														
IES Cr 2 Hr. Ntc.-Sec.		36	(3 2900)	0 0000	0 0000	0 0000	(3 2900)	0 0000	(3 2900)	0 0000	(3 2900)	(118)		
IES Cr 30 Min Ntc.-Sec		99	(4 5300)	0 0000	0 0000	0 0000	(4 5300)	0 0000	(4 5300)	0 0000	(4 5300)	(448)		
IES Cr. 2 Hr. Ntc.-Pri.		0	(3 2900)	0 0000	0 0000	0 0000	(3 2900)	0 0000	(3 2900)	0 0000	(3 2900)	0		
IES Cr. 30 Min Ntc.-Pri.		75	(4.5300)	0 0000	0 0000	0.0000	(4 5300)	0.0000	(4 5300)	0 0000	(4 5300)	(340)		
IES Chg 2 Hr. Ntc.												(906)		
IES Chg 30 Min Ntc.														

2002a Unbundled Rat.
Detail

	bill det. 2002 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
HTS-Subtrans													
Service Charge	2 214	2,026 07	0 00	0 00	2,026 07	0.00	0.00	2,026.07	0	0	0		
Capacity Obligation	7,915	0 0000	0 0000	0 0000	0 0000	3 0917	0 0000	3.0917	(3.0917)	3 0917	24,471		
Transmission Obligation	6,668	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1.5961	(1 5961)	1.5961	10,643		
Demand Charges		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0		
Summer On	2,817	10 4834	0 0000	0 0000	1 3031	0 0000	0 0000	1.3031	9.1803	0.0000	0	4.5234	4.6569
Inter		0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0.0000	0.0000	0.0000	0	0.0000	0.0000
Off		0.0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0.0000	0	0.0000	0.0000
Winter On	5,417	9 5718	0 0000	0 0000	1 1858	0.0000	0.0000	1.1858	8.3860	0.0000	0	4.1299	4.2561
Inter		0 0000	0 0000	0 0000	0.0000	0 0000	0 0000	0 0000	0.0000	0.0000	0	0.0000	0.0000
Off		0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0.0000	0	0.0000	0.0000
Energy Charges													
On	1,563,654	6 8074	1 1060	0 0000	0 1940	4 4293	1.0069	6 7362	0.0712	4.4293	69,259		0.0712
Inter	279,146	5 8365	1 1060	0 0000	0 1940	3 8565	1 0069	6.1634	(0 3269)	3 8565	10,765		(0.3269)
Off	1,595,800	5 0616	1 1060	0 0000	0 1940	2 3518	1 0069	4.6587	0.4029	2.3518	37,530		0.4029
Totals	3,438,600									**4.44**	152,668		
Special Annual Minimum													
HTS-High Voltage													
Service Charge	0 170	1 823 47	0 00	0 00	1,823 47	0 00	0.00	1,823.47	0	0	0		
Capacity Obligation	689	0 0000	0 0000	0 0000	0 0000	3 0917	0 0000	3 0917	(3.0917)	3.0917	2,130		
Transmission Obligation	580	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1.5961	(1.5961)	1.5961	926		
Demand Charges		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0		
Summer On	324	9 4351	0 0000	0 0000	1 1728	0 0000	0 0000	1.1728	8 2623	0.0000	0	3.4372	4.8251
Inter		0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0 0000	0.0000	0	0 0000	0.0000
Off		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0	0.0000	0 0000
Winter On	619	8 6146	0 0000	0 0000	1 0686	0 0000	0.0000	1.0686	7.5460	0 0000	0	3.1382	4 4078
Inter		0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0 0000	0	0.0000	0.0000
Off		0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0.0000	0.0000	0	0.0000	0.0000
Energy Charges													
On	190,028	6 0555	1 0796	0 0000	0 1940	4 3286	1.0069	6 6091	(0.5536)	4 3286	8,226		(0.5536)
Inter	25,842	5 1816	1.0796	0.0000	0.1940	3.7694	1 0069	6.0499	(0.8683)	3.7694	974		(0.8683)
Off	157,882	4 4842	1.0796	0 0000	0.1940	2 3013	1.0069	4.5818	(0.0976)	2.3013	3,633		(0.0976)
Totals	373,752									**4.25**	15,889		
Special Annual Minimum													
Special Provisions-HTS													
Standby- Subtrans.	410	1 3900	0.0000	0 1700	0 3200	0.9000	0.0000	1 3900	0 0000	1.0700	439		
Standby- High Voltage	208	1 2500	0.0000	0.1500	0.2900	0.8200	0.0000	1.2600	(0.0100)	0.9700	202		
											641		
Area Dev. Svc. Cr. Yrs 1-5-Sub	70	(1.9000)	0 0000	0 0000	(1.9000)	0 0000	0.0000	(1 9000)	0.0000	0 0000	0		
Area Dev. Svc. Cr. Yrs 1-5-HV	49	0 0000	0.0000	0.0000	0 0000	0.0000	0 0000	0 0000	0 0000	0 0000	0		
Curt Elec Svc. Cr													
Curt. Elec. Svc. Peak Cr													
IES Cr. 2 Hr. Ntc.-Sub	312	(3 2900)	0 0000	0 0000	0 0000	(3 2900)	0 0000	(3.2900)	0 0000	(3 2900)	(1,026)		
IES Cr. 30 Min Ntc.-Sub	319	(4.5300)	0 0000	0 0000	0 0000	(4 5300)	0.0000	(4 5300)	0 0000	(4 5300)	(1,445)		
IES Cr. 2 Hr. Ntc.-HV	0	(3 2900)	0.0000	0 0000	0 0000	(3 2900)	0.0000	(3 2900)	0 0000	(3 2900)	0		
IES Cr. 30 Min Ntc.-HV	779	(4.5300)	0 0000	0.0000	0.0000	(4.5300)	0 0000	(4.5300)	0 0000	(4 5300)	(3,529)		
IES Chg. 2 Hr. Ntc.											(6,000)		
IES Chg. 30 Min Ntc.													

2002a Unbundled Rat
Detail

	bill det. 2002 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7.	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
BPL	317,218	17 3316	1 1768	0 0000	10 7704	2 9142	1 0069	15 8683	1.4633	2.9142	9,244		
	317,218									2.91	9,244		
PSAL	159,749	21 8335	1 1768	0 0000	13 3919	2 9142	1.0069	18.4898	3.3437	2.9142	4,655		
	159,749									2.91	4,655		

2002b Unbundled Rat
Detail

		bill det. 2002 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
RS														
Service Charge		20,832 180	2 41	0 00	0 00	2 41	0 00	0.00	2.41	0.00	0.00	0		
Energy Charges														
	0-600	8,488,719	11 6967	1 1768	0 6550	3 3317	5 1540	1 0069	11.3244	0.3723	5.8090	493,110		
	Over 600 Sum	1,541,636	13 1595	1 1768	0 6550	3 7368	6 0712	1 0069	12.6467	0.5128	6.7262	103,694		
	Over 600 Win	1,208,515	11 1179	1 1768	0 6550	3 1581	4 4935	1.0069	10 4903	0.6276	5.1485	62,220		
Totals		11,238,870									**5.86**	659,024		
RHS														
Service Charge		0 000												
Energy Charges														
	0-600	0												
	Over 600 Sum	0												
	Over 600 Win	0												
	Common	0												
Totals		0												
RLM														
Service Charge		58 585	12 12	0 00	0 00	12 12	0 00	0 00	12 12	0 00	0 00	0		
Service Charge over 20,000		118 944	6 79	0 00	0 00	6 79	0 00	0 00	6 79	0.00	0.00	0		
Service Charge Sp. Prv. (I)														
Energy Charges														
Summer	On	58 498	17 6761	1 1768	0 5451	3 8067	7 6338	1 0069	14 1693	3 5068	8 1789	4,784		
	Inter	10 968	16 1519	1 1768	0 5451	3 2810	6 5359	1 0069	12 5457	3 6062	7 0810	777		
	Off	52,405	6 3532	1 1768	0 5451	1 2484	3 8563	1.0069	7.8335	(1.4803)	4 4014	2,307		
Winter	On	77,793	12 0878	1 1768	0 5451	2 6502	4 8761	1 0069	10 2551	1 8327	5 4212	4,217		
	Inter	15,912	12 3072	1 1768	0 5451	2 5100	4 5415	1 0069	9 7803	2.5269	5.0866	809		
	Off	83,097	6 3532	1 1768	0 5451	1 2484	3 5290	1 0069	7.5062	(1.1530)	4 0741	3,385		
Totals		298,673									**5.45**	16,279		
WH														
Energy Charge		7,194	10 2021	1 1768	0 0000	5.3229	2 5370	1.0069	10,0436	0.1585	2.5370	183		
Totals		7,194									**2.54**	183		
WHS														
Service Charge		0.960	2 82	0.00	0.00	2.82	0.00	0.00	2.82	0.00	0.00	0 000		
Energy Charge		166	5.4596	1 1768	0.0000	1.5648	2.5394	1.0069	6.2879	(0.8283)	2.5394	4 215		
Totals		166									**2.54**	4.215		

STC, preliminary values, adjusted at least annually.

2002b Unbundled Rate
Detail

	bill det. 2002 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
GLP													
Service Charge	2,881 491	4 04	0 00	0 00	4 04	0 00	0 00	4 04	0	0	0		
Service Charge- Night Use	0 984	367 08	0 00	0 00	367 08	0.00	0.00	367.08	0	0	0		
Capacity Obligation	26,160	0 0000	0 0000	0 0000	0 0000	3 0917	0.0000	3 0917	(3 0917)	3.0917	80,879		
Transmission Obligation	22,020	0 0000	0 0000	1 5961	0 0000	0 0000	0.0000	1.5961	(1.5961)	1.5961	35,146		
Demand Charges		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0		
Summer 0-1	734	4 8866	0 0000	0.0000	3 0170	0 0000	0 0000	3.0170	1.8696	0.0000	0	1.9922	(0.1226)
over 1	11,146	9 5930	0 0000	0.0000	5 9158	0 0000	0 0000	5.9158	3.6772	0.0000	0	3.9140	(0.2368)
Winter 0-1	1,474	4 8866	0.0000	0 0000	3.0170	0 0000	0 0000	3.0170	1.8696	0.0000	0	1.9922	(0.1226)
over 1	19,698	8 4588	0 0000	0 0000	5 2059	0 0000	0 0000	5.2059	3.2529	0.0000	0	3.4521	(0.1992)
Energy Charges													
All Use-x night use	8,373,400	8 2580	1 1768	0 0000	0 4113	4 0623	1.0069	6.6573	1.6007	4 0623	340,153		1.6007
Night Use	42,782	7 1281	1 1768	0.0000	0 4113	4 0623	1.0069	6.6573	0.4708	4.0623	1,738		0.4708
Totals	8,416,182									5.44	457,916		
Monthly Minimum, MD													
Special Annual Minimum													
Special Provisions													
Standby	2 000	3 8600	0 0000	0 1800	2 8900	0 7800	0.0000	3 8500	0.0100	0.9600	2		
Area Dev Svc Cr Yrs 1-5	357	(2 8500)	0 0000	0 0000	(2 8500)	0 0000	0.0000	(2.8500)	0.0000	0.0000	0		
Area Dev Svc Cr. Yrs 6&7													
Curt Elec Svc Cr													
Curt. Elec. Svc Peak Cr													
Police/Fire-Each													
Police/Fire-Minimum													
HS													
Energy Charges													
Summer	4,206	14 2788	1 1768	0 4217	5.7533	5.5159	1.0069	13.8746	0.4042	5 9376	250		
Winter	23,047	11.0427	1.1768	0.4217	4.4178	3.9490	1.0069	10.9722	0.0705	4.3707	1,007		
Totals	27,253									4.61	1,257		

ATTACHMENT 2

2002b Unbundled Ra
Detail

		bill det. 2002 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
LPL-Secondary														
Service Charge		79 620	368 64	0 00	0 00	368 64	0 00	0.00	368.64	0	0	0		
Capacity Obligation		27.324	0 0000	0 0000	0 0000	0 0000	3 0917	0 0000	3 0917	(3 0917)	3.0917	84,478		
Transmission Obligation		22,992	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1 5961	(1.5961)	1 5961	36,698		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0		
Summer	On	9,014	8 7556	0 0000	0 0000	4 1045	0 0000	0.0000	4 1045	4 6511	0.0000	0	4 3809	0.2702
	Inter	6,609	1 1660	0 0000	0 0000	0 5336	0 0000	0 0000	0 5336	0 6324	0.0000	0	0.5827	0.0497
	Off	8,413	1 1660	0 0000	0 0000	0 5336	0 0000	0 0000	0 5336	0.6324	0.0000	0	0.5827	0.0497
Winter	On	15,297	7 6108	0 0000	0 0000	3 5710	0 0000	0.0000	3.5710	4.0398	0.0000	0	3.8070	0.2328
	Inter	11,523	1 1660	0 0000	0 0000	0 5336	0 0000	0.0000	0 5336	0.6324	0 0000	0	0 5827	0.0497
	Off	13,702	1 1660	0 0000	0 0000	0 5336	0.0000	0.0000	0.5336	0.6324	0.0000	0	0.5827	0.0497
Energy Charges														
	On	5,570,349	8 3301	1 1768	0 0000	0 3191	4 7815	1.0069	7 2843	1.0458	4.7815	266,346		1.0458
	Inter	744,848	7 3019	1 1768	0 0000	0 3191	4 1612	1 0069	6.6640	0.6379	4.1612	30,995		0.6379
	Off	4 325 488	5 6706	1 1768	0 0000	0 3191	2 5431	1 0069	5.0459	0.6247	2.5431	110,001		0.6247
Totals		10,640,685									4.97	528,518		
Special Annual Minimum														
LPL-Primary														
Service Charge		11 459	368 64	0 00	0 00	368 64	0 00	0.00	368.64	0	0	0		
		0 000	9 4800	0 0000	0 0000	9 4800	0 0000	0 0000	9 4800	0.0000	0 0000	0		
Capacity Obligation		10.044	0 0000	0 0000	0 0000	0 0000	3 0917	0 0000	3 0917	(3.0917)	3 0917	31,053		
Transmission Obligation		8,460	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1.5961	(1.5961)	1 5961	13,503		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0.0000	0		
Summer	On	3,202	8 5648	0 0000	0 0000	3 1337	0 0000	0 0000	3 1337	5.4311	0.0000	0	4.4904	0.9407
	Inter	2,348	1 0494	0 0000	0 0000	0 3761	0 0000	0 0000	0 3761	0 6733	0.0000	0	0 5523	0.1210
	Off	2,988	1 0494	0 0000	0 0000	0 3761	0 0000	0.0000	0 3761	0.6733	0.0000	0	0 5523	0.1210
Winter	On	5,637	7 4306	0 0000	0 0000	2 7264	0 0000	0 0000	2.7264	4.7042	0.0000	0	3 8977	0.8065
	Inter	4,314	1 0494	0 0000	0 0000	0 3761	0 0000	0 0000	0 3761	0 6733	0.0000	0	0 5523	0.1210
	Off	5,208	1 0494	0 0000	0.0000	0 3761	0.0000	0.0000	0.3761	0.6733	0.0000	0	0.5523	0.1210
Energy Charges														
	On	2,105,732	7 5844	1 1222	0 0000	0 3053	4 5509	1.0069	6.9853	0 5991	4.5509	95,830		0.5991
	Inter	294,802	6 6081	1 1222	0 0000	0 3053	3 9662	1.0069	6 4006	0 2075	3.9662	11,692		0 2075
	Off	1,810,929	5 6488	1 1222	0 0000	0 3053	2.4345	1.0069	4.8689	0.7799	2.4345	44,087		0.7799
Totals		4,211,463									4.66	196,165		
Special Annual Minimum														
Special Provisions-LPL														
Standby-Sec.		29	3 8600	0 0000	0 1800	2 8300	0 8500	0 0000	3.8600	(0 0000)	1.0300	30		
Standby- Pri.		38	2 7300	0.0000	0.1800	1 6900	0.8700	0.0000	2.7400	(0.0100)	1 0500	40		
												70		
Area Dev. Svc. Cr Yrs 1-5-Sec		1,158	(2 8500)	0 0000	0 0000	(2.8500)	0.0000	0.0000	(2.8500)	0 0000	0.0000	0		
Area Dev Svc. Cr Yrs 1-5-Pri		300	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0		
Curt. Elec. Svc. Cr														
Curt. Elec. Svc. Peak Cr														
IES Cr 2 Hr. Nlc -Sec.		36	(3 2900)	0 0000	0 0000	0.0000	(3 2900)	0 0000	(3 2900)	0 0000	(3 2900)	(118)		
IES Cr. 30 Min Nlc.-Sec.		99	(4 5300)	0.0000	0 0000	0 0000	(4 5300)	0 0000	(4.5300)	0 0000	(4 5300)	(448)		
IES Cr 2 Hr. Nlc.-Pri.		0	(3 2900)	0 0000	0 0000	0.0000	(3 2900)	0.0000	(3 2900)	0.0000	(3 2900)	0		
IES Cr. 30 Min Nlc.-Pri.		75	(4.5300)	0 0000	0.0000	0.0000	(4 5300)	0.0000	(4 5300)	0,0000	(4 5300)	(340)		
IES Chg. 2 Hr. Nlc.												(906)		
IES Chg 30 Min Nlc														

2002b Unbundled Rate
Detail

		bill det. 2002 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
HTS-Subtrans														
Service Charge		2 214	2,026 07	0 00	0 00	2,026 07	0.00	0.00	2,026.07	0	0	0		
Capacity Obligation		7,915	0 0000	0 0000	0 0000	0 0000	3 0917	0 0000	3 0917	(3 0917)	3 0917	24,471		
Transmission Obligation		6,668	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1 5961	(1 5961)	1.5961	10,643		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0.0000	0.0000	0		
Summer	On	2,817	10 4834	0 0000	0 0000	1 3031	0 0000	0.0000	1.3031	9.1803	0.0000	0	4.5234	4.6569
	Inter		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0	0.0000	0.0000
	Off		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0	0 0000	0.0000
Winter	On	5,417	9 5718	0 0000	0 0000	1 1858	0 0000	0 0000	1.1858	8 3860	0.0000	0	4 1299	4.2561
	Inter		0 0000	0 0000	0 0000	0.0000	0 0000	0.0000	0 0000	0.0000	0 0000	0	0.0000	0.0000
	Off		0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0 0000	0.0000	0	0.0000	0.0000
Energy Charges														
	On	1 563 654	6 8360	1 1060	0 0000	0 2226	4 4293	1 0069	6 7648	0 0712	4 4293	69,259		0.0712
	Inter	279 146	5 8651	1 1060	0 0000	0 2226	3 8565	1 0069	6 1920	(0 3269)	3.8565	10,765		(0.3269)
	Off	1 595 800	5 0902	1 1060	0 0000	0 2226	2 3518	1 0069	4 6873	0 4029	2 3518	37,530		0.4029
Totals		3,438,600									4.44	152,668		
Special Annual Minimum														
HTS-High Voltage														
Service Charge		0 170	1 823 47	0 00	0 00	1 823 47	0 00	0 00	1,823.47	0	0	0		
Capacity Obligation		689	0 0000	0 0000	0 0000	0 0000	3 0917	0 0000	3 0917	(3 0917)	3 0917	2,130		
Transmission Obligation		580	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1 5961	(1 5961)	1 5961	926		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0		
Summer	On	324	9 4351	0 0000	0 0000	1 1728	0 0000	0 0000	1 1728	8 2623	0 0000	0	3.4372	4 8251
	Inter		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0	0.0000	0.0000
	Off		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0	0 0000	0.0000
Winter	On	619	8 6146	0 0000	0 0000	1 0686	0 0000	0 0000	1 0686	7 5460	0.0000	0	3.1382	4 4078
	Inter		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0	0 0000	0.0000
	Off		0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0.0000	0.0000	0	0.0000	0.0000
Energy Charges														
	On	190,028	6 0812	1 0796	0 0000	0 2226	4 3286	1 0069	6.6377	(0 5565)	4.3286	8,226		(0.5565)
	Inter	25,842	5 2078	1 0796	0 0000	0 2226	3 7694	1.0069	6.0785	(0 8707)	3.7694	974		(0 8707)
	Off	157,882	4 5103	1 0796	0 0000	0.2226	2 3013	1.0069	4.6104	(0.1001)	2.3013	3,633		(0.1001)
Totals		373,752									4.25	15,889		
Special Annual Minimum														
Special Provisions-HTS														
Standby- Subtrans.		410	1.3900	0 0000	0 1700	0 3200	0 9000	0.0000	1 3900	0.0000	1 0700	439		
Standby- High Voltage		208	1.2500	0.0000	0 1500	0 2900	0 8200	0.0000	1.2600	(0.0100)	0.9700	202		
												641		
Area Dev. Svc. Cr Yrs 1-5-Sub		70	(1 9000)	0 0000	0 0000	(1 9000)	0 0000	0 0000	(1 9000)	0 0000	0.0000	0		
Area Dev Svc Cr Yrs 1-5-HV		49	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0 0000	0 0000	0		
Curt Elec Svc Cr														
Curt. Elec. Svc Peak Cr														
IES Cr. 2 Hr. Ntc.-Sub		312	(3 2900)	0 0000	0 0000	0 0000	(3 2900)	0 0000	(3 2900)	0 0000	(3 2900)	(1,026)		
IES Cr 30 Min Ntc -Sub		319	(4 5300)	0 0000	0.0000	0 0000	(4 5300)	0 0000	(4 5300)	0 0000	(4 5300)	(1,445)		
IES Cr. 2 Hr. Ntc.-HV		0	(3 2900)	0 0000	0.0000	0 0000	(3 2900)	0 0000	(3 2900)	0 0000	(3 2900)	0		
IES Cr. 30 Min Ntc -HV		779	(4 5300)	0 0000	0 0000	0 0000	(4.5300)	0 0000	(4 5300)	0 0000	(4 5300)	(3,529)		
IES Chg 2 Hr. Ntc.												(6,000)		
IES Chg 30 Min Ntc.														

2002b Unbundled Rat[illegible]
Detail

	bill det. 2002 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
BPL	317,218	17 3645	1 1768	0 0000	10 8033	2 9142	1 0069	15.9012	1.4633	2.9142	9,244		
	317,218									**2.91**	9,244		
PSAL	159,749	21 8663	1 1768	0 0000	13 4248	2 9142	1 0069	18.5227	3 3436	2.9142	4,655		
	159,749									**2.91**	4,655		

2003 Unbundled Rat[illegible]
Detail

			bill det. 2003 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
RS															
	Service Charge		20,965 236	2 41	0 00	0 00	2 41	0 00	0 00	2 41	0.00	0.00	0		
	Energy Charges														
		0-600	8,605,337	11 6967	1 1768	0 6533	3 3317	5 1524	0 9969	11 3111	0.3856	5.8057	499,600		
		Over 600 Sum	1,562,815	13 1595	1 1768	0 6533	3 7368	6 0600	0 9969	12 6238	0.5357	6.7133	104,916		
		Over 600 Win	1,225,118	11 1179	1 1768	0 6533	3 1581	4 4989	0.9969	10.4840	0 6339	5.1522	63,121		
	Totals		11,393,270									5.86	667,637		
RHS															
	Service Charge		0 000												
	Energy Charges														
		0-600	0												
		Over 600 Sum	0												
		Over 600 Win	0												
		Common	0												
	Totals		0												
RLM															
	Service Charge		58 236	12 12	0 00	0 00	12 12	0 00	0 00	12 12	0 00	0 00	0		
	Service Charge over 20,000		118 236	6 79	0 00	0 00	6 79	0 00	0 00	6 79	0 00	0.00	0		
	Service Charge Sp. Prv. (I)														
	Energy Charges														
	Summer	On	57,547	17 6761	1 1768	0 5410	3 8067	7 5954	0 9969	14 1168	3 5593	8.1364	4,682		
		Inter	10,790	16 1519	1 1768	0 5410	3 2810	6 5090	0 9969	12 5047	3 6472	7.0500	761		
		Off	51,553	6 3532	1 1768	0 5410	1 2484	3 8574	0 9969	7 8205	(1 4673)	4.3984	2,268		
	Winter	On	76,528	12 0878	1 1768	0 5410	2 6502	4 8665	0 9969	10 2314	1.8564	5.4075	4,138		
		Inter	15,653	12 3072	1 1768	0 5410	2 5100	4 5354	0 9969	9.7601	2.5471	5.0764	795		
		Off	81,746	6 3532	1 1768	0 5410	1 2464	3 5335	0 9969	7.4966	(1.1434)	4.0745	3,331		
	Totals		293,817									5.44	15,975		
WH															
	Energy Charge		5,947	10 2021	1 1768	0 0000	5.3229	2 5075	0.9969	10.0041	0.1980	2.5075	149		
	Totals		5,947									2.51	149		
WHS															
	Service Charge		0 851	2.82	0.00	0 00	2.82	0.00	0.00	2.82	0.00	0.00	0 000		
	Energy Charge		143	5 4596	1 1768	0 0000	1.5648	2 5099	0.9969	6.2484	(0.7888)	2 5099	3 589		
	Totals		143									2.51	3.589		

STC, preliminary values, adjusted at least annually.

2003 Unbundled Rate.
Detail

		bill det. 2003 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
GLP														
Service Charge		2,900 104	4 04	0 00	0 00	4 04	0 00	0 00	4 04	0	0	0		
Service Charge- Night Use		0 864	367 08	0 00	0 00	367 08	0.00	0.00	367.08	0	0	0		
Capacity Obligation		26,484	0 0000	0 0000	0 0000	0 0000	3 1800	0 0000	3 1800	(3 1800)	3.1800	84,219		
Transmission Obligation		22,296	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1 5961	(1 5961)	1.5961	35,587		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0		
Summer	0-1	744	4 8866	0 0000	0 0000	3 0170	0 0000	0.0000	3.0170	1.8696	0.0000	0	2 0286	(0 1590)
	over 1	11,302	9 5930	0 0000	0 0000	5 9158	0 0000	0 0000	5.9158	3.6772	0.0000	0	3.9855	(0.3083)
Winter	0-1	1,495	4 8866	0 0000	0 0000	3 0170	0 0000	0 0000	3.0170	1.8696	0.0000	0	2.0286	(0.1590)
	over 1	19,976	8 4588	0 0000	0 0000	5 2059	0.0000	0.0000	5.2059	3.2529	0.0000	0	3.5152	(0.2623)
Energy Charges														
	All Use-x night use	8,496,541	8 2580	1 1768	0 0000	0 4113	4 0319	0 9969	6 6169	1.6411	4.0319	342,572		1.6411
	Night Use	37,060	7 1281	1 1768	0 0000	0 4113	4 0319	0 9969	6 6169	0 5112	4 0319	1,494		0.5112
Totals		8 533 601									5.44	463,872		
Monthly Minimum, MD														
Special Annual Minimum														
Special Provisions														
Standby		2 000	3 8600	0 0000	0 1800	2 8900	0 7800	0 0000	3 8500	0 0100	0.9600	2		
Area Dev Svc Cr Yrs 1-5		357	(2 8500)	0 0000	0 0000	(2 8500)	0 0000	0 0000	(2 8500)	0 0000	0 0000	0		
Area Dev Svc Cr Yrs 6&7														
Curt Elec Svc Cr														
Curt Elec Svc Peak Cr														
Police/Fire-Each														
Police/Fire-Minimum														
HS														
Energy Charges														
	Summer	4,047	14 2788	1 1768	0 3652	5 7533	5 4005	0.9969	13.6927	0.5861	5 7657	233		
	Winter	22,176	11.0427	1 1768	0.3652	4 4178	3 8499	0.9969	10.8066	0 2361	4.2151	935		
Totals		26,223									4.45	1,168		

2003 Unbundled Rat.
Detail

	bill det. 2003 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
LPL-Secondary													
Service Charge	80 638	368 64	0 00	0 00	368 64	0.00	0.00	368.64	0	0	0		
Capacity Obligation	27,660	0 0000	0 0000	0 0000	0 0000	3 1800	0 0000	3 1800	(3.1800)	3.1800	87,959		
Transmission Obligation	23,280	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1 5961	(1 5961)	1 5961	37,157		
Demand Charges		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0		
Summer On	9,146	8 7556	0 0000	0·0000	4 1045	0 0000	0 0000	4 1045	4 6511	0.0000	0	4.4603	0.1908
Inter	6,706	1 1660	0 0000	0 0000	0 5336	0 0000	0 0000	0.5336	0.6324	0 0000	0	0 5932	0 0392
Off	8,536	1 1660	0 0000	0 0000	0 5336	0 0000	0 0000	0 5336	0 6324	0.0000	0	0.5932	0.0392
Winter On	15,508	7 6108	0 0000	0 0000	3 5710	0 0000	0 0000	3.5710	4.0398	0.0000	0	3.8760	0.1638
Inter	11,682	1 1660	0 0000	0 0000	0 5336	0 0000	0 0000	0.5336	0.6324	0.0000	0	0.5932	0 0392
Off	13,891	1 1660	0 0000	0.0000	0 5336	0.0000	0 0000	0.5336	0.6324	0.0000	0	0.5932	0.0392
Energy Charges													
On	5,653,467	8 3301	1 1768	0 0000	0 3191	4 7546	0.9969	7.2474	1,0827	4.7546	268,800		1.0827
Inter	755,962	7 3019	1 1768	0 0000	0 3191	4 1408	0 9969	6.6336	0.6683	4.1408	31,303		0.6683
Off	4,390,031	5 6706	1 1768	0 0000	0 3191	2 5395	0 9969	5 0323	0.6383	2.5395	111,485		0.6383
Totals	10,799,460									4.97	536,704		
Special Annual Minimum													
LPL-Primary													
Service Charge	11 544	368 64	0 00	0 00	368 64	0 00	0 00	368.64	0	0	0		
	0 000	9 4800	0 0000	0 0000	9 4800	0 0000	0 0000	9 4800	0.0000	0 0000	0		
Capacity Obligation	10,116	0 0000	0 0000	0 0000	0 0000	3 1800	0 0000	3.1800	(3.1800)	3 1800	32,169		
Transmission Obligation	8,520	0 0000	0 0000	1 5961	0 0000	0 0000	0.0000	1 5961	(1 5961)	1.5961	13,599		
Demand Charges		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0		
Summer On	3,233	8 5648	0 0000	0 0000	3 1337	0 0000	0 0000	3 1337	5.4311	0.0000	0	4 5701	0.8610
Inter	2,370	1 0494	0 0000	0 0000	0 3761	0 0000	0 0000	0 3761	0 6733	0.0000	0	0 5621	0.1112
Off	3,017	1 0494	0 0000	0 0000	0 3761	0 0000	0 0000	0 3761	0.6733	0.0000	0	0 5621	0.1112
Winter On	5,688	7 4306	0 0000	0 0000	2.7264	0 0000	0.0000	2 7264	4.7042	0.0000	0	3.9668	0.7374
Inter	4,354	1 0494	0 0000	0 0000	0 3761	0 0000	0 0000	0.3761	0 6733	0 0000	0	0 5621	0 1112
Off	5,255	1 0494	0 0000	0 0000	. 0.3761	0 0000	0.0000	0.3761	0 6733	0.0000	0	0.5621	0.1112
Energy Charges													
On	2,126,097	7 5844	1 1222	0 0000	0 3053	4.5259	0 9969	6 9503	0.6341	4 5259	96,225		0 6341
Inter	297,654	6 6081	1 1222	0.0000	0 3053	3.9473	0 9969	6.3717	0 2364	3 9473	11,749		0 2364
Off	1,828,443	5 6488	1 1222	0.0000	0 3053	2.4316	0 9969	4.8560	0.7928	2.4316	44,460		0.7928
Totals	4,252,194									4.66	198,202		
Special Annual Minimum													
Special Provisions-LPL													
Standby-Sec.	29	3.8600	0 0000	0.1800	2.8300	0 8500	0 0000	3.8600	(0 0000)	1 0300	30		
Standby- Pri.	38	2.7300	0 0000	0.1800	1.6900	0.8700	0.0000	2 7400	(0.0100)	1.0500	40		
											70		
Area Dev. Svc. Cr. Yrs 1-5-Sec.	1,158	(2 8500)	0.0000	0 0000	(2 8500)	0.0000	0.0000	(2 8500)	0 0000	0.0000	0		
Area Dev. Svc. Cr. Yrs 1-5-Pri	300	0 0000	0.0000	0.0000	0 0000	0.0000	0.0000	0 0000	0.0000	0 0000	0		
Curl Elec Svc Cr													
Curt Elec. Svc Peak Cr													
IES Cr 2 Hr. Ntc.-Sec.	36	(3 2900)	0 0000	0 0000	0 0000	(3 2900)	0 0000	(3 2900)	0 0000	(3 2900)	(118)		
IES Cr. 30 Min Ntc.-Sec.	99	(4.5300)	0 0000	0.0000	0 0000	(4.5300)	0 0000	(4 5300)	0 0000	(4 5300)	(448)		
IES Cr 2 Hr. Ntc.-Pri.	0	(3 2900)	0 0000	0 0000	0 0000	(3 2900)	0 0000	(3 2900)	0 0000	(3 2900)	0		
IES Cr. 30 Min Ntc.-Pri.	75	(4 5300)	0 0000	0.0000	0.0000	(4.5300)	0.0000	(4 5300)	0 0000	(4 5300)	(340)		
IES Chg 2 Hr. Ntc.											(906)		
IES Chg. 30 Min Ntc.													

2003 Unbundled Rat
Detail

		bill det. 2003 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig.Adj. (12)	Adj MTC (13)
HTS-Subtrans														
Service Charge		2 225	2,026 07	0 00	0 00	2,026 07	0.00	0.00	2,026.07	0	0	0		
Capacity Obligation		7,762	0 0000	0 0000	0 0000	0 0000	3 1800	0 0000	3.1800	(3.1800)	3 1800	24,683		
Transmission Obligation		6,535	0 0000	0 0000	1 5961	0 0000	0 0000	0 0000	1 5961	(1.5961)	1 5961	10,431		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0		
Summer	On	2,784	10 4834	0 0000	0 0000	1 3031	0 0000	0 0000	1 3031	9 1803	0.0000	0	4 5773	4 6030
	Inter		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0 0000	0	0 0000	0.0000
	Off		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0	0 0000	0.0000
Winter	On	5,353	9 5718	0 0000	0 0000	1.1858	0.0000	0.0000	1.1858	8.3860	0.0000	0	4.1791	4.2069
	Inter		0 0000	0 0000	0 0000	0 0000	0 0000	0,0000	0.0000	0.0000	0.0000	0	0.0000	0.0000
	Off		0 0000	0 0000	0.0000	0.0000	0 0000	0.0000	0.0000	0.0000	0.0000	0	0.0000	0.0000
Energy Charges														
	On	1,536,391	6 8360	1 1060	0 0000	0 2226	4 4012	0 9969	6.7267	0.1093	4 4012	67,620		0 1093
	Inter	274 279	5 8651	1 1060	0 0000	0 2226	3 8344	0 9969	6 1599	(0 2948)	3 8344	10,517		(0 2948)
	Off	1,567 977	5 0902	1 1060	0 0000	0 2226	2'3454	0 9969	4 6709	0,4193	2 3454	36,775		0.4193
Totals		3,378,647									4.44	150,026		
Special Annual Minimum														
HTS-High Voltage														
Service Charge		0 171	1 823 47	0 00	0 00	1,823 47	0 00	0.00	1,823.47	0	0	0		
Capacity Obligation		674	0 0000	0 0000	0 0000	0 0000	3 1800	0 0000	3.1800	(3 1800)	3.1800	2,143		
Transmission Obligation		569	0 0000	0 0000	1 5961	0 0000	0 0000	0.0000	1.5961	(1 5961)	1 5961	908		
Demand Charges			0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0 0000	0		
Summer	On	321	9 4351	0 0000	0 0000	1 1728	0 0000	0 0000	1 1728	8.2623	0 0000	0	3 4718	4.7905
	Inter		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0.0000	0	0.0000	0 0000
	Off		0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0 0000	0 0000	0	0.0000	0 0000
Winter	On	611	8 6146	0 0000	0 0000	1 0686	0 0000	0 0000	1.0686	7 5460	0 0000	0	3 1698	4 3762
	Inter		0 0000	0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0.0000	0.0000	0	0.0000	0.0000
	Off		0 0000	0 0000	0 0000	0 0000	0 0000	0.0000	0 0000	0,0000	0.0000	0	0.0000	0.0000
Energy Charges														
	On	186,715	6 0812	1 0796	0 0000	0 2226	4 3013	0 9969	6.6004	(0 5192)	4.3013	8,031		(0 5192)
	Inter	25,391	5 2078	1 0796	0 0000	0 2226	3 7480	0.9969	6.0471	(0 6393)	3 7480	952		(0 6393)
	Off	155,129	4 5103	1 0796	0 0000	0 2226	2 2951	0.9969	4 5942	(0 0839)	2.2951	3,560		(0 0839)
Totals		367,235									4.25	15,594		
Special Annual Minimum														
Special Provisions-HTS														
Standby- Subtrans.		410	1 3900	0 0000	0 1700	0 3200	0.9000	0.0000	1 3900	0.0000	1 0700	439		
Standby- High Voltage		208	1.2500	0 0000	0.1500	0 2900	0.8200	0.0000	1.2600	(0.0100)	0 9700	202		
												641		
Area Dev. Svc Cr. Yrs 1-5-Sub		70	(1 9000)	0 0000	0 0000	(1 9000)	0 0000	0 0000	(1 9000)	0 0000	0 0000	0		
Area Dev. Svc Cr Yrs 1-5-HV		49	0 0000	0 0000	0.0000	0 0000	0 0000	0.0000	0 0000	0 0000	0 0000	0		
Curt. Elec Svc Cr														
Curt Elec. Svc. Peak Cr														
IES Cr 2 Hr. Ntc.-Sub		312	(3 2900)	0 0000	0 0000	0 0000	(3 2900)	0.0000	(3 2900)	0 0000	(3 2900)	(1,026)		
IES Cr 30 Min Ntc -Sub		319	(4 5300)	0 0000	0 0000	0 0000	(4 5300)	0 0000	(4 5300)	0 0000	(4 5300)	(1,445)		
IES Cr 2 Hr. Ntc.-HV		0	(3 2900)	0 0000	0 0000	0 0000	(3.2900)	0.0000	(3 2900)	0 0000	(3 2900)	0		
IES Cr. 30 Min Ntc.-HV		779	(4 5300)	0 0000	0 0000	0 0000	(4 5300)	0 0000	(4 5300)	0 0000	(4 5300)	(3,529)		
IES Chg. 2 Hr. Ntc.												(6,000)		
IES Chg 30 Min Ntc														

2003 Unbundled Rate
Detail

	bill det. 2003 (1)	Subtotal Rate (2)	SBC/NTC (3)	Trans (4)	Dist (5)	BGS (6)	STC (7)	Subtotal 8=sum 3-7	Prelimn. MTC (9=2-8)	Shopping Credit (10=4+6)	Shp Cr Revenue (11=1*10)	MTC Oblig Adj. (12)	Adj MTC (13)
BPL	320,726	17 3645	1 1768	0 0000	10 8033	2 8956	0.9969	15 8728	1.4917	2.8958	9,288		
	320,726									2.90	9,288		
PSAL	163,538	21 8663	1 1768	0 0000	13 4248	2 8958	0 9969	18.4943	3.3720	2.8958	4,736		
	163,538									2.90	4,736		

Asset Schedule by FERC Account

	FERC Account	Description
Steam Production Plant	311	Structures and Improvements
	312	Boiler Plant Equipment
	313	Engines and Engine-Driven Generators
	314	Turbogenerator Units
	315	Accessory Electric Equipment
	316	Miscellaneous Power Plant Equipment
Other Production Plant	341	Structures and Improvements
	342	Boiler Plant Equipment
	343	Engines and Engine-Driven Generators
	344	Turbogenerator Units
	345	Accessory Electric Equipment
	346	Miscellaneous Power Plant Equipment
Hydro Production Plant	331	Structures and Improvements
	332	Boiler Plant Equipment
	333	Engines and Engine-Driven Generators
	334	Turbogenerator Units
	335	Accessory Electric Equipment
	336	Miscellaneous Power Plant Equipment
Nuclear Production Plant	321	Structures and Improvements
	322	Boiler Plant Equipment
	323	Engines and Engine-Driven Generators
	324	Turbogenerator Units
	325	Accessory Electric Equipment
	326	Miscellaneous Power Plant Equipment
Step-up Transformers	353	Step-up Transformers
Start-up Transformers		Start-up Transformers
Land	310-340	Land and Land Rights
Fuel & Materials	151-156, 163	Materials and Supplies (Fuel Stock and Other Materials)
	120.1-.6, 157	Nuclear Fuel Materials
Generation-Related Common Plant	FERC #	General Equipment

Asset Schedule

	Unit
Fossil	Bergen 1 Burlington 7 Burlington 10 Hudson 1 Hudson 2 Kearny 7 Kearny 8 Linden 1 Linden 2 Mercer 1 Mercer 2 Sewaren 1 Sewaren 2 Sewaren 3 Sewaren 4 Conemaugh 1 Conemaugh 2 Keystone 1 Keystone 2
Nuclear	Hope Creek Salem 1 Salem 2 Peach Bottom 2 Peach Bottom 3

Generation Related Assets	Central Maintenance System Maintenance Testing Lab Step-up Transformers Start-up Transformers Land Fuel & Materials General Plant Future Societal Benefits receivable (Account 130) for nuclear decommissioning pursuant to Section 12(a)(2) of the Act

	Unit
Peaking	Bayonne 1 Bayonne 2 Bergen 3 Burlington 8 Burlington 9 Burlington 11 Conemaugh A (DG) Conemaugh B (DG) Conemaugh C (DG) Conemaugh D (DG) Edison 1 Edison 2 Edison 3 Essex 9 Essex 10 Essex 11 Essex 12 Hudson 3 Kearny 9 Kearny 10 Kearny 11 Kearny 12 Keystone 3 (DG) Keystone 4 (DG) Keystone 5 (DG) Keystone 6 (DG) Linden 3 Linden 5 Linden 6 Linden 7 Linden 8 Mercer 3 National Park 1 Salem 3 Sewaren 6 Yards Creek 1 Yards Creek 2 Yards Creek 3

GENERATION FIXED TRANSFER VALUE

$5,068	Net After Tax Book Value
(3,300)	Stranded Cost
$1,768*	Transfer Value
600	MTC
$2,368	Amount Paid by Genco to PSE&G

* Plus Generation-Related Assets, including Nuclear Fuel and Materials & Supplies at Book Value.

ATTACHMENT 5

OFF-TARIFF RATE AGREEMENTS APPROVED OR PENDING AS OF MARCH 3, 1999

APPROVED

PSE&G OTRA 96-1	Circuit Foil
PSE&G OTRA 96-2	Ford
PSE&G OTRA 96-3	Merck
PSE&G OTRA 97-1	Ball Plastic
PSE&G OTRA 97-2	Aluminum Shapes
PSE&G OTRA 97-3	BASF
PSE&G OTRA 97-4	Camden Iron
PSE&G OTRA 97-5	Amerada Hess
PSE&G OTRA 97-6	Passaic Valley Sewerage Commission
PSE&G OTRA 97-7	Johnson & Johnson
PSE&G OTRA 97-8	Union Carbide
PSE&G OTRA 97-9	Port Authority Transit Corporation
PSE&G OTRA 98-1	Nabisco
PSE&G OTRA 98-2	Passaic Valley Sewerage Commission One year extension of OTRA 97-6

PENDING

PSE&G OTRA 98-3	Marcal
PSE&G OTRA 99-1	Garwood Paper
PSE&G OTRA 99-2	Daily News
PSE&G OTRA 99-3	Huntsman

NEW AND REVISED SECTIONS

OF THE

STANDARD TERMS AND CONDITIONS

AND ASSOCIATED RATE SCHEDULES

OF PSE&G'S

TARIFF FOR ELECTRIC SERVICE

FEBRUARY 1, 1999 - CAPACITY & ENERGY (NET BACK)

15. **THIRD PARTY SUPPLIER SERVICE PROVISIONS**

15.1. Alternate Electric Supply: Customers served on any of the applicable rate schedules of this Tariff for Electric Service and who desire to purchase their electric supply of capacity, transmission, and energy, hereinafter referenced as electric supply, from a third party supplier must execute an authorization form. Authorization forms are included in the enrollment package described in Section 15.1.1. Customers who are not enrolled with a third party supplier will continue to receive their electric supply from Public Service. The customer may act as a third party supplier for his account if they meet all of the requirements of Section 15.1.2.

15.1.1. Enrollment: Customers may request an enrollment package from Public Service which in addition to providing general information regarding electric supply, describes the process necessary for a customer to obtain a third party supplier of electric supply. This enrollment package will be provided to the customer at no charge and may be obtained by calling or writing Public Service or visiting a Customer Service Center. Once the customer has chosen a third party supplier, the customer must execute the authorization form contained in the enrollment package, noting the name of the third party supplier. Upon written request of the customer, Public Service will provide customer usage information to any number of third party suppliers at a rate of $2.00 per copy, billable to the customer.

15.1.2. Third Party Supplier: A third party supplier is a retail energy and capacity provider that has executed a Third Party Supplier Master Service Agreement with Public Service so as to be eligible to furnish electric supply with delivery to the retail customer by Public Service. This Agreement requires that the third party supplier satisfy the creditworthiness standards of Public Service, be licensed by the Board of Public Utilities and any other appropriate New Jersey state agencies, and satisfy any and all other legal requirements necessary for participation in the New Jersey retail energy market. By determining a third party supplier credit worthy, Public Service makes no express or implied warranties or guarantees of any kind with respect to the financial or operational qualifications of such third party supplier.

15.2. Initiation of Service: In order to be eligible to receive electric supply from a third party supplier, the customer must contract with a third party supplier to obtain electric supply for delivery to the customer by Public Service. Delivery of electric supply to retail customers will be provided in accordance with the terms of the Third Party Supplier Master Service Agreement. The customer is required to notify Public Service of its initial choice of third party supplier of electric supply as well as any subsequent changes in third party supplier, through the use of the authorization form included in the enrollment package. Initiation of service will become effective on the customer's next scheduled meter reading date that is at least fifteen (15) days following the receipt of the authorization form by Public Service. Such selection shall remain in effect for a period of at least twelve (12) months, subject to the conditions as stated within this subsection.

Once Public Service has received the signed authorization form for the initial, or subsequent, enrollment with a third party supplier, which process is as set forth in this subsection and in Section 15.1, Public Service will confirm the customer's participation with its designated third party supplier as well as send a letter of confirmation to the customer. In the event of a dispute, assignment of a customer will not occur unless and until the dispute is resolved. Once assignment has occurred, the third party supplier will be required to provide all of the electric supply consumed on the Public Service customer's account (single point of delivery).

15.2.1. Customer Change of Third Party Supplier: If a customer subsequently elects to change its third party supplier, the customer must sign an authorization form as set forth in Section 15.1 and Section 15.2. Service from this alternate third party supplier will become effective on the customer's next scheduled meter reading date that is at least fifteen (15) days following the receipt of the authorization form by Public Service. Upon enrollment with a third party supplier, the customer may not change its third party supplier for a minimum period of twelve (12) months.

15.2.2. Customer Return to Public Service Rate Schedule Electric Supply: If the customer subsequently elects to return to Public Service as its supplier of electric supply, the customer must sign an authorization form as set forth in Section 15.2.1. The return to Public Service will become effective on the customer's next scheduled meter reading date that is at least fifteen (15) days following the receipt of the authorization form by Public Service and shall be for a minimum term of twelve (12) months. However, if a customer's third party supplier no longer satisfies the requirements of Section 15.1.2, Third Party Supplier, such customer shall immediately return to, and receive electric supply from, Public Service under customer's applicable rate schedule until customer selects another third party supplier in accordance with Section 15.2.1. Where the customer's return to Public Service, as its supplier of electric supply, is caused by the customer's third party supplier no longer satisfying the requirements of Section 15.1.2, Third Party Supplier, the customer can elect an alternate third party supplier prior to the expiration of the minimum period of twelve (12) months indicated herein.

15.2.3. Third Party Supplier's Termination of Customer's Electric Supply: A third party supplier will not be permitted to physically connect or disconnect energy service to a customer. A third party supplier shall send written or electronic notification to Public Service of any contractual termination, whether by cancellation or expiration, of a supply agreement between itself and its customer, and shall simultaneously notify the customer of the same. Termination of such agreement will become effective on the customer's next scheduled meter reading date that is at least fifteen (15) days following the receipt of the termination notice by Public Service. Unless the customer directs Public Service in writing to the contrary, Public Service shall provide electric supply service to the customer on the effective date of the termination of the customer supply agreement, in accordance with Public Service's applicable tariff and Board of Public Utilities rules and regulations.

If the customer disputes the termination, which occurs by cancellation, by simultaneous written notice to Public Service and to its third party supplier, Public Service will not begin supplying electric supply to the customer until the customer agrees to the termination. Such electric supply will continue to be supplied by the third party supplier until such time that the dispute is resolved or the Board of Public Utilities approves in writing the termination of the agreement between the customer and the third party supplier. At that time the termination will become effective on the customer's next scheduled meter reading date that is at least fifteen (15) days following the receipt of the termination notice by Public Service. In the case of termination, which occurs by expiration, Public Service will furnish electric supply if the customer has not selected another third party supplier in accordance with Section 15.2.1.

15.2.4. Administrative Fee: Upon selection of a third party supplier an administrative charge of $20.00 ($21.20 including New Jersey Sales and Use Tax, SUT) will be applied to the customer's account on Rate Schedules RS, RHS, and RLM. The administrative charge for Rate Schedules GLP, LPL, HTS, HS, BPL and PSAL is $50.00 ($53.00 including SUT). The administrative fee is applicable each time a customer enrolls with a third party supplier or returns to Public Service. Public Service will waive this administrative fee if the customer's return to Public Service furnished electric supply is necessitated by the customer's third party supplier no longer satisfying the requirements of Section 15.1.2, Third Party Supplier.

15.3. **Customer Billing Process:** Public Service will provide one combined bill to the third party supplier's retail customer(s) containing both Public Service charges and third party supplier information including their name, telephone number, current electric supply charges, unpaid prior balance electric supply charges, and the total electric supply charges. Only Public Service owned, installed, and read meters will be used to determine customer usage for the purpose of calculating Public Service charges.

15.3.1. **Payment of Bills:** Payment of bills, including third party supplier's charges for electric supply, shall be made to Public Service and shall be in accordance with Section 9, Meter Reading and Billing, of these Standard Terms and Conditions. Where a partial payment is received, in lieu of full payment, it shall be applied in the following order: (i) undisputed Public Service customer charges; (ii) undisputed third party supplier customer charges; (iii) disputed Public Service customer charges; and (iv) disputed third party supplier customer charges. Any customer overpayment will be held in the customer's Public Service account to be applied against future customer bills or will be refunded to the customer at the customer's request. In the event that any customer checks are returned unhonored by a bank, such debits will be applied in inverse order to the order set forth above.

15.3.2. **Late Payment Charges:** In the case of electric supply furnished by third party supplier, Section 9.12, Late Payment Charge, of these Standard Terms and Conditions is to be applicable only to Public Service customer charges. Customer shut-offs in cases where there is non-payment to Public Service for its customer charges are only performed in accordance with Section 12, Discontinuance of Service, of these Standard Terms and Conditions.

15.3.3. **Billing Disputes:** In the event of a billing dispute between the customer and the third party supplier, Public Service's sole duty is to verify its customer charges and billing determinants. Customer continues to remain responsible for the timely payment of all Public Service charges in accordance with Section 9, Meter Reading and Billing, and Section 15.3.1, Payment of Bills, of these Standard Terms and Conditions, regardless of third party supplier billing dispute(s). All questions regarding third party supplier's charges or other terms of the customer's agreement with a third party supplier are to be resolved between the customer and its third party supplier. Public Service will not be responsible for the enforcement, intervention, mediation, or arbitration of agreements entered into between third party supplier customers and third party suppliers. Billing disputes that may arise regarding Public Service's charges shall be subject to Section 12, Discontinuance of Service, of these Standard Terms and Conditions.

15.4. **Continuity of Service:** In addition to the terms specified in Section 12, Discontinuance of Service, and Section 14, Service Limitations, of these Standard Terms and Conditions, Public Service shall have the right (i) to require a third party supplier's electric supply sources to be disconnected from Public Service's electrical system; (ii) to otherwise curtail, interrupt, or reduce a third party supplier's electric supply; or (iii) to disconnect a third party supplier's customer(s) whenever Public Service determines, or whenever Public Service is directed by PJM, that such a disconnection, curtailment, interruption or reduction is necessary to facilitate construction, installation, maintenance, repair, replacement or inspection of any of Public Service's or PJM members' facilities; to maintain the safety and reliability of Public Service's electrical system and any generation facilities attached thereto; or due to Emergencies, minimum generation ("light load") conditions, forced outages, potential overload of Public Service's or PJM's transmission and/or distribution circuits or events of Force Majeure including, but not limited to, those events specified in Section 14.1, Continuity of Service, of these Standard Terms and Conditions.

15.5. **Limitations of Liability:** In addition to those items enumerated in these Standard Terms and Conditions, Public Service shall not be liable in any way for any failure in whole or in part, temporary or permanent, to deliver electric energy under any rate schedule within this tariff. Further, Public Service shall not be liable, to either third party supplier customers or to third party suppliers, in any way for any errors in the calculation of the load profile, demand, and/or electric energy usage, nor will Public Service be responsible for any additional electric supply costs and/or penalties incurred by third party supplier customers or third party suppliers as a result of any such errors. Load profiling is a process that determines customer's hourly energy usage by taking a customer's total monthly billed kWh and deriving hourly usage amounts based upon the hourly usage patterns of a relevant sample group.

Public Service shall have no responsibility with respect to such electric energy before third party supplier delivers or has delivered on its behalf such electric energy to Public Service or after Public Service delivers such electric energy to customer at customer's meter, or on account of anything which may be done, happen or arise with respect to such electric energy before such delivery to Public Service or after such delivery to the customer.

15.6. **Metering:** In addition to the terms specified in Section 9, Meter Reading and Billing, of these Standard Terms and Conditions, for customers choosing a third party supplier to obtain its electric supply and having a peak load of 100 kW or greater for ten (10) out of the prior twelve (12) billing months, Public Service will, in all circumstances install an interval metering device for customer billing purposes, at the customer's expense, which will permit the recording of usage and demand data in a maximum of hourly increments, or in increments as specified in the customer's particular rate schedule, whichever is smaller. The customer will be required to pay Public Service a set-up fee of $XXX.XX and a monthly service fee of $XX.XX for such interval metering devices. This fee is based upon the customer providing a single phase 120 volt electric supply source, an individual message business control office line and arrange for data transmission of metering information and termination of data on an RJ45S modular jack. Other options may be available for an additional set-up and/or monthly service fee. The charges for the set-up fee and monthly service fee will be billed upon completion of the installation of the interval metering device and will be included with the customer's next Public Service bill. If the interval metering device is not installed prior to customer's initiation of third party supply then customer's usage and demand will be determined by employing load profiling based upon the customer's rate schedule or historical customer usage and demand data, at the discretion of Public Service.

If the customer of a third party supplier is not required to have an interval metering device as indicated above, hourly usage and demand, where applicable, will be determined by employing load profiling based upon the customer's rate schedule, unless the third party supplied customer chooses to have an interval metering device installed in which case the customer will be billed as indicated above. If a customer of a third party supplier has an interval metering device and said device is not operational, customer's hourly usage and demand, where applicable, will be determined by employing load profiling based upon the customer's rate schedule or historical customer usage and demand data, at the discretion of Public Service.

If a customer of a third party supplier already has an installed interval metering device on its premises when electric retail choice is implemented, or one is installed subsequent to the initiation of retail choice, which interval metering device was installed solely for the purpose of participating in Interruptible Electric Service (IES) , the customer will be required to pay Public Service the aforementioned set-up fee and monthly service fee charged for interval metering devices. The charges for the set-up fee and monthly service fee will be included with the customer's next Public Service bill.

Those customers participating in the Curtailable Electric Service (CES) program may continue to participate in that program. If a customer of a third party supplier already has an installed interval metering device on its premises when electric retail choice is implemented, or one is installed subsequent to the initiation of retail choice,which interval metering device was installed solely for the purpose of participating in CES, and the customer chooses to no longer participate, or alternatively is disqualified for this Special Provision because of continual failure to meet agreed upon load reductions, the customer will be required to pay Public Service as indicated above for IES.

If a customer of a third party supplier already has an installed interval metering device on its premises when electric retail choice is implemented, or one is installed subsequent to the initiation of electric retail choice, for purposes including but not limited to conducting load research, Public Service may at its option remove that interval metering device. If customer chooses to retain that interval metering device then customer will be required to pay Public Service as indicated above for IES.

16. TERMINATION, CHANGE OR MODIFICATION OF PROVISIONS OF TARIFF

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey.

Public Service may at any time and in any manner permitted by law, and the applicable rules and regulations of the Board of Public Utilities of the State of New Jersey, terminate, or change or modify by revision, amendment, supplement, or otherwise, this Tariff or any part thereof, or any revision or amendment hereof or supplement hereto.

OTHER TARIFF CHANGES

Standard Terms & Conditions

2.7. **Temporary Service:** Where service is to be used at an installation for a limited period and such installation is not permanent in nature, the use of service shall be classified as temporary. In such cases, the customer may be required to pay to Public Service the cost of installation and removal of the facilities required to furnish service and such service being only available with electric supply provided by Public Service. The minimum period of temporary service for billing purposes shall be one month.

After two years of service a temporary service installation shall be eligible for refunds. excluding the first two annual service periods, refunds equal to 10% of the revenue received by Public Service during an annual service period shall be made at the end of such period. In no case shall the total amount refunded be in excess of the installation cost paid by the customer, nor shall refunds be made for more than eight consecutive annual service periods.

Temporary service will be furnished only under Rate Schedules GLP, LPL, and HTS except that it will not be supplied for cogeneration or standby purposes under any rate schedule at locations where electric service is regularly supplied from another source, nor will it be supplied under Rate Schedules BPL and PSAL.

3. EXTENSION OF DISTRIBUTION LINES

3.2. **Individual Residential Customer:** Where the cost to Public Service for an extension to serve an individual permanent residential customer does not exceed $0.50 per estimated. annual kilowatthour usage or where the length of an extension is 2500 feet or less, Public Service will make the necessary extension upon receiving from the customer an application for service. Such application shall be made by the owner of the property or by a responsible tenant and shall be an indefinite period; not less, however, than the number of years necessary to produce, at the normal annual distribution charge, the cost of the extension.

3.2.1. Where the cost of an extension exceeds the amount which Public Service will install without cost to a customer, in accordance with Section 3.2, the excess cost of the extension shall be deposited and remain with Public Service without interest. As additional customers are supplied from along this extension, an adjustment will be made to the depositor based on the point along the extension that such additional customers are connected. In no event shall more than the original deposit be returned to the depositor nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned. Public Service will waive the deposit required where the amount is $100.00 or less.

3.2.2. Where the cost of Public Service for an extension to serve an individual permanent residential customer exceeds the amount which Public Service will install without cost to the customer, in accordance with Section 3.2, Public Service and the customer may agree upon a monthly revenue guarantee, in lieu of a deposit pursuant to Section 3.2.1. This monthly revenue guarantee shall be based upon a guaranteed monthly kilowatthour usage billed at customer's applicable rate, net of production and transmission charges. The guaranteed monthly kilowatthour usage shall be determined by dividing one-twelfth of the total cost of the extension by $0.50 per kilowatthour.

3.3. **Residential Land Developer:** Where applications for extensions into newly developed tracts of land are made by individuals, partnerships, or corporations interested in the development or sale of land, but not as ultimate residents, Public Service may require a deposit from the applicant covering the entire cost of the extension necessary to serve the tract.

3.3.1. Extension deposits shall not carry interest and are to be returned as hereinafter provided to the depositor when and as street lights have been installed or new building abutting on such extensions are under construction and have been framed and roofed.

3.3.2. The deposit shall be returned in an amount equal to $0.50 per estimated annual kilowatthour usage from each such completion on said extension. If during a ten-year period from the date of the original deposit, the actual annual kilowatthour usage, during any year of said ten-year period, from premises and street lights abutting upon said extension exceeds the estimated annual kilowatthour usage which was the basis for the previous deposit return, there shall be returned to the depositor an additional amount equal to $0.50 per annual kilowatthour times such excess kilowatthour usage. In no event shall more than the original deposit be returned to the depositor nor shall any part of the deposit remaining after ten years from the date of the original deposit be returned.

3.4. **Commercial and Industrial:** Public Service may require any customer to deposit an amount equal to the entire cost of the new facilities required to supply service, such amount to be subject to refund as follows: At the end of the first service year, an amount without interest equal to $140.00 times the sum of the year's monthly kilowatts billed to and paid by the customer for electric service delivered by Public Service for that year will be refunded, and thereafter refunds similarly determined will continue each year until such time as the accumulated annual refunds are equal to but not in excess of the sum deposited; provided, however, that any part of the deposit not returned to the customer within ten years after the beginning of the first service year shall remain the property of Public Service. No refund will be made if service is discontinued prior to the expiration of the first service year.

Where it is necessary to provide additional facilities to serve increased requirements of an existing customer, Public Service may require the customer to deposit an amount equal to the cost of such additional facilities. This amount shall be subject to refund as outlined in the preceding paragraph, except that the refunds will be calculated at $140.00 times the sum of the year's monthly kilowatts of the excess over a predetermined base.

4.2. **Types of Service:** Subject to the restrictions in Section 4.1, the types of service available, with their nominal voltages from the specified supply system are:

	Supply System	Type of Service	Volts
4.2.1.	Secondary Distribution Service:	Single-phase, two-wire	120
		Single-phase, three-wire	120/240
		Single-phase, three-wire	120/208
		Three-phase, three-wire	240
		Three-phase, four-wire	120/240
		Three-phase, four-wire	120/208
		Three-phase, four-wire	277/480
4.2.2.	Primary Distribution Service:	Three-phase, four-wire	2,400/4,160
		Three-phase, four-wire	13,200
4.2.3.	Subtransmission Service:		
		Three-phase, three-wire	26,400
		Three-phase, three-wire	69,000
	High Voltage Service:	Three-phase, three-wire	138,000
		Three-phase, three-wire	230,000

5. SERVICE CONNECTIONS

5.2. Overhead Service: For overhead service in overhead zones, Public Service will furnish, install, and maintain the overhead service facilities to the point of connection to the customer's facilities.

Public Service will supply, without cost to the customer, 750 feet of single-phase or 600 feet of three-phase overhead service connection, as measured from the curb line nearest to the customer's facilities to the pole nearest the point of connection. If the length of service connection exceeds the aforementioned, the customer may be required to pay the cost of such excess, such charge being equal to the amount by which the cost of the service connection exceeds the greater of either $0.25 per annual kilowatthour for Residential Rate Schedules RS, RHS, and RLM, hereinafter Residential Rates, or $65.00 times the sum of the year's monthly kilowatts for Rate Schedules GLP, LPL, HTS, HS, BPL, and PSAL receiving secondary, primary or subtransmission service, as applicable, hereinafter Commercial and Industrial Rates, as estimated by Public Service, or the cost of the service connection which otherwise would be furnished without charge as provided above. The service drop between the pole nearest to the point of connection and the point of connection shall be installed at the expense of Public Service.

5.3. Underground Service in Underground Zone: For underground service in underground zones, Public Service will furnish, install, and maintain the underground service facilities to the point of connection to customer's facilities.

Public Service will supply, without cost to the customer, up to 100 feet of underground service facilities measured at right angles to the curb nearest the point of service connection to the customer's facilities. If the length of service connection exceeds the aforementioned, the customer may be required to pay the cost of such excess, such charge being equal to the amount by which the cost of the service connection exceeds the greater of either $0.25 per annual kilowatthour for Residential Rates or $65.00 times the sum of the year's monthly kilowatts for Commercial and Industrial Rates as estimated by Public Service, or the cost of the service connection which would be furnished without charge as provided above.

5.4. Underground Service in Overhead Zone:

5.4.1. Secondary Distribution Service: Where underground service in an overhead zone is to be supplied, and secondary voltage supply from overhead facilities is inadequate for the size of customer's load, the customer shall furnish and install at his expense and in accordance with the specifications of Public Service the primary conduits and any necessary manholes, which will be maintained by Public Service. The customer shall also be required to furnish, install, and maintain all secondary conduits and conductors and provide space on his property for necessary transformation.

Where underground service in an overhead zone is to be supplied, and secondary voltage supply from overhead facilities is adequate for the size of customer's load, such service will be supplied under the following conditions:

At Request of Customer: The customer shall furnish and install the service facilities at his own expense in accordance with the specifications of Public Service. Public Service will connect the service conductors and maintain the service facilities without charge to the customer.

Operating Reasons Beyond the Control of Public Service: The customer shall furnish and install at his expense and in accordance with the specifications of Public Service the service conduit which will be maintained by Public Service. Public Service will furnish, install, and maintain the service conductors to the point of connection to customer's facilities. Where the distance from the nearest curb line to the point of connection to customer's facilities, measured at right angles to the curb line is 100 feet or less, the service conductors will be furnished in place without charge. If the length of service conductors exceeds 100 feet, the customer may be required to pay a charge equal to the amount by which the cost of service conductors exceeds the greater of either $0.25 per annual kilowatthour for Residential Rates or $65.00 times the sum of the year's monthly kilowatts for Commercial and Industrial Rates as estimated by Public Service, or the cost of the service conductors which otherwise would be furnished without charge as provided herein.

5.4.2. **Primary Distribution Service:** Where underground service in an overhead zone is to be supplied, and primary voltage supply is required because of the size of the customer's load, such service will be supplied under the following conditions:

At Request of Customer or for Operating Reasons Beyond the Control of **Public Service:** The customer shall furnish and install at his expense and in accordance with the specifications of Public Service the service conduit and any necessary manholes which will be maintained by Public Service. Public Service will furnish, install, and maintain the service conductors to the point of connection to customer's facilities. Public Service will supply, without cost to the customer, 750 feet of single-phase or 600 feet of three-phase conductors measured at right angles from the nearest curb to the point of connection to the customer's facilities. If the length of service conductors exceeds 750 feet of single-phase or 600 feet of three-phase, the customer may be required to pay a charge equal to the amount by which the cost of the primary service conductors exceeds the greater of either $75.00 times the sum of the year's monthly kilowatts as estimated by Public Service or the cost of the service conductors which otherwise would be furnished without charge as provided herein.

5.4.3. **Subtransmission Service:** Where underground service in an overhead zone is to be supplied, and subtransmission voltage supply is required because of the size of customer's load, such service will be supplied under the following conditions:

At Request of Customer: The customer shall furnish and install at his expense and in accordance with the specifications of Public Service, the service conduit and any necessary manholes which will be maintained by Public Service. Public Service will furnish, install, and maintain the service conductors to the point of connection to customer's facilities. The charge to the customer shall be the cost of the facilities furnished and installed by Public Service minus the cost of equivalent overhead construction.

Operating Reasons Beyond the Control of Public Service: The customer shall furnish and install at his expense and in accordance with the specifications of Public Service, the service conduit and any necessary manholes which will be maintained by Public Service. Public Service will furnish, install, and maintain the service conductors to the point of connection to customer's facilities. Where the distance from the nearest curb line to the point of connection to customer's facilities, measured at right angles to the curb line is 100 feet or less, the service conductors will be furnished in place without charge. If the length of service conductors exceeds 100 feet, the customer may be required to pay a charge equal to the amount by which the cost of the service conductors exceeds the greater of either $75.00 times the sum of the year's monthly kilowatts as estimated by Public Service or the cost of the service conductors which otherwise would be furnished without charge as provided herein.

7.4. **Tampering:** In the event it is established that Public Service meters or other equipment on the customer's premises have been tampered with, and, such tampering results in incorrect measurement of the service supplied, the cost for such electric service under the applicable rate schedule, exclusive of any Energy and Capacity Credit, based upon the Public Service estimate from available data and not registered by Public Service meters shall be paid by the beneficiary of such service. In the case of a residential customer, such unpaid service shall be limited to not more than one year prior to the date of correcting the tampered account and for no more than the unpaid service under the applicable rate schedule, exclusive of any Energy and Capacity Credit, alleged to be used by such customer. The beneficiary shall be the customer or other party who benefits from such tampering. The actual cost of investigation, inspection, and determination of such tampering, and other costs, such as but not limited to, the installation of protective equipment, legal fees, and other costs related to the administrative, civil or criminal proceedings, shall be billed to the responsible party. The responsible party shall be the party who either tampered with or caused the tampering with a meter or other equipment or knowingly received the benefit of tampering by or caused by another. In the event a residential customer unknowingly received the benefit of meter or equipment tampering, Public Service shall only seek from the benefiting customer the cost of the service provided under the applicable rate schedule, exclusive of any Energy and Capacity Credit, but not the cost of investigation.

These provisions are subject to the customer's right to pursue a bill dispute proceeding pursuant to N.J.A.C. 14:3-7.14.

Tampering with Public Service facilities may be punishable by fine and/or imprisonment under the New Jersey Code of Criminal Justice.

9.9. **Budget Plan (Equal Payment Plan):** Customers billed under Rate Schedules RS or RHS or GLP (where GLP electric service is used for residential purposes in buildings of four or fewer units) shall have the option of paying for their Public Service charges in equal, estimated monthly installments. The total Public Service charges for a twelve-month period will be averaged over twelve months and may be paid in twelve equal monthly installments. A review between the actual cost of service and the monthly budget amount will be made at least once in the budget plan year. A final bill for a budget plan year shall be issued at the end of the budget plan and shall contain that month's monthly budget amount plus any adjustments will be made if actual charges are more or less than the budget amount billed.

10. COGENERATON OR STANDBY SERVICE

Electric service from sources other than that delivered by Public Service system shall not be used for the operation of customer's electrical equipment without previous written notice to Public Service.

10.1. Cogeneration Service: Where the service delivered by Public Service, which shall include all service delivered to the customer at any one location, is used to supplement customer's private plant service or any other source of electric service or motive power through electrical or mechanical means or by means of operations procedures, such service shall constitute cogeneration service and will be furnished under all rate schedules.

Where customer with the written consent of Public Service operates private plant service in parallel with the cogeneration service furnished by Public Service, Public Service may re-energize the service, following an interruption, without prior notice to the customer.

10.2. Standby Service: Where the service delivered by Public Service, which shall include all service delivered to the customer at any one location, is available in the event of failure of customer's private plant service or any other source of electric service or motive power, or where the service in effect serves to relieve or to sustain the effective operation of any other source of power, or where otherwise requested by the customer, such service shall constitute standby service and will be furnished under all rate schedules.

10.2.1. Maintenance Power: When a FERC Qualifying Facility schedules maintenance with prior notification to and approval from Public Service for maintenance power or in the event of failure of customer's cogeneration or small power production FERC Qualifying Facility, that portion of the customer's monthly maximum demand related to this service will not be subject to the Public Service Kilowatt Charges. Where a customer receives electric supply from a third party supplier, the customer will not be subject to the Kilowatt Charges, net of any Capacity and Transmission Credits as designated in the applicable rate schedule.

RATE SCHEDULES RS, GLP, LPL, BPL, PSAL, WH, WHS, RHS, HS, HTS, & RLM

ADJUSTMENT CHARGES:

Charges will be made for the estimated January through December annual period average cost per kilowatthour to Public Service of costs associated with each of Societal Benefits, Non-Utility Generation, and Securitization Transition Charges. Prior to January of each year, the estimated average cost of each charge component listed below will be determined for the succeeding annual period. These estimated average costs will be adjusted for any under- or over-recoveries together with applicable interest thereon, which may have occurred during the operation of the Company's previously approved mechanism. Interest shall be determined monthly on the cumulative under- or over-recoveries average balance for the month utilizing the Company's allowed overall rate of return. The applicable charge will be the total cost in cents per kilowatthour adjusted by factors to reflect applicable losses from the sales of electricity and also the addition of Applicable Taxes. Any net charge or credit will apply to all kilowatthours billed each month of the succeeding annual period. In the event that a major change in the total average cost occurs during the annual period, a revised estimated average cost will be calculated and applied for the remainder of the period in accordance with the above.

Societal Benefits Charge:
This charge shall recover costs associated with Societal Benefits including: 1) Demand Side Management Programs; 2) Environmental Remediation; 3) Nuclear Decommissioning Funding Requirements; 4) Nuclear Fuel Disposal Assessment; 5) Uncollectibles; 6) Restructuring Costs; 7) Social Program Costs; and 8) Applicable Taxes.

Non-Utility Generation Charge:
This charge shall recover costs associated with non-regulated generation costs which are Related to ~~comprised of~~ existing (as of July 1. 1997) long term contractual power purchase arrangements approved by the Board and/or established under requirements of the Public Utility Regulatory Policies Act of 1978.

Securitization Transition Charge :
This charge shall fully recover the bondable stranded costs, and provide for adjustment in a manner approved by the Board of the initial transition bond charge prior to the closing of the related transition bonds to reflect the actual rate of interest thereon and all other costs, including any required overcollateralization, associated with the issuance of such transition bonds.

ENERGY AND CAPACITY CREDITS:

A customer may choose to receive electric supply from Public Service or a third party supplier as defined in Section 15 of the Standard Terms and Conditions of this Tariff..

A customer who receives electric supply from a third-party supplier will receive a Market Energy Credit, a Capacity Credit, a Transmission Credit, and an Ancillary Services Credit. collectively known as Energy and Capacity Credits, in addition to the above adjustment charges in each billing period. These Credits will be adjusted for losses at secondary voltages **[customize voltage reference to particular rate schedule - secondary, primary, sub trans. & trans., as appropriate]** and applicable taxes. Energy and Capacity Credits will be computed as measured or calculated by Public Service in accordance with the following: (1) Market Energy Credit is based upon the customer's kilowatthour usage in each hour times the customer's Locational Marginal Price of Energy, (2) Capacity Credit is based upon the customer's peak load contribution (in kilowatts) times the monthly Capacity Revenue Credit determined by Public Service based on PJM's Capacity Credit Market's Market Clearing Prices (on a dollars per kilowatt per month basis), (3) Transmission Credit is based upon the customer's transmission obligation (in kilowatts) times Public Service's Network Integration Transmission Service rate, or its successor, divided by 12, as contained in the PJM Open Access Transmission Tariff (on a dollars per kilowatt per month basis), and (4) Ancillary Services Credit is based on the customer's kilowatthours usage times the applicable monthly rate for such services.

SPECIAL PROVISIONS:

(XX) Customers who desire to purchase their electric supply from a third party supplier must execute an authorization form and are subject to Section 15 of the Standard Terms and Conditions of this Tariff for Electric Service. **(XX to be last Special Provision prior to tax provisions)**

RATE SCHEDULE GLP

SPECIAL PROVISIONS:

(b) **Standby Service:** When Standby Service, as defined in Section 10.2 of the Standard Terms and Conditions, is delivered, the following charges and provisions shall apply:

(b-1) **Standby Service Charge:** Where Public Service must provide reserve capacity and stand ready at all times to deliver electric supply , a standby charge of $3.64 ($3.86 including SUT) per kilowatt of Standby Capacity shall be applied. Where a customer receives electric supply from a third party supplier, that customer will receive a Standby Credit as part of the Energy and Capacity Credits. The Standby Credit is based upon the product of the Standby Capacity times the sum of the Capacity Credit plus the Transmission Credit, pursuant to this Rate Schedule's Section on Energy and Capacity Credits (both in dollars per kilowatt per month), adjusted by the Board of Public Utilities approved coincidence factor of 0.15.

(b-2) **Determination of Standby Capacity:** The standby kilowatt capacity shall be equivalent to the difference between the customer's firm capacity and the total load the customer would require in the event of a failure as determined by Public Service. The total load shall be equivalent to 85% of the customer's kilovoltampere requirement, as rated by Public Service. The customer may be required to furnish and install, at his own expense, a load-limiting device, approved by Public Service, which shall be maintained by Public Service at customer's expense. The maximum kilovoltampere demand setting of the load-limiting device shall be under the sole control of and be adjusted only by Public Service, and shall not be tampered or interfered with in any way by the customer. At any time that there is an increase in the standby kilowatt capacity, a new term shall commence; the standby kilowatt capacity may not be revised downward during any term.

(b-3) **Minimum Charge:** In lieu of the minimum charge hereinbefore set forth, the minimum charge in any month shall be the Standby Service Charge. The waiver of minimum charge is not applicable.

(b-4) **Parallel Operation:** Customer shall not, at any time, operate private plant service in parallel with the service furnished by Public Service except with the written consent of Public Service.

(b-5) **Maintenance Power:** When a FERC Qualifying Facility schedules maintenance with prior notification to and approval from Public Service for maintenance power or in the event of failure of customer's cogeneration or small power production FERC Qualifying Facility, that portion of the customer's monthly maximum demand related to this service will not be subject to the Kilowatt Charges hereinbefore set forth. Where a customer receives electric supply from a third party supplier, the customer will not be subject to the Kilowatt Charges hereinbefore set forth, net of any Capacity and Transmission Credits.

(d) **Police Recall or Fire Alarm System Service:** Unmetered police recall or fire alarm system service will be furnished for signaling lamps, bells, or horns with an individual rating not greater than 100 watts or 1/8-horsepower, as rated by Public Service, at a charge of 18¢ (19¢ including SUT) per month for each signaling lamp, bell, or horn connected, but the total charge shall in no case be less than $1.81 ($1.92 including SUT) per month. No other energy-using devices shall be connected to the police recall or fire alarm system. The customer shall provide, at his own expense, all necessary equipment and wiring, including the service connection. This Special Provision is only available with electric supply furnished by Public Service.

(i) **Curtailable Electric Service:** Curtailable Electric Service will be furnished when and where available. Those customers that receive electric supply from a third party supplier may continue to receive service under this Special Provision. If a third party supplied customer chooses to no longer participate, or alternatively is disqualified for this Special Provision because of continual failure to meet agreed upon load reductions, the customer will be required to pay Public Service, in accordance with Standard Terms and Conditions, Section 15.6, Metering, for the installed interval metering device. Curtailable Electric Service will be furnished under the following conditions:

(i-1) A customer agrees to take service under this rate schedule at a single service connection and agrees to curtail his load during times of curtailment by the amount stated in his Application/Agreement. A credit of $6.11 ($6.48 including SUT) per kilowatt of average actual curtailed demand for each curtailment period will be applied to the customer's bill in a succeeding month. The curtailed demands will be measured as the difference, for each hour, between a customer-specific hourly load curve developed by Public Service for customer's normal business operation and the actual recorded hourly load during the curtailment period. The curtailment period will commence a minimum of one hour from the time of notification and end at the time indicated in the restoration call but not later than 8:00 P.M. as indicated in (i-3) below. For each applicable calendar month, the customer's individual curtailment period results will be summed to determine the appropriate credit. There will be no penalty for failure to curtail load or meet the agreed upon load reduction when notified. Continued failure by a customer to meet agreed upon load reduction, however, will result in customer's disqualification for this Special Provision and Public Service may remove from the customer's premises the interval metering device installed for this Special Provision.

RATE SCHEDULE LPL

SPECIAL PROVISIONS:

(d) **Standby Service:** When Standby Service, as defined in Section 10.2 of the Standard Terms and Conditions, is delivered, the following charges and provisions shall apply:

(d-1) **Standby Service Charge:** Where Public Service must provide reserve capacity and stand ready at all times to deliver electric supply , a standby charge of $3.64 ($3.86 including SUT) per kilowatt of Standby Capacity for Secondary Distribution Service or $2.58 ($2.73 including SUT) per kilowatt of Standby Capacity for Primary Distribution Service shall be applied. Where a customer receives electric supply from a third party supplier, that customer will receive a Standby Credit as part of the Energy and Capacity Credits. The Standby Credit is based upon the product of the Standby Capacity times the sum of the Capacity Credit plus the Transmission Credit, pursuant to this Rate Schedule's Section on Energy and Capacity Credits (both in dollars per kilowatt per month), adjusted by the Board of Public Utilities approved coincidence factor of 0.15.

(d-2) **Determination of Standby Capacity:** The standby kilowatt capacity shall be equivalent to the difference between the customer's firm capacity and the total load the customer would require in the event of a failure as determined by Public Service. The total load shall be equivalent to 85% of the customer's kilovoltampere requirement, as rated by Public Service. The customer may be required to furnish and install, at his own expense, a load-limiting device, approved by Public Service, which shall be maintained by Public Service at customer's expense. The maximum kilovoltampere demand setting of the load-limiting device shall be under the sole control of and be adjusted only by Public Service, and shall not be tampered or interfered with in any way by the customer. At any time that there is an increase in the standby kilowatt capacity, a new term shall commence; the standby kilowatt capacity may not be revised downward during any term.

(d-3) **Minimum Charge:** In lieu of the minimum charge hereinbefore set forth, the minimum charge in any month shall be the Standby Service Charge less any Interruptible Service Credit if applicable. The waiver of minimum charge is not applicable.

(d-4) **Parallel Operation:** Customer shall not, at any time, operate private plant service in parallel with the service furnished by Public Service except with the written consent of Public Service.

(d-5) **Maintenance Power:** When a FERC Qualifying Facility schedules maintenance with prior notification to and approval from Public Service for maintenance power or in the event of failure of customer's cogeneration or small power production FERC Qualifying Facility, that portion of the customer's monthly maximum demand related to this service will not be subject to the Kilowatt Charges hereinbefore set forth. Where a customer receives electric supply from a third party supplier, the customer will not be subject to the Kilowatt Charges hereinbefore set forth, net of any Capacity and Transmission Credits.

(e) **Interruptible Service :** Interruptible Service will be furnished when and where available to those customers that continue to receive their electric supply from Public Service. In the event that a customer taking service under this provision obtains their electric supply from a third party supplier, they will no longer be eligible for this provision upon the initiation of third party supplied service. Further, the customer will be required to pay Public Service, in accordance with Standard Terms and Conditions, Section 15.6, Metering, for the installed interval metering device. Interruptible Service will be furnished under the following conditions:

(i) **Curtailable Electric Service:** Curtailable Electric Service will be furnished when and where available. Those customers that receive electric supply from a third party supplier may continue to receive service under this Special Provision. If a third party supplied customer chooses to no longer participate, or alternatively is disqualified for this Special Provision because of continual failure to meet agreed upon load reductions, the customer will be required to pay Public Service, in accordance with Standard Terms and Conditions, Section 15.6, Metering, for the installed interval metering device. Curtailable Electric Service will be furnished under the following conditions:

(i-1) A customer agrees to take service under this rate schedule at a single service connection and agrees to curtail his load during times of curtailment by the amount stated in his Application/ Agreement. A credit of $6.11 ($6.48 including SUT) per kilowatt of average actual curtailed demand for each curtailment period will be applied to the customer's bill in a succeeding month. The curtailed demands will be measured as the difference, for each hour, between a customer-specific hourly load curve developed by Public Service for customer's normal business operation and the actual recorded hourly load during the curtailment period. The curtailment period will commence a minimum of one hour from the time of notification and end at the time indicated in the restoration call but not later than 8:00 P.M. as indicated in (i-3) below. For each applicable calendar month, the customer's individual curtailment period results will be summed to determine the appropriate credit. There will be no penalty for failure to curtail load or meet the agreed upon load reduction when notified. Continued failure by a customer to meet the agreed upon load reduction, however, will result in customer's disqualification for this Special Provision and Public Service may remove from the customer's premises the interval metering device installed for this Special Provision.

RATE SCHEDULE HTS

SPECIAL PROVISIONS:

(c) **Standby Service:** When Standby Service, as defined in Section 10.2 of the Standard Terms and Conditions, is delivered, the following charges and provisions shall apply:

(c-1) **Standby Service Charge:** Where Public Service must provide reserve capacity and stand ready at all times to deliver electric supply, a standby charge of $1.31 ($1.39 including SUT) per kilowatt of Standby Capacity shall be applied. Where a customer receives electric supply from a third party supplier, that customer will receive a Standby Credit as part of the Energy and Capacity Credits. The Standby Credit is based upon the product of the Standby Capacity times the sum of the Capacity Credit plus the Transmission Credit, pursuant to this Rate Schedule's Section on Energy and Capacity Credits (both in dollars per kilowatt per month), adjusted by the Board of Public Utilities approved coincidence factor of 0.15.

(c-2) **Determination of Standby Capacity:** The standby kilowatt capacity shall be equivalent to the difference between the customer's firm capacity and the total load the customer would require in the event of a failure as determined by Public Service. The total load shall be the equivalent to 85% of the customer's kilovoltampere requirement, as rated by Public Service. The customer may be required to furnish and install, at his own expense, a load-limiting device, approved by Public Service, which shall be maintained by Public Service at customer's expense. The maximum kilovoltampere demand setting of the load-limiting device shall be under the sole control of and be adjusted only by Public Service, and shall not be tampered or interfered with in any way by the customer. At any time that there is an increase in the standby kilowatt capacity, a new term, shall commence; the standby kilowatt capacity may not be revised downward during any term.

(c-3) **Minimum Charge:** In lieu of the minimum charge hereinbefore set forth, the minimum charge in any month shall be the Standby Service Charge less any Interruptible Service Credit if applicable. The waiver of minimum charge is not applicable.

(c-4) **Parallel Operation:** Customer shall not, at any time, operate private plant service in parallel with the service furnished by Public Service except with the written consent of Public Service.

(c-5) **Maintenance Power:** When a FERC Qualifying Facility schedules maintenance with prior notification to and approval from Public Service for maintenance power or in the event of failure of customer's cogeneration or small power production FERC Qualifying Facility, that portion of the customer's monthly maximum demand related to this service will not be subject to the Kilowatt Charges hereinbefore set forth. Where a customer receives electric supply from a third party supplier, the customer will not be subject to the Kilowatt Charges hereinbefore set forth, net of any Capacity and Transmission Credits.

(d) **Interruptible Service :** Interruptible Service will be furnished when and where available to those customers that continue to receive their electric supply from Public Service. In the event that a customer taking service under this provision obtains their electric supply from a third party supplier, they will no longer be eligible for this provision upon the initiation of third party supplied service. Further, the customer will be required to pay Public Service, in accordance with Standard Terms and Conditions, Section 15.6, Metering, for the installed interval metering device. Interruptible Service will be furnished under the following conditions:

(i) **Curtailable Electric Service:** Curtailable Electric Service will be furnished when and where available. Those customers that receive electric supply from a third party supplier may continue to receive service under this Special Provision. If a third party supplied customer chooses to no longer participate, or alternatively is disqualified for this Special Provision because of continual failure to meet agreed upon load reductions, the customer will be required to pay Public Service, in accordance with Standard Terms and Conditions, Section 15.6, Metering, for the installed interval metering device. Curtailable Electric Service will be furnished under the following conditions:

(i-1) A customer agrees to take service under this rate schedule at a single service connection and agrees to curtail his load during times of curtailment by the amount stated in his Application/ Agreement. A credit of $6.11 ($6.48 including SUT) per kilowatt of average actual curtailed demand for each curtailment period will be applied to the customer's bill in a succeeding month. The curtailed demands will be measured as the difference, for each hour, between a customer-specific hourly load curve developed by Public Service for customer's normal business operation and the actual recorded hourly load during the curtailment period. The curtailment period will commence a minimum of one hour from the time of notification and end at the time indicated in the restoration call but not later than 8:00 P.M. as indicated in (i-3) below. For each applicable calendar month, the customer's individual curtailment period results will be summed to determine the appropriate credit. There will be no penalty for failure to curtail load or meet the agreed upon load reduction when notified. Continued failure by a customer to meet the agreed upon load reduction, however, will result in customer's disqualification for this Special Provision and Public Service may remove from the customer's premises the interval metering device installed for this Special Provision.

BUILDING UTILIZATION ELECTRIC SERVICE

APPLICABLE TO:

Customers receiving service under Electric Rate Schedules HTS, LPL and GLP.

CHARACTER OF SERVICE:
Commitments for service under this provision will be made available to qualifying customers until July 31, 1999.

CREDIT:
A credit equal to the customer's total distribution service demand charge(s) for the newly leased or purchased space, as determined by Public Service, will be applied to the customer's monthly electric bills for twelve consecutive billing months. The credit must commence within nine months after receiving written commitment from Public Service for Building Utilization Electric Service. In no case shall application of this Service and the Area Development Service Special Provision of Electric Rate Schedules HTS, LPL or GLP result in a negative charge for demand.

For new customers, the credit shall apply to all kilowatts, as measured by Public Service. A new customer, for purposes of this service, shall be defined as a customer whose newly leased or purchased space is separately metered.

For existing customers, the credit shall apply only to those kilowatts, as measured by Public Service, which are in excess of comparable demands in the same month established in a base year period, which period shall be defined as the twelve calendar months immediately preceding the first months service is provided under Building Utilization Electric Service. An existing customer for purposes of this Service shall be defined as a customer whose newly leased or purchased space is not separately metered from his existing service.

ELIGIBILITY:

Each customer will be required to sign an Application for Building Utilization Electric Service including an estimate of additional demand, and within 90 days of application for electric service. Applicants must submit evidence of a comprehensive energy audit of the customer's facility to Public Service prior to receiving the credit. Upon verification of eligibility, Public Service will provide the customer with a written commitment for Building Utilization Electric Service.

To be eligible, a customer must lease or purchase vacant space for manufacturing, research and development, office or warehousing. The effective date of the lease or purchase must be between August 1, 1992 and July 31, 1999. The total additional leased or purchased building space must equal or exceed 15,000 square feet.

Qualifying building space must be vacant for a minimum of three months, as determined by Public Service, prior to receiving a commitment for Building Utilization Electric Service. The space must require no significant additional investment in facilities by Public Service, defined as 50% of the estimated first year annual distribution service revenue.

THIS PAGE HAS BEEN INSERTED TO INDICATE A BREAK AND INDICATES THE PRESENCE OF A PHYSICAL SEPARATION BETWEEN THE PRECEDING PAGES AND THOSE THAT FOLLOW.

THIS PAGE IS NOT A PART OF THE OFFICIAL RECORD AND IS USED SOLELY FOR CONVENIENCE DURING ELECTRONIC REVIEW

State of New Jersey
DIVISION OF THE RATEPAYER ADVOCATE
31 CLINTON STREET, 11TH FLOOR
P.O. BOX 46005
NEWARK NJ 07101

CHRISTINE TODD WHITMAN
Governor

BLOSSOM A. PERETZ, ESQ.
Ratepayer Advocate and Director

April 1, 1999

In the Matters of Public Service Electric and Gas Company
Restructuring, Stranded Costs and Unbundling Proceedings

BPU Docket Nos.
EO97070463, EO97070462, EO97070461

Via Hand Delivery
Mark Musser, Secretary
Board of Public Utilities
Two Gateway Center
Newark, New Jersey 07102

Dear Secretary Musser:

On March 30, 1999, the Division of the Ratepayer Advocate, along with the New Jersey Business Users, the New Jersey Industrial Customers Group, the Mid-Atlantic Power Supply Association, New Energy Ventures, Inc., and the New Jersey Public Interest Intervenors (except for the NRDC), filed a proposed Joint Stipulation of Settlement (the "Better Choice Settlement Proposal") in the above-referenced matter. It has come to our attention that, due to a clerical error, one page of Attachment B (Table 3) was inadvertently omitted. Therefore, we are filing a copy of Table 3 of Attachment B herewith, and simultaneously serving copies on all parties.

Very truly yours,

Blossom A. Peretz, Esq.
Ratepayer Advocate

By: Gregory Eisenstark
Gregory Eisenstark, Esq.
Deputy Ratepayer Advocate

Encl.
c: Hon. Herbert H. Tate, President
Hon. Carmen J. Armenti, Commissioner
Hon. Frederick Butler, Commissioner
Service List

Tel: (973) 648-2690 • Fax: (973) 624-1047 • Fax: (973) 648-2193 • Modem Tel: (973) 648-3084
http://www.njin.net/rpa E-Mail: njratepayer@rpa.state.nj.us

Table 3: Implicit MTC / Retail Adder Value Stream:										
		Monthly	Shopping Customers		Residual Value (to August '03)	Pre-Tax	Net Value	After-Tax IMPLICIT MTC & Retail Adder (NPV)		
MONTH	YEAR	Wires Sales	% Shop	Shopping kWh	Bundled Rate after Rate cut minus sum:	Adder	Stream	Total NPV MTC	Retail Adder	TOTAL
					STC, NTC, SBC, Shopping Credit	Retained	on non	$ (307,240,706)	$ 361,876,649	$ 54,635,943
					Distribution and TEFA, CBT	by PSEG	shoppers			
August	1999	3,256,283,417	5%	162,814,171	$ 0.0118	$ 0.0069	$ 0.0188	$ 21,562,434	$ 12,646,102	$ 34,208,536
September	1999	3,259,268,343	5%	162,963,417	$ 0.0118	$ 0.0069	$ 0.0188	$ 21,590,048	$ 12,657,695	$ 34,247,743
October	1999	3,262,256,006	5%	163,112,800	$ 0.0118	$ 0.0069	$ 0.0188	$ 21,617,688	$ 12,669,297	$ 34,286,986
November	1999	3,265,246,407	5%	163,262,320	$ 0.0118	$ 0.0069	$ 0.0188	$ 21,645,354	$ 12,680,911	$ 34,326,265
December	1999	3,268,239,550	5%	163,411,978	$ 0.0118	$ 0.0069	$ 0.0188	$ 21,673,044	$ 12,692,535	$ 34,365,579
January	2000	3,271,235,436	30%	981,370,631	$ (0.0048)	$ 0.0051	$ 0.0003	$ (8,809,875)	$ 9,360,967	$ 551,092
February	2000	3,274,234,068	30%	982,270,220	$ (0.0048)	$ 0.0051	$ 0.0003	$ (8,793,081)	$ 9,369,548	$ 576,467
March	2000	3,277,235,449	30%	983,170,635	$ (0.0048)	$ 0.0051	$ 0.0003	$ (8,776,272)	$ 9,378,137	$ 601,865
April	2000	3,280,239,581	30%	984,071,874	$ (0.0048)	$ 0.0051	$ 0.0003	$ (8,759,448)	$ 9,386,734	$ 627,286
May	2000	3,283,246,467	30%	984,973,940	$ (0.0048)	$ 0.0051	$ 0.0004	$ (8,742,608)	$ 9,395,338	$ 652,730
June	2000	3,286,256,110	30%	985,876,833	$ (0.0047)	$ 0.0051	$ 0.0004	$ (8,725,752)	$ 9,403,950	$ 678,198
July	2000	3,289,268,511	30%	986,780,553	$ (0.0047)	$ 0.0051	$ 0.0004	$ (8,708,882)	$ 9,412,571	$ 703,689
August	2000	3,292,283,674	30%	987,685,102	$ (0.0047)	$ 0.0051	$ 0.0004	$ (8,691,995)	$ 9,421,199	$ 729,204
September	2000	3,295,301,601	30%	988,590,480	$ (0.0047)	$ 0.0051	$ 0.0004	$ (8,675,093)	$ 9,429,835	$ 754,742
October	2000	3,298,322,294	30%	989,496,688	$ (0.0047)	$ 0.0051	$ 0.0004	$ (8,658,176)	$ 9,438,479	$ 780,303
November	*2000*	*3,301,345,756*	30%	*990,403,727*	*$ (0.0047)*	*$ 0.0051*	*$ 0.0004*	$ (8,641,243)	$ 9,447,131	$ 805,888
December	2000	3,304,371,990	30%	991,311,597	$ (0.0047)	$ 0.0051	$ 0.0004	$ (8,624,295)	$ 9,455,791	$ 831,496
January	2001	3,307,400,998	40%	1,322,960,399	$ (0.0046)	$ 0.0044	$ (0.0003)	$ (8,607,331)	$ 8,112,393	$ (494,938)
February	2001	3,310,432,782	40%	1,324,173,113	$ (0.0046)	$ 0.0044	$ (0.0003)	$ (8,590,352)	$ 8,119,830	$ (470,522)
March	2001	3,313,467,345	40%	1,325,386,938	$ (0.0046)	$ 0.0044	$ (0.0002)	$ (8,573,357)	$ 8,127,273	$ (446,084)
April	2001	3,316,504,690	40%	1,326,601,876	$ (0.0046)	$ 0.0044	$ (0.0002)	$ (8,556,346)	$ 8,134,723	$ (421,624)
May	2001	3,319,544,819	40%	1,327,817,928	$ (0.0046)	$ 0.0044	$ (0.0002)	$ (8,539,320)	$ 8,142,180	$ (397,141)
June	2001	3,322,587,735	40%	1,329,035,094	$ (0.0046)	$ 0.0044	$ (0.0002)	$ (8,522,279)	$ 8,149,643	$ (372,635)
July	2001	3,325,633,440	40%	1,330,253,376	$ (0.0046)	$ 0.0044	$ (0.0002)	$ (8,505,221)	$ 8,157,114	$ (348,108)
August	2001	3,328,681,937	40%	1,331,472,775	$ (0.0058)	$ 0.0044	$ (0.0014)	$ (10,847,911)	$ 8,164,591	$ (2,683,320)
September	2001	3,331,733,229	40%	1,332,693,292	$ (0.0058)	$ 0.0044	$ (0.0014)	$ (10,832,985)	$ 8,172,075	$ (2,660,910)
October	2001	3,334,787,318	40%	1,333,914,927	$ (0.0058)	$ 0.0044	$ (0.0014)	$ (10,818,046)	$ 8,179,566	$ (2,638,480)
November	2001	3,337,844,206	40%	1,335,137,682	$ (0.0058)	$ 0.0044	$ (0.0014)	$ (10,803,093)	$ 8,187,064	$ (2,616,029)
December	2001	3,340,903,897	40%	1,336,361,559	$ (0.0058)	$ 0.0044	$ (0.0014)	$ (10,788,127)	$ 8,194,569	$ (2,593,558)
January	2002	3,343,966,392	40%	1,337,586,557	$ (0.0058)	$ 0.0044	$ (0.0014)	$ (10,773,146)	$ 8,202,081	$ (2,571,065)
February	2002	3,347,031,695	40%	1,338,812,678	$ (0.0057)	$ 0.0044	$ (0.0014)	$ (10,758,152)	$ 8,209,599	$ (2,548,553)
March	2002	3,350,099,807	40%	1,340,039,923	$ (0.0057)	$ 0.0044	$ (0.0013)	$ (10,743,144)	$ 8,217,125	$ (2,526,020)
April	2002	3,353,170,732	40%	1,341,268,293	$ (0.0057)	$ 0.0044	$ (0.0013)	$ (10,728,123)	$ 8,224,657	$ (2,503,466)
May	2002	3,356,244,472	40%	1,342,497,789	$ (0.0057)	$ 0.0044	$ (0.0013)	$ (10,713,089)	$ 8,232,196	$ (2,480,891)
June	2002	3,359,321,029	40%	1,343,728,412	$ (0.0057)	$ 0.0044	$ (0.0013)	$ (10,698,038)	$ 8,239,743	$ (2,458,295)
July	2002	3,362,400,407	40%	1,344,960,163	$ (0.0057)	$ 0.0044	$ (0.0013)	$ (10,682,976)	$ 8,247,296	$ (2,435,680)
August	*2002*	3,365,482,607	40%	1,346,193,043	*$ (0.0114)*	*$ 0.0044*	*$ (0.0070)*	*$ (21,396,914)*	$ 8,254,856	$ (13,142,058)
September	2002	3,368,567,633	40%	1,347,427,053	$ (0.0113)	$ 0.0044	$ (0.0070)	$ (21,391,658)	$ 8,262,423	$ (13,129,235)
October	2002	3,371,655,487	40%	1,348,662,195	$ (0.0113)	$ 0.0044	$ (0.0069)	$ (21,386,398)	$ 8,269,997	$ (13,116,401)
November	2002	3,374,746,171	40%	1,349,898,468	$ (0.0113)	$ 0.0044	$ (0.0069)	$ (21,381,133)	$ 8,277,577	$ (13,103,555)
December	2002	3,377,839,688	40%	1,351,135,875	$ (0.0113)	$ 0.0044	$ (0.0069)	$ (21,375,863)	$ 8,285,165	$ (13,090,697)
January	2003	3,380,936,041	50%	1,690,468,021	$ (0.0082)	$ 0.0037	$ (0.0045)	$ (15,482,349)	$ 6,910,633	$ (8,571,716)
February	2003	3,384,035,232	50%	1,692,017,616	$ (0.0082)	$ 0.0037	$ (0.0045)	$ (15,471,672)	$ 6,916,968	$ (8,554,704)
March	2003	3,387,137,264	50%	1,693,568,632	$ (0.0082)	$ 0.0037	$ (0.0045)	$ (15,460,985)	$ 6,923,309	$ (8,537,677)
April	2003	3,390,242,140	50%	1,695,121,070	$ (0.0081)	$ 0.0037	$ (0.0045)	$ (15,450,288)	$ 6,929,655	$ (8,520,633)
May	2003	3,393,349,862	50%	1,696,674,931	$ (0.0081)	$ 0.0037	$ (0.0045)	$ (15,439,582)	$ 6,936,007	$ (8,503,574)
June	2003	3,396,460,433	50%	1,698,230,217	$ (0.0081)	$ 0.0037	$ (0.0045)	$ (15,428,865)	$ 6,942,365	$ (8,486,500)
July	2003	3,399,573,855	50%	1,699,786,928	$ (0.0081)	$ 0.0037	$ (0.0044)	$ (15,418,139)	$ 6,948,728	$ (8,469,410)

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THE BETTER CHOICE SETTLEMENT PROPOSAL

In the Matters of Public Service Electric and Gas Company
Restructuring, Stranded Costs and Unbundling Proceedings

BPU Docket Nos.
EO97070463, EO97070462, EO97070461

Mark Musser, Secretary
Board of Public Utilities
Two Gateway Center
Newark, New Jersey 07102

Dear Secretary Musser:

This letter is submitted on behalf of the Mid Atlantic Power Supply Association ("MAPSA"), New Jersey Business Users, the New Jersey Industrial Customers Group, New Jersey Public Interest Intervenors (with the exception of the Natural Resources Defense Council) and New Energy Ventures, Inc., to advise the Board of Public Utilities that the undersigned parties join in the Joint Stipulation of Settlement in the above-captioned Stranded Cost, Restructuring and Unbundling proceedings that has been filed today under separate covers by the Division of the Ratepayer Advocate.

As indicated in the document, the Better Choice Settlement Proposal presents a balanced and internally consistent resolution of the major issues presented in this proceeding; considers the impact of recent market evidence; and, most importantly, takes full account of the pro-competition mandates of the Energy Competition Act.[1] The parties are confident that the Board

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[1] The positions contained in the filing represent the views of the groups listed above but should not necessarily be attributed to particular members of any group with respect to any specific issue. The material portions of the Better Choice Settlement Proposal are supported by sworn affidavits which are attached as Attachments C - F of the Stipulation. The Better Choice Settlement Proposal is a proposed compromise submitted by the parties and does not necessarily represent their litigation positions.

can implement the Better Choice alternative without delaying the initiation of retail choice or the statutorily mandated rate decreases.

The Better Choice Settlement Proposal is supported by representatives of the great majority of consumers and all of the party-suppliers who presently hope to be able to serve residential customers in PSE&G's service territory. We sincerely believe that the Better Choice Settlement Proposal is the Board's only real choice if it wishes to establish restructuring rules that have any chance of creating vibrant competition to benefit PSE&G customers and New Jersey for years to come.

As the Stipulation itself indicates, the parties are requesting that the Board reject the PSE&G Settlement as not in the public interest and adopt the Better Choice Settlement Proposal after appropriate development of an evidentiary record.

Very Truly Yours,

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cc: Hon. Herbert H. Tate, President
Hon. Carmen J. Armenti, Commissioner
Hon. Frederick Butler
Service List

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STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY UNBUNDLED RATES FILING	:	OAL Docket No. PUC7347-97 BPU Docket No. E097070461
IN THE MATTER OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY STRANDED COST FILING	:	OAL Docket No. PUC7348-97 BPU Docket No. E097070462
IN THE MATTER OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY RESTRUCTURING FILING	:	OAL Docket No. PUC7349-97 BPU Docket No. E097070463

JOINT STIPULATION OF SETTLEMENT OF STRANDED COSTS
RESTRUCTURING AND UNBUNDLING PROCEEDINGS
"BETTER CHOICE SETTLEMENT PROPOSAL"

The New Jersey Division of the Ratepayer Advocate ("Ratepayer Advocate"), the New Jersey Business Users, the New Jersey Industrial Customers Group, the Mid Atlantic Power Supply Association ("MAPSA"), New Energy Ventures, Inc., and the New Jersey Public Interest Intervenors (except for the NRDC) ("NJPII"), all parties in the above captioned proceedings, hereby submit to the Board of Public Utilities ("Board") this Stipulation of Settlement and request that: 1) the Board **reject** the Stipulation filed by Public Service Electric & Gas ("PSE&G") and a few other parties ("the PSE&G Settlement") as not in the public interest: and 2) **adopt** as its Final Order the terms incorporated in the Term Sheet (Attachment "A") (hereinafter referred to as the "**Better Choice Settlement Proposal**") as a reasonable compromise of the positions of the various parties in a manner consistent with the public interest.

<u>Summary of Better Choice Settlement Proposal</u>

In contrast to the PSE&G Settlement, the **Better Choice Settlement Proposal** is a comprehensive, fair and balanced attempt to resolve the competing issues raised in these cases. The **Better Choice Settlement Proposal** provides: approximately $900 million in <u>sustained</u> rate reductions to customers in years 5 and 6; a substantial opportunity for PSE&G to recover the same amount of stranded costs as identified in its proposal, with an appropriate level of securitization, and without impairing the financial health of the Company; and customer shopping credits which will allow the development of a vibrant competitive energy market, producing billions of dollars of savings for PSE&G customers and ensuring that New Jersey will be "open for business" on the same terms as neighboring states that have already implemented electric retail choice. In contrast, the customer shopping credits proposed in PSE&G's settlement are far lower than those established for PECO Energy in neighboring Pennsylvania, when those credits are adjusted to reflect current and New Jersey specific cost factors. PSE&G's proposed credits would severely limit real customer choice in PSE&G's service territory, clearly at odds with the pro-competition policy of the State expressed in the Act.

The **Better Choice Settlement Proposal** is a financially cohesive and internally consistent plan which would allow the Board to move forward expeditiously to ensure that full retail access will be available to consumers starting on August 1, 1999, as required by the New Jersey Electric Discount and Energy Competition Act[1] (the "Act" or "Energy Competition Act"). Adoption of

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[1] P.L. 1999 c.23.

PSE&G's Stipulation and Settlement, by contrast, is not in the public interest, and will not implement the stated goals of the Act.

The essential elements of the **Better Choice Settlement Proposal** plan for restructuring are as follows:

- Provides the rate decreases from current rates mandated by the Energy Competition Act for PSE&G (13.9% by August, 2002), but **guarantees** those discounts rather than having them be contingent upon securitization, and ensures that they will be sustainable.

- Utilizes accounting expense reductions that PSE&G would otherwise keep under its proposal to offset and eliminate the bill increases that PSE&G's plan appears to contemplate at the end of the 4 year transition period, thereby providing for approximately $900 million in sustained rate relief to customers and sustaining the reductions for at least two additional years; providing greater rate discounts than those minimally required by the Act; and providing significant additional benefits to New Jersey consumers, without harm to the financial integrity of the Company.

- Provides the Company with a fair opportunity to recover **<u>the same amount</u>** of stranded costs as identified in the PSE&G proposal, recognizing the Company's future mitigation opportunities and responsibilities under the Act. The **Better Choice Settlement Proposal** would permit PSE&G to recover from specific charges or foregone rate refunds over ***<u>$2.8 billion</u>*** in stranded costs **with over $2.5 billion (including issuance costs) securitized and the remainder recovered from its significant future mitigation opportunities**. The **Better Choice Settlement Proposal** also includes a stranded cost offset which recognizes that, based upon recent marketplace valuations of generation assets, the generation plants that are being transferred to PSE&G's newly formed affiliate are worth more than the low book value claimed by PSE&G.[2] The financial details of the **Better Choice Settlement Proposal** are set forth in Attachment "B" hereto and show unbundled rate elements and customer shopping credits that will give PSE&G the opportunity to recover the levels of stranded costs and other elements proposed by the **Better Choice Settlement Proposal**, together with all appropriate taxes. The ability to provide the same level of stranded cost recovery opportunity and still establish greater rate decreases and pro-competitive shopping credits under the **Better Choice Settlement Proposal** demonstrates that the PSE&G Settlement will provide the Company with levels of earnings and revenue opportunities that are above those necessary to keep the utility financially healthy in the transition to competition.

- Allows for customer shopping credits that truly encourage a competitive market to develop, as opposed to the inadequate shopping credits that are found in the PSE&G proposed Settlement. Recent market evidence demonstrates clearly that shopping credits must be robust enough to permit suppliers to offer value to customers, i.e., savings over that which the customer is paying in regulated rates. The **Better Choice Settlement Proposal** contains shopping credits that will allow residential customers to consider offers that will save them an additional 5-7% on their electric bills. Without customer shopping

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[2] The Better Choice Settlement Proposal concedes to PSE&G, as part of the agreement to settle, the transfer of other assets to the GENCO, which are discussed infra, and which include power and fuel contracts, real estate, goodwill, and the like. These assets have not been fully identified in its proposed Stipulation.

credits that will allow suppliers to offer savings to all customers, **competition in the entire PSE&G marketplace, and especially for residential and small commercial customers, will be severely limited for years to come.**

The PECO Energy service territory in Pennsylvania is the only area in which a vibrant competitive residential marketplace has emerged as a result of restructuring. The **Better Choice Settlement** proposes shopping credits which closely approximates the shopping credits in the PECO Energy service territory, after accounting for New Jersey specifics and cost differences that have occurred since those credits were established. The following chart illustrates this:[3]

	PECO System Average	PECO Residential Consumers
PECO Updated Shopping Credit (year 2000) (updated for NJ specific costs and cost increases in the wholesale market)	5.51¢/kWh	6.47
PSE&G Proposed Shopping Credit	5.03	5.86
Better Choice Plan Shopping Credit	5.40	6.28

Thus, the shopping credits proposed by the **Better Choice Settlement Proposal** represent the absolute minimum that should be established if the Board wishes to fulfill the mandate of the Act to create a robust, vigorous and permanent competitive market for electric generation services in New Jersey.

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3 These calculations are supported in Attachment "D," Affidavit of John S. Rohrbach. This analysis, as well as all of the other factual averments not otherwise contained in the record are supported by affidavits included as Attachments C-F to this Stipulation.

- The **Better Choice Settlement Proposal** includes important competitive safeguards and other mandated protections to assure that, when the market opens, there will be a level playing field for competitors. Importantly, the proposed Better Choice Settlement includes a detailed GENCO Code of Conduct to reflect the necessary protections for customers and the market if PSE&G is permitted to transfer its assets to an unregulated, separate affiliate (Attach. "A," App. 1). It also contains provisions assuring that an Affiliate Code of Conduct dealing with relations between utilities and their affiliates will be promptly issued by the Board and applied to PSE&G, as well as requiring pro-competitive supplier tariff rules, uniform statewide rules for customer switching of their third party suppliers, and appropriate rules for billing for generation supply and related issues.

- The **Better Choice Settlement Proposal** also insures that PSE&G will cooperate with municipalities and counties that are seeking load data necessary for development of RFPs for municipal aggregation.

Summary of PSE&G's Proposed Stipulation

The PSE&G proposed Settlement, in contrast:

- Provides only a promise of the minimum rate cuts required by the Act[4]. These rate cuts are not guaranteed even at the statutorily mandated amounts, since all reductions, except the first 5% decrease in August of this year, are conditioned on the Company being able to actually issue

[4] Indeed, as discussed in this document, the rate cuts provided for in the PSE&G proposed stipulation may not even meet the minimum requirements of the Act.

securitized bonds. Further, under the PSE&G proposal, the rate decreases abruptly vanish after the year 2003 and customers could find themselves shocked by hefty bill increases of 10% or more due to the elimination of temporary "credits."[5] The commencement of the recovery of deferred costs provided for in PSE&G's proposal could increase the bill impacts <u>even more</u>.

- PSE&G's proposal also would guarantee the utility hundreds of millions of dollars of stranded cost recovery from ratepayers above securitization amounts in an expedited period (four years), without taking into account significant cost or expense reductions that have already occurred and without recognizing the value to PSE&G of transferring its generating assets to a separate unregulated affiliate. What is more, PSE&G's proposed settlement contains no requirement or incentive for PSE&G to try to further mitigate its stranded costs, contrary to the clear requirements of the Act[6], as it allows the Company to keep 100% of these significant potential savings.

- As noted, the PSE&G proposal grants the pre-approval of the transfer to an unregulated affiliate of <u>all</u> of PSE&G's generation assets, as well as other items of value, including power and fuel contracts, real estate and good will, without a line item breakout, valuation, or detailed plan, and without any record support. While the signatories of the **Better Choice Settlement Proposal** will concede these items to PSE&G if a settlement is otherwise achieved, their value must be

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5 These figures are estimates. The Company did not provide a detailed system, year by year proof of revenues that would allow a precise calculation. As noted below, it is not indicated whether PSE&G plans to make the securitization savings permanent. <u>See</u>, Attachment D, Aff. of John S. Rohrbach.

6 <u>See</u>, P.L. 1999 c.23 Sections 2.c. (4) and 13 (f).

recognized if there is no settlement. Many of these items were not valued in the litigated proceedings and if properly valued could provide substantial mitigation of stranded costs.

- Most distressingly, the PSE&G settlement establishes "customer shopping credits" which are far below the levels established for PECO Energy, the company with the shopping credits that have produced one of the most vibrant electric retail markets to date. PSE&G's proposed shopping credits are simply inadequate when New Jersey specific costs and increases in the marketprice of power are considered.

The Board's overriding obligation is to assure that the restructuring of PSE&G is in the public interest and is completed in a manner that best promotes the goals of the Energy Competition Act (not yet in place at the time of the OAL hearings) without impairing the financial integrity of the Company. The attached Term Sheet (Attachment "A") represents a compromise resolution of the positions of the undersigned, and not necessarily their litigation positions, and is presented as a balanced and internally consistent compromise on the major issues presented in this proceeding.

Well established principles of due process and administrative law prevent the Board from adopting a partial settlement, such as either the **Better Choice Settlement Proposal** or the PSE&G proposed settlement, without giving all parties notice and an opportunity to be heard, and assuring that all aspects of the plan are supported by substantial evidence, consistent with controlling law and are in the public interest.[7] The undersigned parties respectfully request that the Board develop

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[7] In a contested case such as this one, the Board must give the parties notice and an opportunity to be heard which comports with the requirements of due process, see, N.J.S.A. 52:14B-9; Where material facts are in dispute, as here, due process (continued...)

an evidentiary record on contested issues, as is required by due process and fairness, and, after a record is developed, enter an order adopting the **Better Choice Settlement Proposal** as its decision in these cases.[8]

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[7](...continued)

requires a full evidentiary hearing, see, e.g., Ufheil Construction Company, Inc. v. Borough of Oradell, 123 N.J. Super. 268, 273; 302 A.2d 533 (1973) ("When an administrative agency . . . is called upon to act quasi-judicially, due process requires that a hearing be held on notice to the parties in interest and that they be given an opportunity to present relevant evidence in support of, or in opposition to, the specific application involved."); Bally Manufacturing Corporation v. New Jersey Casino Control Commission, 85 N.J. 325, 426 A.2d 1000 (1981), *appeal dismissal* 454 U.S. 804 (1981). The Board cannot adopt a partial settlement if the terms of that settlement are not supported by substantial record evidence, see, Mobil Oil Corporation v. Federal Power Commission, 417 U.S. 283 (1974) (FPC could not approve settlement proposal joined by large majority of interested parties and supported by FPC staff unless the FPC found that its terms were in the public interest and supported by substantial evidence; independent investigation consisting of review of the massive record enabled FPC to adopt settlement); In the Matter of Public Service Electric and Gas Company, 304 N.J.Super. 247; 699 A.2d 1224 (1997), *cert. denied* 152 N.J. 12; 702 A.2d 351 (The Appellate Division held that Board of Regulatory Commissioners could adopt stipulated figures in rate case so long as the Board determined that its terms were supported by the record and that the end result complied with the statutory requirements.) Since both the PSE&G and the **Better Choice Settlement Proposal** contain numerous aspects that were not discussed or supported in the record of the proceedings (such as the GENCO transfer, the level of shopping credit necessary to foster a robust competitive marketplace, and the extent to which the entire plan is consistent with the Energy Competition Act not in place at the time of the hearings), before either plan is adopted by the Board it will be necessary to develop a record on the settlement proposals and an opportunity to be heard to all non-settling parties. If a full settlement of all the parties were to emerge, however, additional evidentiary development would not necessarily be required.

[8] The issues should be identified and focused with detail so that the hearing by the Commissioners can be expeditious – without slipping the August 1 date for the start of retail competition.

Detailed Description of Better Choice Settlement Proposal

Rather than simply criticizing the PSE&G proposal, the signatories to the attached **Better Choice Settlement Proposal** have put forth a comprehensive, carefully crafted and fair plan, that is demonstrated to be financially workable, as a means of resolving the PSE&G stranded cost, restructuring and rate unbundling proceedings. Each of the undersigned parties that has joined in this Stipulation agrees that it would accept an order by the Board that included the terms set forth in the attached Term Sheet.[9]

(a) Rate Discounts. The **Better Choice Settlement Proposal**, consistent with the requirements of the Energy Competition Act, would require PSE&G to reduce its overall rates according to the following schedule (reductions are cumulative):

August 1, 1999 - 5% reduction from current rates;

January 1, 2000 - 7.0% reduction from current rates (assumes 3% reduction from securitization; any additional reduction over 3% resulting from securitization would be passed through to customers);[10]

August 1, 2001 - 8.25% reduction from current rates; and

August 1, 2002 - 13.9% reduction from current rates.

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9 Attach. "A." As indicated in the Term Sheet, the parties reserve the right to object to changes to the Term Sheet and reserves the right to pursue all available legal remedies if the Board makes any changes.

10 For the purpose of achieving a settlement, the rate reductions established by the **Better Choice Settlement Proposal** conform with those included in PSE&G's proposed settlement. There is some question, however, about whether the prefunding of 1% of the securitization savings, as part of the initial 5% rate reduction, meets the requirements of section 14.a of the Energy Competition Act.

These rate discounts are **not** contingent on securitization, as is proposed in the PSE&G Stipulation.[11] On the contrary, these rate discounts reflect guaranteed minimums, and, consistent with the Act, savings from securitization will be passed on as further rate reductions.[12]

(b) Avoidance of Rate Shock After Year 4. Under PSE&G's plan, the rate decreases are going to be reflected in a separate transition rate credit or a negative "Market Transition Charge" (MTC).[13] When PSE&G's proposed negative MTC or special rate credit is eliminated starting in year 5, rates would return almost to their present level by 10% or possibly more.[14] The **Better Choice Settlement Proposal** completely mitigates this almost certain "rate shock" by applying the following cost reductions as offsets to the rate increases, and producing $750 million to $914 billion[15] in additional rate cuts to PSE&G customers:.

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11 See, PSE&G Settlement Proposal p. 3, ¶ (1)(b). All rate decreases but the first 5% rate decrease are made specifically contingent on the ability of PSE&G to actually issue securitized bonds and establish an "STC."

12 P.L. 1999 c.23, Section 4.d.

13 See Attach. "D," Aff. of John S. Rohrbach, pgs. 4-5.

14 Rates would increase by the higher amounts if the Company does not continue to pass through the savings from securitization. Nowhere in PSE&G's proposal does the Company indicate that the savings from securitization will be reflected as a permanent rate decrease to customers. As noted, because PSE&G did not submit a proof of revenue for years 5 and 6 or prior years these are the estimated rate impacts in those years.

15 See Attach. "D," Aff. of John S. Rohrbach, pg. 4. The range takes account of the fact that SBC and NTC amortization amounts may be lower, but, just as in the PSE&G settlement, deferrals from the 4 year transition may need to be collected from ratepayers after the transition period.

1) PSE&G has indicated that its distribution depreciation reserve is overfunded by $569 million. The **Better Choice Settlement Proposal** uses approximately 60% of this over funding to offset the rate increases in years 5 and 6.

2) The **Better Choice Settlement Proposal** uses the value of expired amortizations still included in rates ($35 million) to offset rate increases;

3) The **Better Choice Settlement Proposal** uses $90 million of Salem related stranded costs as reflected in the PSE&G proposal to further offset rate increases;

4) The **Better Choice Settlement Proposal** uses $90 million (after tax) overcollection in the Levelized Energy Adjustment Clause (LEAC) as of July 31, 1999. [16]

Failure to recognize these cost reductions means that PSE&G's rates would be overstated by approximately $900 million (grossed up for taxes), all of which will flow to PSE&G under its own proposed stipulation. The **Better Choice Settlement Proposal** uses a portion of PSE&G's rate credits to eliminate the rate hikes that would otherwise hit ratepayers after the 48 month transition period.

In addition, the **Better Choice Settlement Proposal** suggests that PSE&G's rates should stay at these reduced levels in year 7 and thereafter unless PSE&G can prove that it needs to increase its rates through a rate case proceeding.[17]

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[16] Unlike the amount included in the PSE&G settlement, this figure is based based upon the January 31, 1999 balance and the growth of that amount during that month. The appropriate way in which to deal with this issue is to true-up the actual deferral as of July 30, 1999.

[17] In contrast, the PSE&G proposed Settlement offers no mitigation of sudden bill increases which could appear in year 5, while PSE&G's shareholders would (continued...)

(c) Rate Design/Cost of Service. The rate decreases would be allocated to recognize the impact of the 1998 Demand Side Adjustment Factor ("DSAF") increases, in connection with the PSE&G rate design. Transition bond charges would be grossed up and collected via a per kWh charge to reflect the manner in which the revenue requirement associated with generation assets currently is being collected. This portion of the **Better Choice Settlement Proposal** is consistent with the PSE&G proposal and ensures that all customers receive the same rate reductions among and between rate classes.

(d) Rate Unbundling. The **Better Choice Settlement Prposal** reduces distribution rates by $20 million to reflect current risk adjusted cost of capital, and reduces the average distribution rate from 2.08¢ to 2.03¢. This portion of the **Better Choice Settlement Proposal** reflects the PSE&G proposed settlement.

(e) Stranded Costs and Securitization. A key element of the **Better Choice Settlement Proposal** is its balanced and fair approach to PSE&G's stranded cost recovery and securitization.

[17](...continued)
receive the full benefit of the distribution depreciation reserve amortization and the expired amortizations.

Stranded cost recovery opportunities would be as follows:

PSE&G Total Stranded Costs	$3.3 billion[18]
Securitized Amount with allowance for issuance costs[19]	$2.540 billion[20]
Contribution From Implicit Retail Adder	$54.6 million[21]
Distribution Depreciation Amortization	$170.35 million
Genco Transfer Premium	$600 million

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18 The PSE&G proposal finds that it has $3.3 billion in stranded costs but claims to allow the Company the opportunity to collect only $3.075 billion. PSE&G Settlement Proposal, p. 8, ¶ 10. In fact, with issuance costs ($125 million), the Company will be able to collect $3.2 billion.

19 There is a significant question about whether the Act permits securitization at the $2.475 billion level. Section 14.C(1) states that a utility may securitize up to 75% of its total "recovery eligible utility generation stranded cost." Recovery eligible stranded costs are to be quantified by the Board after recognizing mitigation and the transfer values from asset sales or divestitures. See P.L. 1999 c. 23, Sections 13c. and f. If the Board reads the statute in this way, PSE&G would only be permitted to securitize its stranded costs after deducting recoveries via mitigation (including, at least the $600 million transfer premium), and future mitigation amounts, and the remainder would have to be recovered in an MTC.

20 PSE&G has proposed to include $125 million as bond issuance and transaction costs. PSE&G Stip. ¶ 11(a). Under the Better Choice Settlement Proposal, PSE&G would be permitted to collect an amount for issuance and transaction costs, representing one-half of any actual, verified level, not to exceed $62.5 million. The terms of the bonds and the method of collection of transition bond charges would be identical to that proposed by PSE&G. Taxes associated with the transition bonds, however would be collected only through a separate Tax MTC, and only to the extent they are actual and verifiable, subject to periodic true-up.

21 The stranded cost contribution from the implicit retail adder is explained in more detail on page 15, below.

Non-credited Cost Reductions	$ 43 million
Mitigation Opportunities	$828 million
Total	$4.23 billion

While the stated level of stranded cost is identical to the amount indicated in the PSE&G Stipulation, the **Better Choice Settlement Proposal** would require PSE&G to fund the unsecuritized portion of this amount through recognition of the actual value of the transfer of the Company's generation assets and other related assets to an unregulated affiliate as well as through mitigation cost savings and non-credited cost reductions.[22]

Genco Transfer Value

The PSE&G proposed Settlement states that the Genco transfer value will be determined by subtracting the proposed level of stranded costs ($3.3 billion) from the net after tax book value of the assets ($5.1 billion) plus the $600 million that the Genco would pay to PSE&G in advance of the utility's collection of these funds through the "MTC," for a total of $2.368 billion.[23] This calculation appears to recognize that the Company's generating assets are worth at least $600 million more than the net after tax book value, after accounting for stranded costs. **It is important**

22 As stated previously, for the purposes of settlement, the signatories to the **Better Choice Settlement Proposal** will concede the transfer of the related assets to the GENCO, notwithstanding the fact that they have neither been itemized nor valued. These items, which include the transfer of real estate which could be used for siting additional plants and good will, could justify the imposition by the Board of a substantial transfer premium.

23 PSE&G Stip., Attach. 4.

to note however that PSE&G's proposed stipulation provides for the utility to repay the $600 million to the Genco as it is collected through the MTC. Thus, the actual transfer value under PSE&G's proposed settlement is only $1.8 billion. In contrast, and as the attached affidavit demonstrates, a reasonable market value of PSE&G's transferred generation assets is $2.9 billion.[24] Thus, considering recent market evidence, PSE&G's generating assets have a value that is considerably higher than that which is implicit in the "administratively determined" stranded costs claim reflected in the PSE&G's Settlement and justifies recognition of a market value adder, i.e., a transfer premium. But the transfer premium or market value adder is not properly credited to ratepayers by PSE&G's referencing of the $600 million "MTC" because the MTC is an amount that ratepayers will pay rather than a credit for this additional market value. As Mr. Dirmeier explains, PSE&G is guaranteed virtually 100% recovery of the $600 million MTC by allowing PSE&G to keep 100% of its excess distribution depreciation reserve and through the retention of the retail adder for non-shopping customers.[25]

Thus, while the PSE&G proposed settlement appears to acknowledge that the fair value of the assets transferred to Genco is $600 million greater than the nominal net book value less assumed stranded costs, it recognizes this higher value, not by an offset to stranded costs, but

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[24] Attach. "C," Aff. of Michael D. Dirmeier. While the transfer will not cause PSE&G to realize tax gains as losses overall, even if one assumed a real sale, the net after tax proceeds are estimated by Mr. Dirmeier to be at least $2.4 billion. Id.

[25] Id. at 3-4.

through a string of MTC payments to be made by ratepayers and from foregone future rate reductions.[26]

The **Better Choice Settlement Proposal**, in contrast, reduces PSE&G's MTC to zero, thereby actually giving to ratepayers the additional market value for the assets transferred, not an illusory recognition of a payment they themselves will make.[27]

Other Sources of Stranded Cost Funding

In addition to the $600 million market value, the other sources of recovery opportunity for non-securitized stranded costs recognized in the **Better Choice Settlement Proposal** are as follows:

> (1) *Distribution Depreciation Reserve Amortization.* PSE&G has indicated that its depreciation reserve is in excess of the amount required by $569 million.[28] The Company proposes to retain the entire balance by applying it towards its "opportunity" to recover non-securitized stranded costs.[29] Since ratepayers fully funded this excess reserve, a legitimate case can be made that 100% of these dollars should be returned to ratepayers in the form of credits. The **Better Choice Settlement Proposal** proposes that PSE&G be

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26 Id. See also Attach. "F," Aff. of James B. Rouse on behalf of Praxair, Inc.

27 The **Better Choice Settlement Proposal** is also superior to PSE&G's because it reduces the rate uncertainty for customers by correctly valuing assets transferred to the unregulated Genco affiliate and eliminating the need for true-ups of the MTC. PSE&G will also have greater revenue certainty if a true-up is "not required." Under PSE&G's plan the Genco transfer is undervalued, and under the Energy Competition Act, the MTC would need to be trued up to properly reflect the value of the assets under actual market conditions.

28 PSE&G Stip., ¶ 4.

29 Id., ¶ 14.

permitted to retain approximately 40% of the net present value of these amounts as a contribution to stranded cost.[30]

(2) *Contribution From Retail Adder Implicit in Shopping Credit Remitted by Non-Shopping Customers.* Just as in the PSE&G proposal, The **Better Choice Settlement Proposal** recognizes that a contribution to stranded costs is made by non-shopping customers who remain with PSE&G for Basic Generation Service ("BGS"). By not shopping, the retail adder in their shopping credit also remains with PSE&G. The retail adder is the amount by which the shopping credit exceeds the wholesale cost of power that PSE&G would incur to serve these customers, and, based on a levelized "retail adder"of 7.3 mils, the non-shoppers will make a $54.64 million contribution to stranded costs.[31] If fewer customers shop, PSE&G would collect even more.

(3) *Non Credited Cost Reductions.* The **Better Choice Settlement Proposal** allows PSE&G to retain over $40 million in expired amortizations and other cost reductions which, all other things being equal, would be passed through to customers in rate reductions.[32]

(4) *Mitigation Opportunities.* Over $800 million, as identified by the Board Staff Consultant's Audit Report, has been identified as the mid-range of future mitigation cost opportunities for PSE&G. The Audit Report found a range of $400 million to $1.1 billion in mitigation cost savings that PSE&G could realize to offset its stranded costs.[33]

In total, under the **Better Choice Settlement Proposal** PSE&G will have an opportunity to collect over $2.8 billion for stranded costs, without even considering the Genco transfer premium, or mitigation saving opportunities.

While the **Better Choice Settlement Proposal** more fully recognizes all sources of stranded cost recovery, it contains a number of significant benefits to PSE&G, including:

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[30] See Attach. "B," Table I.

[31] Attach. B, Table 1. The calculation of the retail adder is explained in Attach. "D," Aff. of John S. Rohrbach.

[32] Id. at 6-7.

[33] Id.

(1) The ability to securitize the same level of stranded costs as PSE&G would be able to securitize under its proposal.[34]

(2) The ability to retain most of the significant cost savings achievable through mitigation by the Board Staff consultants, and as discussed above.

On the whole, the **Better Choice Settlement Proposal's** approach to stranded cost recovery is by far the most balanced and fair.

(f) Basic Generation Service. Similar to the PSE&G proposal, the **Better Choice Settlement Proposal** would enable basic generation service to be competitively bid out in year three, to be effective in the fourth year, and would rebid BGS annually thereafter.[35] The bid would be made on a "prepayment" basis, whereby a bidder would propose a contribution to PSE&G's stranded costs or other costs, either through one or a series of payments. The specific rules for competitive bidding on a stranded or other cost buy-down basis for year 4 and years thereafter would be established by the Board prior to the first bid out.

(g) GENCO Transfer. As indicated, PSE&G obtains substantial value in its settlement without compensation to ratepayers, through transfer of all of its generation plants and related

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[34] As indicated in footnote 16, PSE&G's request to securitize $2.475 billion may not be consistent with the Act.

[35] The **Better Choice Settlement Proposal** would agree to waive, for the purpose of settlement the requirements of Section 9.b (2) of the Energy Competition Act, which would otherwise require the utility to use all net revenues (i.e., profit to the GENCO) derived from the sale of basic generation service to be applied to reduce the MTC, NTC or distribution service rates. This provides a significant benefit to PSE&G.

assets to an unregulated affiliate (GENCO) at a book value indicated in its proposed settlement.[36] This must be recognized as a transfer of enormous value away from PSE&G's ratepayers to PSE&G's shareholders. While many questions can be raised about the legitimacy of such a transfer, in the interest of reaching a fair agreement, the **Better Choice Settlement Proposal** accepts the notion of this asset transfer, with, however a number of significant conditions:

(1) The assignment of a $600 million transfer premium or market value adder to benefit ratepayers;

(2) The establishment of detailed Affiliate Relations rules to be established consistent with the Board's generic determinations in this area;[37]

(3) The initiation of a GENCO Code of Conduct for PSE&G. The general principles of the Code would include a requirement that PSE&G or its affiliated supplier would not receive an unreasonable preference over non-affiliated retail electric suppliers as to GENCO sales of power in other goods or services. In addition, excess power generation would be sold through an accessible bulletin board type system where the GENCO would function as a price taker and would sell all generation resources to the highest bidder(s). The proposed GENCO Code is attached to the Term Sheet (Attachment "A," Appendix 1);

(4) The generating capacity transferred to GENCO would be maintained as a capacity resource within PJM for the first four years; and

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36 PSE&G Stip., Attach. 4.

37 The **Better Choice Settlement Proposal** suggests that the Board promptly issue its generic affiliated interest Code of Conduct and incorporate its terms (assuming they are determined by the parties to be satisfactory to prevent PSE&G from engaging in anti-competitive conduct) as a condition of this Settlement.

(5) Consistent with the Act, the submission of a plan and proposal for the transfer providing details on such crucial items as:

- a specific list of generating and other assets, contracts, intangibles to be transferred;

- the specific accounting entries that will be employed;

- the effect of the transfer on reliability, including whether existing collective bargaining agreements or workforce levels will be affected.[38]

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[38] A detailed list of issues requiring resolution before the transfer can be approved are set out on pages 6-7 of Attach. "C", Aff. of Michael D. Dirmeir.

This type of review appears to be mandated by the Act[39] and is essential if the Board is to fulfill its obligation to assure that the transfer will not affect PSE&G's ability to provide safe, adequate and reasonable service to BGS customers as well as fulfilling its obligation to its employees.

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[39] P.L. 1999 c.23, section 11.c. While section 11.c contemplates the sale of generating assets, and no other section appears to deal with a "transfer", it is clear that this section is intended to guard the public interest by having the Board ensure that a change in control of the assets will not harm the interest of any affected party. The Board is therefore obligated to perform its duty of protecting the public interest by following the requirements established in section 11.c. to evaluate the planned transfer. These requirements include ensuring that the transfer reflects the full market value of all the assets, including intangibles, and ascertaining that the transfer is in the best interest of ratepayers. Further, the Board must ensure that there is continued reliability of the power system, that the buyer (in this case, the transferee) will not have undue market control, and that the impacts on utility employees have been "reasonably mitigated": Act Section 11 c (5). Except for a reference to the protection of utility employee pension rights, pursuant to N.J.S.A. 48:3-7, PSE&G's Stipulation does not discuss any other obligations or protections for its employees.
In a transfer such as this, the legislation mandates that the Board:

> shall include a provision that the related competitive business segment of the public utility, public utility holding company or unaffiliated company shall:
> (1) Recognize the existing employee bargaining unit and shall continue to honor and abide by an existing collective bargaining agreement for the duration of the agreement. The new entity shall be required to bargain in good faith with the existing collective bargaining unit when the existing collective bargaining agreement has expired;
> (2) Shall hire its initial employee complement from among qualified employees of the electric public utility employed at the generating facility at the time of the functional separation or divestiture; and
> (3) Continue such terms and conditions of employment of employees as are in existence at the generating facility at the time of the functional separation or divestiture."

(h) Pro Competitive Shopping Credits. While maintaining the financial viability of the Company and allowing for greater rate cuts, the **Better Choice Settlement Proposal** offers higher customer shopping credits than the PSE&G plan and will permit development of a robust competitive market in the PSE&G service territory. Only as a concession and as a means of reaching amicable agreement, the parties to this Stipulation would be willing to accept the same minimum shopping credit as proposed in the PSE&G Settlement for the year 1999, that is, 4.95¢ kWh (including transmission). Thereafter, however, the shopping credits must be higher; indeed these credits can be much higher consistent with the stranded costs, rate discount, and recovery proposals reflected in the **Better Choice Settlement Proposal**. The minimum shopping credits that need to be adopted are as follows:

Average shopping credit, inclusive of transmission, established for 4 years:

4.95¢ kWh for 1999;

5.40¢ kWh (rounded) for 2000;

5.40¢ kWh for 2001;

5.40¢ kWh for 2002; and

5.40¢ kWh for 2003 (July 31).

Levelized average: 5.356 cents/kWh.

Distribution of the customer shopping credit by tariff rate class is as follows:

RS	6.28¢/kWh
GLP	5.50¢/kWh
LPL-S	5.00¢/kWh
LPL-P	4.80¢/kWh
HTS-SubT:	4.50¢/kWh
HTS-HV:	4.16¢/kWh

In addition, to the above, the Better Choice Proposal recommends that the Board establish a special incentive customer shopping credit for Rates RS and GLP located in Urban Enterprise Zones.

Additional conditions are proposed as follows:

(1) The actual customer shopping credits will be calculated on a rate class basis as the residual after all other unbundled elements are calculated so long as the results do not produce credits that are lower than those shown above.

(2) The customer shopping credit will be allocated between demand and energy (so that customers will be load factor differentiated) for all schedules with separate demand charges.

(3) If during the transition period PSE&G's transmission charges increase for any class above the level included in the above customer shopping credits list, PSE&G will increase the shopping credit accordingly.

In contrast to the **Better Choice Settlement Proposal**, the PSE&G Settlement Proposal's shopping credits are completely inadequate to allow robust competition in PSE&G's market. Attached to this Stipulation are affidavits from a variety of suppliers all of which state that the PSE&G shopping credits are inadequate to foster the development of a robust competitive market for all PSE&G customers and particularly for residential customers.[40]

Indeed, a careful analysis shows that the shopping credits proposed in the PSE&G settlement are significantly below the shopping credits that have been established in the PECO Energy service territory, when the shopping credits are updated for New Jersey- specific costs and increases in the wholesale market. The PECO shopping credits have been described as reflecting a level that is necessary to make robust competition possible for all customer classes. Blindly applying the PECO credits to other jurisdictions without updating them for jurisdictional cost differences and changes in market conditions makes little sense, however. The following chart shows the New Jersey specific costs and updated generic cost increases and their effect on the current PECO-level shopping credits adopted in 1998:

40 Attach. "E," Affidavits of: Ronald J. Matlock, Shell Energy Services, Thomas Boucher, Green Mountain Energy Resources, and James P. McCormick, Strategic Energy Limited.

PECO Shopping Credits Updated for PSE&G in Year 2000:
(***add down from top to reach total***, **e.g.: 4.91+(.0128)+.072+.05+.33+.165 = 5.51):**

		PECO System Average	PECO residential
Start with PECO Shop Credit		4.91	5.66
Add:	*Higher Costs in New Jersey*:		
	- Transmission:	(.0128)	.112
	- Taxes:	.072	.0784
	- LMP* Adjustment:	.05	.05
Add:	*Cost Increases Since PECO Settlement*:		
	- Energy (60% on-peak/40% off):	.33	.36**
	- Installed Capacity:	.165	.201
TOTAL: Parity-Adjusted Shopping Credits:		5.51	6.47

* LMP is an adjustment for a transmission congestion.
** Residential energy costs are higher due to higher on-peak consumption.

As the narrative included as Attachment D describes in detail, long term increases in wholesale forward energy and capacity costs since the PECO case will likely be present at least for the next several years.[41] If these cost escalators are recognized in the PSE&G shopping credits, suppliers anticipate that they will be able to offer an additional 5-7% savings to residential customers.[42] Without recognizing these cost escalations, marketers simply will not be able to provide savings to customers. As the affidavits attached to the Stipulation attest, the PSE&G shopping credits will result in very little, if any, price competition in the PSE&G service territory.[43] The shopping credits proposed in the **Better Choice Settlement Proposal**, therefore, represent the

41 See, Aff. of John S. Rohrbach, Attach. "D," hereto, pgs. 1-3.

42 Id., pgs. 5-6.

43 See, Affidavits included as Attach. "E."

minimum level that can be established to ensure that customers will have realistic opportunities to seek savings through competition, and, in most cases, will be necessary to interest customers in switching to alternative suppliers.

(k) Societal Benefits Charge. The **Better Choice Settlement Proposal** incorporates the PSE&G proposal on this issue.

(l) Non-utility Generation. The **Better Choice Settlement Proposal** incorporates the PSE&G proposal on this issue, with the proviso that PSE&G must seek to obtain maximum value from its NUG contracts by selling all portions of the contract at the market clearing price.

(m) Additional Issues. The **Better Choice Settlement Proposal** lists several additional terms which should be adopted at the same time the PSE&G stranded cost, shopping credit, and unbundling issues are resolved. Resolution of these issues is an important element in the ability of marketers to provide real competitive alternatives to customers, and therefore should not await resolution in generic dockets but should be considered and resolved here. They include the following:

1. Third Party Supplier (ESP) Agreement and Retail Tariff Issues: Third Party Supplier Agreement and Retail Tariff issues must be satisfactorily resolved, including the establishment of the Agreement as a supplier tariff. A PSE&G specific collaborative or other process should be initiated. Specific to PSE&G's terms and conditions, customers should be permitted to change suppliers at will, without incurring large "switching" fees, and not be locked in for a minimum of one year, as set forth in PSE&G's proposed terms and conditions.[44]

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[44] Careful review of supplier and retail tariff issues is essential. The PSE&G proposal offered as a starting point its "Standard Terms and Conditions and Associated Rate Schedules" (PSE&G Stip., Attach. G) which, among other things, propose $20 switching fees and fees to obtain customer load data, all of which could have a significantly negative effect upon the development of competition, if implemented.

2. EDI Issues: An agreement must be reached that creation of necessary EDI protocols and procedure will be established via a collaborative process, and that certification of the suppliers' and PSE&G's EDI systems as being compliant with EDI protocols and Board standards will be done by an independent third party, and not PSE&G.

3. Off Tariff Rate Agreements: PSE&G may continue to serve existing Off-Tariff Rate Agreements consistent with the provisions of the Act.

4. Metering/Billing: The Board will begin proceedings as soon as possible to establish rules for unbundling and competitive provision of metering and billing at the earliest possible date, but no later than January 1, 2000. In the interim, third party suppliers should be permitted to bill for their own services and not be required to rely on PSE&G.

(n) Municipal Aggregation: The Division of the Ratepayer Advocate has actively promoted the adoption of provisions permitting municipal aggregation programs in the Electric Discount and Energy Competition Act because giving municipalities the means to aggregate its constituents is the best way to capture the benefits of competition for the smaller energy consumers. Though the legislators had the foresight to include a government aggregation provision in the Act, one of the weaknesses of the aggregation section is its failure to address how government aggregators can obtain vital customer information that municipalities will find necessary to organize a viable aggregation program. To address this enormous stumbling block to facilitating successful government aggregation programs in the PSE&G service territory, the signatory parties agree that the inclusion of the following provisions is appropriate:

1. Within two weeks of receipt of a customer's request, PSE&G shall provide the usage data (for residential) or load profiles (for commercial and industrial customers) for the past 12 months to the customer making the request without charge to the customers.

2. PSE&G shall provide area based aggregate load profile by municipal boundaries and rate class upon request by a government aggregator. PSE&G shall also provide the government aggregator with a list of addresses (excluding the names) of all energy customers who receive services within the boundaries of the town or municipality without charge; and

3. PSE&G shall maintain and disseminate a Board approved list of licensed third party suppliers approved to supply energy in PSE&G service territory to its customers twice a year without charge. The list will be developed by the Board in a manner that assures that no specific TPS receives a competitive advantage from the dissemination of this list.

__Conclusion__

The undersigned parties agree to be bound by the terms and conditions set forth in the attached Term Sheet and respectfully request that the Board:

(1) Consider the proposed **Better Choice Settlement Proposal** for resolution of the above captioned proceedings;

(2) Develop an evidentiary record on whether the competing plans are in the public interest; and

(3) Approve the **Better Choice Settlement Proposal,** after development of an adequate evidentiary record, and after making the necessary legal and factual findings as consistent with this Petition, as the basis for resolution of the cases;

(4) Take any other action determined to be in the public interest.

Respectfully submitted,

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ATTACHMENT A

ATTACHMENT "A"

PSE&G RESTRUCTURING LITIGATION
JOINT TERM SHEET

<u>Rate Reductions</u>

A customer will be guaranteed the following rate reductions (assuming its power supply costs equals the BGS rate) through July 2003:

a. Aug 1, 1999 - 5% reduction from current rates (inclusive of a 1% prefunding of securitization, if it occurs.)

b. Jan 1, 2000 - 7.0% reduction from current rates (assumes 3% reduction from securitization; any additional reductions over 3% would be passed through to ratepayers).

c. Aug 1, 2001 - 8.25% reduction from current rates.

d. Aug 1, 2002 - final average reduction from current rates (13.9% reduction from present rates for all customer classes).

Any rate increase that would otherwise occur in August 1, 2003 - July 31, 2005 would be mitigated in its entirety by: 1) approximately 60% of the value of the excess of the depreciation distribution amortization grossed up for taxes, 2) 100% of the revenues associated with expired amortization ($35M); 3) a $90 million reduction in the stranded costs related to Salem; and 4) the $90 million overcollection in LEAC. PSE&G rates would remain capped at July 31, 2005 levels unless Public Service files and receives approval for a distribution rate increase.

Additional shopping-related savings, resulting from customers receiving electric generation service from a supplier at a price less than the shopping credit, are above and beyond (i.e. do not count towards) the guaranteed rate reductions.

<u>Rate Design/Cost of Service</u>

Rate reduction in the final phase will be applied to each customer class in a manner to reflect disparate impact of 1998 DSAF increase, to ensure that all customer classes actually realize 10% rate reductions below 4/97 levels.

Apply mandated rate reductions to total bill (except as noted below related to the STC), per PSE&G rate design (2/25 work papers), in order to ensure that all customers among and between rate classes receive same rate reductions.

Transition bond charge and gross-up collected via a per kWh charge, to reflect manner in which revenues associated with bonded plant is currently being collected. Net rate savings reflected by reducing per kilowatt-hour component of each rate class.

Rate Unbundling

Reduce distribution rates by $20 million to reflect current risk-adjusted cost of capital (9.5%) Reduces average distribution rate (including CBT, excluding TEFA) from 2.08 to 2.03 cents.

Securitization

Securitization equaling $2.475 billion in stranded costs (net of issuance) representing 75% of $3.3 billion net of tax stranded costs (assuming Board confirms that the Energy Competition Act allows PSE&G to securitize at this level).

Total bonds issued: approximately $2.5375 billion, representing $2.475 billion plus one-half of verified, actual issuance costs, with maximum allowable amount not to exceed $62.5 million. Term of bonds 15 years.

Transition bond charge set to collect principal and interest on bonds only. Gross up amount associated with converting net-of-tax securitized stranded costs to pre-tax are collected through a tax MTC over 15 years, to recover actual state and federal taxes, subject to a true-up.

Stranded Costs

Total owned generation stranded costs (net of tax) established at approximately $3.30 billion.

In addition to securitized amount, the Company will be given an opportunity to recover an estimated $268.1 million on a NPV, net-of -tax basis over the 4-year transition period. This amount will be recovered through the following:[1]

1) Retail adder on retained customers (calculated at $54.6 million);

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[1] A $90 million reduction in allowed stranded cost recovery related to Salem has been reflected as a source of funding for additional rate decreases (See, "Rate Reductions", above).

2) 40% of the depreciation savings ($568.7 million nominal, $478 million, NPV,) from excess distribution depreciation reserve amortization: $170.5 million;[2] and

3) Remaining unrefunded rate reductions ($43 million).

The remainder of allowed stranded cost recovery will be assumed to be recovered from recognition of the transfer premium above book value of the PSE&G's generation units to a Genco subsidiary ($600 million) and mitigation opportunities.

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[2] The remainder of the excess depreciation distribution amortization will be used to offset the rate increases that otherwise may occur in years 5 and 6.

Transition Period

4 years

Basic Generation Service

PSE&G to provide for first three years. BGS contract supplier is GENCO at pre-established prices (shopping credit less retail adder).[3]

BGS will be competitively bid out in year 3 for fourth year and annually thereafter. The bid will reflect a payment or series of payments based upon pre-established shopping credit for year 4. If the bid for generation results in a payment to PSE&G, it shall be considered as a part of the MTC. If the bid for generation requires a payment by PSE&G, such payment shall be subject to deferral and subsequent recovery with interest. Specific rules for the BGS bid out, including the rules for year 5 and thereafter, will be established by the Board prior to the first bid out, in a collaborative process in which all interested persons will be given the opportunity to participate.

PSE&G will not promote its BGS service as a competitive alternative.

GENCO Transfer

PSE&G will be permitted to transfer generation assets to a separate GENCO, subject to the following:

1) $600 million credit to ratepayers to recognize a transfer premium, i.e., a market value adder;

2) Detailed Affiliate Relations rules to be decided generically via BPU standards conditioned upon BPU issuance of proposed rules within 15 days of agreement in principle, final rules promulgated after opportunity to comment, and agreement contingent upon Rules which ensure fair dealing and prevents unfair advantage by PSE&G affiliates;

3) GENCO Code of Conduct adopted for application to PSE&G (attached as Appendix 1). General Principles of the Code would include the following:

> "To recognize PSE&G's market power resulting from its historic position as the monopoly provider of electric service in its service territory, GENCO shall not offer power or other services to any of

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[3] PSE&G will not be required to reduce rates to recognize the profit (net revenues) from the sale of BGS service, as per Section 9.b(2) of the Energy Competition Act.

its affiliates which are not made generally available to non-affiliated companies, nor shall it offer such power or other services to affiliates at prices more favorable than those generally available in the competitive marketplace and/or to those offered to non-affiliated companies. This provision shall not apply to the BGS Wholesale Supply Agreement entered into between GENCO and Public Service and approved by the Board;"

(4) Generating capacity transferred to GENCO maintained as a capacity resource within PJM for the first *4* years; and

(5) Submission of detailed plan for and accounting of proposed transfer of assets subject to final approval by the Board.

Shopping Credits

Average shopping credit, inclusive of transmission, established (5.356 cents levelized) over 4 years.

4.95 cents for 1999;
5.40 (rounded) for 2000;
5.40 for 2001;
5.40 for 2002; and
5.40 for 2003(July 31).

Distribution as follows (after year 1999)

RS	6.28
GLP	5.50
LPL-S	5.00
LPL-P	4.80
HTS-SubT:	4.50
HTS-HV:	4.16

In addition to the above, a special incentive shopping credit will be established for customers served on rates RS and GLP located in Urban Enterprise Zones.

Additional Conditions:

1) The actual shopping credits will be calculated on a rate class by rate class basis with the shopping credit as the residual, after all other elements are calculated, assuming that the results produce credits that are no lower than the above to allow competition to develop.

2) The shopping credit will be allocated between demand and energy (so those customers will be load factor differentiated) for all schedules with separate demand charges.

3) If PSE&G transmission charges for each class assumed in the above shopping credits go up, PSE&G will increase shopping credit.

Societal Benefits Charge

Clause with deferrals during four year rate cap period. Reset annually thereafter.

Interest on over/under recoveries at mid-term cost of debt.

Explicit agreement that the DSM generation-related lost revenue collection (and deferral) ends as of Aug 1, 1999.

Non-Utility Generation

Clause with deferrals during four year rate cap period. Reset annually thereafter.

Clause to credit market value of NUG capacity and energy payments and any other products that are sold. PSE&G required to maximize market value realized.

Interest on over/under recoveries at mid-term cost of debt.

Additional Issues

(a) Third Party Supplier (ESP) Agreement and Retail Tariff Issues: Third Party Supplier Agreement and Retail Tariff issues must be satisfactorily resolved, including the establishment of the Agreement as a supplier tariff. A PSE&G specific collaborative or other process should be initiated. Specific to PSE&G's terms and conditions, customers should be permitted to change suppliers at will, without switching fees and not be locked in for a minimum of one year.

(b) EDI Issues: Agreement that creation of necessary EDI protocols and procedure will be established via a collaborative proceeding and that agreement that any certification of a supplier's EDI systems as compliant with BPU-approved uniform standards shall be done by independent third party and not PSE&G.

(c) Off-Tariff Rate Agreements ("OTRAs"): Public Service may continue to serve existing Off-Tariff Rate Agreements consistent with the terms of the Act.

(d) Metering/Billing: Board will as soon as possible begin proceeding to establish rules for unbundling and competitive supply of PSE&G metering and billing at earliest possible date but no later than January 1, 2000. In the interim, third party suppliers are permitted to separately bill for generation supply service.

(e) Choice of Suppliers: Customers shall be permitted to change suppliers at will, without incurring large switching fees and without being locked in for one year.

(f) Municipal Aggregation: The Division of the Ratepayer Advocate has actively promoted the adoption of provisions permitting municipal aggregation programs in the Electric Discount and Energy Competition Act because giving municipalities the means to aggregate its constituents is the best way to capture the benefits of competition for the smaller energy consumers. Though the legislators had the foresight to include a government aggregation provision in the Act, one of the weaknesses of the aggregation section is its failure to address how government aggregators can obtain vital customer information that municipalities will find necessary to organize a viable aggregation program. To address this enormous stumbling block to facilitating successful government aggregation programs in the PSE&G service territory, we believe the inclusion of the following provisions is appropriate:

1. Within two weeks of receipt of a customer's request, PSE&G shall provide the usage data (for residential) or load profiles (for commercial and industrial customers) for the past 12 months to the customer making the request at no cost to consumers.

2. PSE&G shall provide area based aggregate load profiles by municipal boundaries and rate class upon request by a government aggregator. PSE&G shall also provide the government aggregator with a list of addresses (excluding the names) of all energy customers who receive services within the boundaries of the town or municipality at no cost to customers;

3. PSE&G shall maintain and disseminate a list of licensed third party suppliers that are Board approved to supply energy in PSE&G service territory to its customers twice a year at no cost to consumers. The list will be developed by the Board in a manner that assures that no specific TPS receives a competitive advantage from the dissemination of this list.

Effect of Term Sheet:

The parties entering into the Stipulation of Settlement agree to be bound by its terms. The Term Sheet represents an attempt to achieve a mutually balanced resolution of the issues in these proceedings which the parties intend to be accepted and approved in its entirety.

In the event any particular aspect of the Term Sheet is not accepted and approved by the Board, the Term Sheet and the parties agreement thereto shall be voidable by any signatory party, and the parties shall be placed in the same position that they were in immediately prior to the agreement to the Term Sheet.

The Parties agree that their agreement to this Term Sheet is without admission against or prejudice to any factual or legal position which any of the signatories may assert in other proceedings, or in these proceedings or on appeal if the Stipulation of Settlement is not accepted in its entirety by the Board.

APPENDIX 1

GENCO Code of Conduct

To recognize PSE&G's market power, both in New Jersey and in its service territory, and that it will continue to have such market power after a transfer of assets to a GENCO, and in addition to any other PSE&G Affiliate Standard of Conduct that might apply, the following shall apply to transactions by: 1) PSE&G in its electric distribution company provider of last resort /Basic Generation Service ("BGS") role ("PSE&G-LDC"); 2) an Electric Power Supplier ("EPS"), which is an affiliate or division of PSE&G or PSEG; 3) any other affiliate or division of PSE&G or PSE (PSE&G-Supplier"); and 4) any PSE&G or PSEG generation division or affiliated generation company ("GENCO") to which assets have been transferred, leased or assigned pursuant to this Settlement.

1 . Neither PSE&G-LDC, PSE&G-Supplier, nor PSE&G-EPS shall receive from GENCO an unreasonable preference over a non-affiliated EPS or treatment that is not comparable to that afforded a non-affiliated EPS in the purchase, sale, use or conveyance of goods and services, including energy, installed capacity, generation related ancillary services, transmission rights, capacity benefit margins or any other generation and transmission product, service or asset. This provision shall not apply to the BGS Wholesale Supply Agreement entered into between GENCO and PSE&G-LDC and approved by the Board for the initial three year period after August, 1999.

2. PSE&G-LDC, PSE&G EPS and PSE&G-Supplier shall receive tariffed generation or transmission from the GENCO, to the extent GENCO provides tariffed services, in a manner that is comparable or otherwise is not anti-competitive when compared to how the same tariff services are provided to non-affiliated EPSs.

3. No transaction between a PSE&G-LDC, or PSE&G-Supplier and GENCO shall involve an anti-competitive cross subsidy and all such transactions shall comply with applicable law.

4. PSE&G-GENCO will function as an electric wholesale generator and not make retail sales.

5. Excess wholesale generation beyond generation necessary to serve the BGS shall be offered on terms and conditions comparable to those provided to PSE&G- EGS or PSE&G-Supplier. PSE&G, in consultation with other interested Joint Petitioners, shall develop and file with the Board on, or before July 1, 1999, a protocol for the public and electronic posting prior to sale of excess wholesale generation sold by the GENCO.

6. GENCO shall not engage in anti-competitive or discriminatory conduct which prevents retail electricity customers in this State from obtaining the benefits of a properly functioning and workable competitive retail electricity market.

7. The GENCO will maintain its installed capacity and firm energy as capacity resource until July 31, 2003.

8. PSE&G-LDC, GENCO, and PSE&G-EPS and Supplier will file monthly with the Board complete information about price, terms, and conditions concerning transactions involving GENCO that are covered by these provisions. The Board's standard rules governing proprietary information shall apply.

9. PSE&G-EDC shall establish and file with the Board a dispute resolution procedure to address complaints alleging violation of the provisions. The Board shall finally adjudicate within 60 days any complaint filed with the BPU concerning these provisions.

10. This agreement does not confer jurisdiction on the Board that does not otherwise exist under applicable law, and any Order issued finding a violation of these provisions shall be directed to PSE&G-LDC, PSE&G-EPS or Supplier. Violations of this Code of Conduct shall constitute a violation of any applicable PSE&G Code of Conduct or Competitive Safeguard rules. With the exception of paragraphs 4, 5 and 7, imposition of these provisions does not constitute state action for antitrust purposes.

11. With the exception of paragraphs 4, 5 and 7, these provisions will remain in effect until the expiration of the STC collection period or until appropriate and applicable competitive safeguards or Code of Conduct are adopted by the Federal Energy Regulatory Commission ("FERC"), whichever occurs first. All signatories may fully participate in FERC proceedings concerning competitive safeguards or Code of Conduct for GENCO.

ATTACHMENT B

Table 1: BETTER CHOICE PROPOSAL for PSE&G

Total Stranded Costs:		$	3,300,000,000
Recovery Opportunity Comprised of:			
Item 1:	Securitized (Including Allowed Issuance Costs) *	$	2,637,500,000
Item 2:	Retail Adder Retained on non-shoppers	$	54,635,943
Item 3:	Genco Above Book Transfer Amount	$	600,000,000
Item 4:	Distribution Depreciation Adjustment	$	170,364,057
Item 5:	Non-credited Rate Reductions	$	42,985,606
Item 6:	Mitigation Opportunities (see Board Staff Audit Report, page 128):	$	828,000,000
	TOTAL AVAILABLE RESOURCES:	$	4,233,485,606

Model Assumptions:

Mandatory Statutory Reductions (vs. 10.447 bundled rate):	
First 12 months	5.00%
Months 13-24:	7.00%
Months 25 - 36:	8.25%
Months 37 - 48:	13.90%
Months 49 -72: (approximate)	*13.90%*

Assumed kWh Shopping	
1999	*5.00%*
2000	*30.00%*
2001	*40.00%*
2002	*40.00%*
2003	*50.00%*

System Shopping Credits:	
1999	*4.950*
2000	*5.400*
2001	*5.400*
2002	*5.400*
2003	*5.400*

Sustained rate reductions for months 49 to 72 funded as follows:		
Expired Electric Amortizations	$	35,000,000
Salem stranded cost reduction	$	90,000,000
LEAC Excess (After-tax NPV)	$	90,000,000
Balance In Distribution Depreciation Adjustment	$	290,138,577
Total	$	505,138,577
Total with Tax Gross Up	$	914,300,824
Remaining for PSE&G after funding reductions	$	42,985,606

* Securitization Detail:		
Securitization Interest Rate		6.60%
Monthly Recovery	$	22,104,349
Transition Period		15.0
Securitization Limit as claimed by PSE&G		75%
Securitized (w/ith 50% Issuance)	$	2,537,500,000
PSE&G Issuance Cost Contrib. (50% Claim)	$	62,500,000

Other:		
Discount Rate	8.42%	
SUT Rate	6.00%	
TEFA Rate	3.46%	
	44.00%	*Tax Rate (S&L)*

NTC Buildup		
NPV Amount	$	1,600,000,000
Discount Rate		8.00%
Years	$	15
Annual Recovery	$	15,290,433

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Item 5:	Non-credited Rate Reductions	$	42,985,606
Item 6:	Mitigation Opportunities (see Board Staff Audit Report, page 128):	$	828,000,000
	TOTAL AVAILABLE RESOURCES:	$	4,233,485,606

Model Assumptions:

Mandatory Statutory Reductions (vs. 10.447 bundled rate):	
First 12 months	5.00%
Months 13-24:	7.00%
Months 25 - 36:	8.25%
Months 37 - 48:	13.90%
Months 49 -72: (approximate)	*13.90%*

Assumed kWh Shopping	
1999	*5.00%*
2000	*30.00%*
2001	*40.00%*
2002	*40.00%*
2003	*50.00%*

System Shopping Credits:	
1999	*4.950*
2000	*5.400*
2001	*5.400*
2002	*5.400*
2003	*5.400*

Sustained rate reductions for months 49 to 72 funded as follows:		
Expired Electric Amortizations	$	35,000,000
Salem stranded cost reduction	$	90,000,000
LEAC Excess (After-tax NPV)	$	90,000,000
Balance in Distribution Depreciation Adjustment	$	290,138,577
Total	$	505,138,577
Total with Tax Gross Up	$	914,300,824
Remaining for PSE&G after funding reductions	$	42,985,606

* Securitization Detail:		
Securitization Interest Rate		6.50%
Monthly Recovery	$	22,104,349
Transition Period		15.0
Securitization Limit as claimed by PSE&G		75%
Securitized (w/ith 50% issuance)	$	2,537,500,000
PSE&G Issuance Cost Contrib. (50% Claim)	$	62,500,000

Other:	
Discount Rate	8.42%
SUT Rate	6.00%
TEFA Rate	3.46%
Tax Rate (S&L)	44.00%

NTC Buildup		
NPV Amount	$	1,600,000,000
Discount Rate		8.00%
Years	$	15
Annual Recovery	$	15,290,433

Table 2: Unbundled Elements		Bundled Rate	Rate Cut (%)	Bundled Rate Cap	Distrib & CBT & TEFA	SBC	NTC	STC (w/ Taxes)	Shopping Credit	Total Non-MTC	Sustained Rate Reduct.
MONTH	YEAR										
August	1999	$ 0.10447	5.00%	$ 0.0993	$ 0.0266	$ 0.0066	$ 0.0047		$ 0.04950	$ 0.08743	
September	1999	$ 0.10447	5.00%	$ 0.0993	$ 0.0266	$ 0.0066	$ 0.0047	$ -	$ 0.04950	$ 0.08742	
October	1999	$ 0.10447	5.00%	$ 0.0993	$ 0.0266	$ 0.0066	$ 0.0047	$ -	$ 0.04950	$ 0.08742	
November	1999	$ 0.10447	5.00%	$ 0.0993	$ 0.0266	$ 0.0066	$ 0.0047	$ -	$ 0.04950	$ 0.08741	
December	1999	$ 0.10447	5.00%	$ 0.0993	$ 0.0266	$ 0.0066	$ 0.0047	$ -	$ 0.04950	$ 0.08741	
January	2000	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0047	$ 0.01014	$ 0.05400	$ 0.10197	
February	2000	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0047	$ 0.0101	$ 0.05400	$ 0.10196	
March	2000	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0047	$ 0.0101	$ 0.05400	$ 0.10194	
April	2000	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0047	$ 0.0101	$ 0.05400	$ 0.10193	
May	2000	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0047	$ 0.0101	$ 0.05400	$ 0.10192	
June	2000	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0047	$ 0.0101	$ 0.05400	$ 0.10190	
July	2000	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0046	$ 0.0101	$ 0.05400	$ 0.10189	
August	2000	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0046	$ 0.0101	$ 0.05400	$ 0.10188	
September	2000	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0046	$ 0.0101	$ 0.05400	$ 0.10186	
October	2000	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0046	$ 0.0101	$ 0.05400	$ 0.10185	
November	2000	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0046	$ 0.0100	$ 0.05400	$ 0.10183	
December	2000	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0046	$ 0.0100	$ 0.05400	$ 0.10182	
January	2001	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0046	$ 0.0100	$ 0.05400	$ 0.10181	
February	2001	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0046	$ 0.0100	$ 0.05400	$ 0.10179	
March	2001	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0046	$ 0.0100	$ 0.05400	$ 0.10178	
April	2001	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0046	$ 0.0100	$ 0.05400	$ 0.10177	
May	2001	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0046	$ 0.0100	$ 0.05400	$ 0.10175	
June	2001	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0046	$ 0.0100	$ 0.05400	$ 0.10174	
July	2001	$ 0.10447	7.00%	$ 0.0972	$ 0.0266	$ 0.0066	$ 0.0046	$ 0.0100	$ 0.05400	$ 0.10173	
August	2001	$ 0.10447	8.25%	$ 0.0959	$ 0.0265	$ 0.0066	$ 0.0046	$ 0.0100	$ 0.05400	$ 0.10167	
September	2001	$ 0.10447	8.25%	$ 0.0959	$ 0.0265	$ 0.0066	$ 0.0046	$ 0.0100	$ 0.05400	$ 0.10166	
October	2001	$ 0.10447	8.25%	$ 0.0959	$ 0.0265	$ 0.0066	$ 0.0046	$ 0.0099	$ 0.05400	$ 0.10165	
November	2001	$ 0.10447	8.25%	$ 0.0959	$ 0.0265	$ 0.0066	$ 0.0046	$ 0.0099	$ 0.05400	$ 0.10163	
December	2001	$ 0.10447	8.25%	$ 0.0959	$ 0.0265	$ 0.0066	$ 0.0046	$ 0.0099	$ 0.05400	$ 0.10162	
January	2002	$ 0.10447	8.25%	$ 0.0959	$ 0.0265	$ 0.0066	$ 0.0046	$ 0.0099	$ 0.05400	$ 0.10161	
February	2002	$ 0.10447	8.25%	$ 0.0959	$ 0.0265	$ 0.0066	$ 0.0046	$ 0.0099	$ 0.05400	$ 0.10159	
March	2002	$ 0.10447	8.25%	$ 0.0959	$ 0.0265	$ 0.0066	$ 0.0046	$ 0.0099	$ 0.05400	$ 0.10158	
April	2002	$ 0.10447	8.25%	$ 0.0959	$ 0.0265	$ 0.0066	$ 0.0046	$ 0.0099	$ 0.05400	$ 0.10157	
May	2002	$ 0.10447	8.25%	$ 0.0959	$ 0.0265	$ 0.0066	$ 0.0046	$ 0.0099	$ 0.05400	$ 0.10155	
June	2002	$ 0.10447	8.25%	$ 0.0959	$ 0.0265	$ 0.0066	$ 0.0046	$ 0.0099	$ 0.05400	$ 0.10154	
July	2002	$ 0.10447	8.25%	$ 0.0959	$ 0.0265	$ 0.0066	$ 0.0045	$ 0.0099	$ 0.05400	$ 0.10153	
August	2002	$ 0.10447	13.90%	$ 0.0900	$ 0.0263	$ 0.0066	$ 0.0045	$ 0.0099	$ 0.05400	$ 0.10131	
September	2002	$ 0.10447	13.90%	$ 0.0900	$ 0.0263	$ 0.0066	$ 0.0045	$ 0.0098	$ 0.05400	$ 0.10129	
October	2002	$ 0.10447	13.90%	$ 0.0900	$ 0.0263	$ 0.0066	$ 0.0045	$ 0.0098	$ 0.05400	$ 0.10128	
November	2002	$ 0.10447	13.90%	$ 0.0900	$ 0.0263	$ 0.0066	$ 0.0045	$ 0.0098	$ 0.05400	$ 0.10127	
December	2002	$ 0.10447	13.90%	$ 0.0900	$ 0.0263	$ 0.0066	$ 0.0045	$ 0.0098	$ 0.05400	$ 0.10125	
January	2003	$ 0.10447	13.90%	$ 0.0900	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0098	$ 0.05400	$ 0.09813	
February	2003	$ 0.10447	13.90%	$ 0.0900	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0098	$ 0.05400	$ 0.09812	
March	2003	$ 0.10447	13.90%	$ 0.0900	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0098	$ 0.05400	$ 0.09810	
April	2003	$ 0.10447	13.90%	$ 0.0900	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0098	$ 0.05400	$ 0.09809	
May	2003	$ 0.10447	13.90%	$ 0.0900	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0098	$ 0.05400	$ 0.09808	
June	2003	$ 0.10447	13.90%	$ 0.0900	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0098	$ 0.05400	$ 0.09806	
July	2003	$ 0.10447	13.90%	$ 0.0900	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0098	$ 0.05400	$ 0.09805	
August	2003	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0097		$ 0.09804	$ 0.01120
September	2003	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0097		$ 0.09802	$ 0.01119
October	2003	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0097		$ 0.09801	$ 0.01118
November	2003	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0097		$ 0.09800	$ 0.01117
December	2003	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0097		$ 0.09799	$ 0.01115
January	2004	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0097		$ 0.09797	$ 0.01114
February	2004	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0097		$ 0.09796	$ 0.01113
March	2004	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0097		$ 0.09795	$ 0.01112
April	2004	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0097		$ 0.09793	$ 0.01111

May	2004	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0097	$ 0.09792	$ 0.01110
June	2004	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0045	$ 0.0097	$ 0.09791	$ 0.01109
July	2004	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0096	$ 0.09790	$ 0.01108
August	2004	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0096	$ 0.09788	$ 0.01107
September	2004	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0096	$ 0.09787	$ 0.01106
October	2004	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0096	$ 0.09786	$ 0.01105
November	2004	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0096	$ 0.09784	$ 0.01104
December	2004	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0096	$ 0.09783	$ 0.01103
January	2005	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0096	$ 0.09782	$ 0.01102
February	2005	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0096	$ 0.09780	$ 0.01101
March	2005	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0096	$ 0.09779	$ 0.01100
April	2005	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0096	$ 0.09778	$ 0.01099
May	2005	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0096	$ 0.09777	$ 0.01098
June	2005	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0095	$ 0.09775	$ 0.01097
July	2005	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0095	$ 0.09774	$ 0.01096
August	2005	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0095	$ 0.09773	
September	2005	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0095	$ 0.09772	
October	2005	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0095	$ 0.09770	
November	2005	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0095	$ 0.09769	
December	2005	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0095	$ 0.09768	
January	2006	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0095	$ 0.09766	
February	2006	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0095	$ 0.09765	
March	2006	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0095	$ 0.09764	
April	2006	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0095	$ 0.09763	
May	2006	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0095	$ 0.09761	
June	2006	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0094	$ 0.09760	
July	2006	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0044	$ 0.0094	$ 0.09759	
August	2006	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0094	$ 0.09758	
September	2006	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0094	$ 0.09756	
October	2006	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0094	$ 0.09755	
November	2006	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0094	$ 0.09754	
December	2006	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0094	$ 0.09753	
January	2007	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0094	$ 0.09751	
February	2007	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0094	$ 0.09750	
March	2007	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0094	$ 0.09749	
April	2007	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0094	$ 0.09748	
May	2007	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0094	$ 0.09746	
June	2007	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0093	$ 0.09745	
July	2007	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0093	$ 0.09744	
August	2007	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0093	$ 0.09743	
September	2007	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0093	$ 0.09741	
October	2007	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0093	$ 0.09740	
November	2007	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0093	$ 0.09739	
December	2007	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0093	$ 0.09738	
January	2008	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0093	$ 0.09736	
February	2008	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0093	$ 0.09735	
March	2008	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0093	$ 0.09734	
April	2008	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0093	$ 0.09733	
May	2008	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0092	$ 0.09731	
June	2008	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0092	$ 0.09730	
July	2008	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0092	$ 0.09729	
August	2008	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0043	$ 0.0092	$ 0.09728	
September	2008	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0092	$ 0.09726	
October	2008	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0092	$ 0.09725	
November	2008	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0092	$ 0.09724	
December	2008	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0092	$ 0.09723	
January	2009	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0092	$ 0.09721	
February	2009	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0092	$ 0.09720	
March	2009	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0092	$ 0.09719	
April	2009	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0092	$ 0.09718	
May	2009	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0091	$ 0.09717	

June	2009	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0091	$ 0.09715
July	2009	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0091	$ 0.09714
August	2009	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0091	$ 0.09713
September	2009	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0091	$ 0.09712
October	2009	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0091	$ 0.09710
November	2009	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0091	$ 0.09709
December	2009	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0091	$ 0.09708
January	2010	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0091	$ 0.09707
February	2010	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0091	$ 0.09706
March	2010	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0091	$ 0.09704
April	2010	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0091	$ 0.09703
May	2010	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0090	$ 0.09702
June	2010	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0090	$ 0.09701
July	2010	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0090	$ 0.09700
August	2010	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0090	$ 0.09698
September	2010	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0090	$ 0.09697
October	2010	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0042	$ 0.0090	$ 0.09696
November	2010	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0090	$ 0.09695
December	2010	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0090	$ 0.09693
January	2011	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0090	$ 0.09692
February	2011	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0090	$ 0.09691
March	2011	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0090	$ 0.09690
April	2011	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0090	$ 0.09689
May	2011	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0089	$ 0.09687
June	2011	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0089	$ 0.09686
July	2011	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0089	$ 0.09685
August	2011	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0089	$ 0.09684
September	2011	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0089	$ 0.09683
October	2011	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0089	$ 0.09682
November	2011	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0089	$ 0.09680
December	2011	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0089	$ 0.09679
January	2012	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0089	$ 0.09678
February	2012	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0089	$ 0.09677
March	2012	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0089	$ 0.09676
April	2012	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0089	$ 0.09674
May	2012	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0089	$ 0.09673
June	2012	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0088	$ 0.09672
July	2012	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0088	$ 0.09671
August	2012	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0088	$ 0.09670
September	2012	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0088	$ 0.09668
October	2012	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0088	$ 0.09667
November	2012	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0088	$ 0.09666
December	2012	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0088	$ 0.09665
January	2013	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0041	$ 0.0088	$ 0.09664
February	2013	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0088	$ 0.09663
March	2013	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0088	$ 0.09661
April	2013	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0088	$ 0.09660
May	2013	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0088	$ 0.09659
June	2013	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0087	$ 0.09658
July	2013	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0087	$ 0.09657
August	2013	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0087	$ 0.09656
September	2013	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0087	$ 0.09654
October	2013	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0087	$ 0.09653
November	2013	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0087	$ 0.09652
December	2013	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0087	$ 0.09651
January	2014	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0087	$ 0.09650
February	2014	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0087	$ 0.09649
March	2014	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0087	$ 0.09647
April	2014	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0087	$ 0.09646
May	2014	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0087	$ 0.09645
June	2014	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0087	$ 0.09644

July	2014	$ 0.10447	14.06%	$ 0.0898	$ 0.0232	$ 0.0066	$ 0.0040	$ 0.0086		$ 0.09643
August	2014	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ -	$ 0.0086		$ 0.09243
September	2014	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ -	$ 0.0086		$ 0.09243
October	2014	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ -	$ 0.0086		$ 0.09242
November	2014	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ -	$ 0.0086		$ 0.09241
December	2014	$ 0.10447	14.05%	$ 0.0898	$ 0.0232	$ 0.0066	$ -	$ 0.0086		$ 0.09240

Table 4: Securitization Stream

Note: SUT and Other taxes are built into the STC on Attachment 2		Securitization w/ 50% Issuance:		$ 2,600,000,000	Term:	15 years
		Securitization Interest Rate:		6.50%		

MONTH	YEAR	Begin	Pmt.	Int.	Prin.	End
January	2000	$ 2,537,500,000	$ 22,104,349	$ 13,744,792	$ 8,359,557	$ 2,529,140,443
February	2000	$ 2,529,140,443	$ 22,104,349	$ 13,699,511	$ 8,404,838	$ 2,520,735,605
March	2000	$ 2,520,735,605	$ 22,104,349	$ 13,653,985	$ 8,450,364	$ 2,512,285,241
April	2000	$ 2,512,285,241	$ 22,104,349	$ 13,608,212	$ 8,496,137	$ 2,503,789,104
May	2000	$ 2,503,789,104	$ 22,104,349	$ 13,562,191	$ 8,542,158	$ 2,495,246,946
June	2000	$ 2,495,246,946	$ 22,104,349	$ 13,515,921	$ 8,588,428	$ 2,486,658,518
July	2000	$ 2,486,658,518	$ 22,104,349	$ 13,469,400	$ 8,634,949	$ 2,478,023,569
August	2000	$ 2,478,023,569	$ 22,104,349	$ 13,422,628	$ 8,681,721	$ 2,469,341,848
September	2000	$ 2,469,341,848	$ 22,104,349	$ 13,375,602	$ 8,728,747	$ 2,460,613,101
October	2000	$ 2,460,613,101	$ 22,104,349	$ 13,328,321	$ 8,776,028	$ 2,451,837,073
November	2000	$ 2,451,837,073	$ 22,104,349	$ 13,280,784	$ 8,823,565	$ 2,443,013,508
December	2000	$ 2,443,013,508	$ 22,104,349	$ 13,232,990	$ 8,871,359	$ 2,434,142,149
January	2001	$ 2,434,142,149	$ 22,104,349	$ 13,184,937	$ 8,919,412	$ 2,425,222,737
February	2001	$ 2,425,222,737	$ 22,104,349	$ 13,136,623	$ 8,967,726	$ 2,416,255,011
March	2001	$ 2,416,255,011	$ 22,104,349	$ 13,088,048	$ 9,016,301	$ 2,407,238,710
April	2001	$ 2,407,238,710	$ 22,104,349	$ 13,039,210	$ 9,065,139	$ 2,398,173,571
May	2001	$ 2,398,173,571	$ 22,104,349	$ 12,990,107	$ 9,114,242	$ 2,389,059,329
June	2001	$ 2,389,059,329	$ 22,104,349	$ 12,940,738	$ 9,163,611	$ 2,379,895,718
July	2001	$ 2,379,895,718	$ 22,104,349	$ 12,891,102	$ 9,213,247	$ 2,370,682,471
August	2001	$ 2,370,682,471	$ 22,104,349	$ 12,841,197	$ 9,263,152	$ 2,361,419,319
September	2001	$ 2,361,419,319	$ 22,104,349	$ 12,791,021	$ 9,313,328	$ 2,352,105,991
October	2001	$ 2,352,105,991	$ 22,104,349	$ 12,740,574	$ 9,363,775	$ 2,342,742,216
November	2001	$ 2,342,742,216	$ 22,104,349	$ 12,689,854	$ 9,414,495	$ 2,333,327,721
December	2001	$ 2,333,327,721	$ 22,104,349	$ 12,638,858	$ 9,465,491	$ 2,323,862,230
January	2002	$ 2,323,862,230	$ 22,104,349	$ 12,587,587	$ 9,516,762	$ 2,314,345,468
February	2002	$ 2,314,345,468	$ 22,104,349	$ 12,536,038	$ 9,568,311	$ 2,304,777,157
March	2002	$ 2,304,777,157	$ 22,104,349	$ 12,484,210	$ 9,620,139	$ 2,295,157,018
April	2002	$ 2,295,157,018	$ 22,104,349	$ 12,432,101	$ 9,672,248	$ 2,285,484,770
May	2002	$ 2,285,484,770	$ 22,104,349	$ 12,379,709	$ 9,724,640	$ 2,275,760,130
June	2002	$ 2,275,760,130	$ 22,104,349	$ 12,327,034	$ 9,777,315	$ 2,265,982,815
July	2002	$ 2,265,982,815	$ 22,104,349	$ 12,274,074	$ 9,830,275	$ 2,256,152,540
August	2002	$ 2,256,152,540	$ 22,104,349	$ 12,220,826	$ 9,883,523	$ 2,246,269,017
September	2002	$ 2,246,269,017	$ 22,104,349	$ 12,167,291	$ 9,937,058	$ 2,236,331,959
October	2002	$ 2,236,331,959	$ 22,104,349	$ 12,113,465	$ 9,990,884	$ 2,226,341,075
November	2002	$ 2,226,341,075	$ 22,104,349	$ 12,059,347	$ 10,045,002	$ 2,216,296,073
December	2002	$ 2,216,296,073	$ 22,104,349	$ 12,004,937	$ 10,099,412	$ 2,206,196,661
January	2003	$ 2,206,196,661	$ 22,104,349	$ 11,950,232	$ 10,154,117	$ 2,196,042,544
February	2003	$ 2,196,042,544	$ 22,104,349	$ 11,895,230	$ 10,209,119	$ 2,185,833,425
March	2003	$ 2,185,833,425	$ 22,104,349	$ 11,839,931	$ 10,264,418	$ 2,175,569,007
April	2003	$ 2,175,569,007	$ 22,104,349	$ 11,784,332	$ 10,320,017	$ 2,165,248,990
May	2003	$ 2,165,248,990	$ 22,104,349	$ 11,728,432	$ 10,375,917	$ 2,154,873,073
June	2003	$ 2,154,873,073	$ 22,104,349	$ 11,672,229	$ 10,432,120	$ 2,144,440,953
July	2003	$ 2,144,440,953	$ 22,104,349	$ 11,615,722	$ 10,488,627	$ 2,133,952,326
August	2003	$ 2,133,952,326	$ 22,104,349	$ 11,558,908	$ 10,545,441	$ 2,123,406,885
September	2003	$ 2,123,406,885	$ 22,104,349	$ 11,501,787	$ 10,602,562	$ 2,112,804,323
October	2003	$ 2,112,804,323	$ 22,104,349	$ 11,444,357	$ 10,659,992	$ 2,102,144,331
November	2003	$ 2,102,144,331	$ 22,104,349	$ 11,386,615	$ 10,717,734	$ 2,091,426,597
December	2003	$ 2,091,426,597	$ 22,104,349	$ 11,328,561	$ 10,775,788	$ 2,080,650,809
January	2004	$ 2,080,650,809	$ 22,104,349	$ 11,270,192	$ 10,834,157	$ 2,069,816,652
February	2004	$ 2,069,816,652	$ 22,104,349	$ 11,211,507	$ 10,892,842	$ 2,058,923,810
March	2004	$ 2,058,923,810	$ 22,104,349	$ 11,152,504	$ 10,951,845	$ 2,047,971,965
April	2004	$ 2,047,971,965	$ 22,104,349	$ 11,093,181	$ 11,011,168	$ 2,036,960,797
May	2004	$ 2,036,960,797	$ 22,104,349	$ 11,033,538	$ 11,070,811	$ 2,025,889,986
June	2004	$ 2,025,889,986	$ 22,104,349	$ 10,973,571	$ 11,130,778	$ 2,014,759,208
July	2004	$ 2,014,759,208	$ 22,104,349	$ 10,913,279	$ 11,191,070	$ 2,003,568,138
August	2004	$ 2,003,568,138	$ 22,104,349	$ 10,852,661	$ 11,251,688	$ 1,992,316,450
September	2004	$ 1,992,316,450	$ 22,104,349	$ 10,791,714	$ 11,312,635	$ 1,981,003,815
October	2004	$ 1,981,003,815	$ 22,104,349	$ 10,730,437	$ 11,373,912	$ 1,969,629,903
November	2004	$ 1,969,629,903	$ 22,104,349	$ 10,668,829	$ 11,435,520	$ 1,958,194,383
December	2004	$ 1,958,194,383	$ 22,104,349	$ 10,606,886	$ 11,497,463	$ 1,946,696,920
January	2005	$ 1,946,696,920	$ 22,104,349	$ 10,544,608	$ 11,559,741	$ 1,935,137,179
February	2005	$ 1,935,137,179	$ 22,104,349	$ 10,481,993	$ 11,622,356	$ 1,923,514,823
March	2005	$ 1,923,514,823	$ 22,104,349	$ 10,419,039	$ 11,685,310	$ 1,911,829,513
April	2005	$ 1,911,829,513	$ 22,104,349	$ 10,355,743	$ 11,748,606	$ 1,900,080,907
May	2005	$ 1,900,080,907	$ 22,104,349	$ 10,292,105	$ 11,812,244	$ 1,888,268,663
June	2005	$ 1,888,268,663	$ 22,104,349	$ 10,228,122	$ 11,876,227	$ 1,876,392,436

July	2005	$ 1,876,392,436	$ 22,104,349	$ 10,163,792	$ 11,940,557	$ 1,864,451,879
August	2005	$ 1,864,451,879	$ 22,104,349	$ 10,099,114	$ 12,005,235	$ 1,852,446,644
September	2005	$ 1,852,446,644	$ 22,104,349	$ 10,034,086	$ 12,070,263	$ 1,840,376,381
October	2005	$ 1,840,376,381	$ 22,104,349	$ 9,968,705	$ 12,135,644	$ 1,828,240,737
November	2005	$ 1,828,240,737	$ 22,104,349	$ 9,902,971	$ 12,201,378	$ 1,816,039,359
December	2005	$ 1,816,039,359	$ 22,104,349	$ 9,836,880	$ 12,267,469	$ 1,803,771,890
January	2006	$ 1,803,771,890	$ 22,104,349	$ 9,770,431	$ 12,333,918	$ 1,791,437,972
February	2006	$ 1,791,437,972	$ 22,104,349	$ 9,703,622	$ 12,400,727	$ 1,779,037,245
March	2006	$ 1,779,037,245	$ 22,104,349	$ 9,636,452	$ 12,467,897	$ 1,766,569,348
April	2006	$ 1,766,569,348	$ 22,104,349	$ 9,568,917	$ 12,535,432	$ 1,754,033,916
May	2006	$ 1,754,033,916	$ 22,104,349	$ 9,501,017	$ 12,603,332	$ 1,741,430,584
June	2006	$ 1,741,430,584	$ 22,104,349	$ 9,432,749	$ 12,671,600	$ 1,728,758,984
July	2006	$ 1,728,758,984	$ 22,104,349	$ 9,364,111	$ 12,740,238	$ 1,716,018,746
August	2006	$ 1,716,018,746	$ 22,104,349	$ 9,295,102	$ 12,809,247	$ 1,703,209,499
September	2006	$ 1,703,209,499	$ 22,104,349	$ 9,225,718	$ 12,878,631	$ 1,690,330,868
October	2006	$ 1,690,330,868	$ 22,104,349	$ 9,155,959	$ 12,948,390	$ 1,677,382,478
November	2006	$ 1,677,382,478	$ 22,104,349	$ 9,085,822	$ 13,018,527	$ 1,664,363,951
December	2006	$ 1,664,363,951	$ 22,104,349	$ 9,015,305	$ 13,089,044	$ 1,651,274,907
January	2007	$ 1,651,274,907	$ 22,104,349	$ 8,944,406	$ 13,159,943	$ 1,638,114,964
February	2007	$ 1,638,114,964	$ 22,104,349	$ 8,873,123	$ 13,231,226	$ 1,624,883,738
March	2007	$ 1,624,883,738	$ 22,104,349	$ 8,801,454	$ 13,302,895	$ 1,611,580,843
April	2007	$ 1,611,580,843	$ 22,104,349	$ 8,729,396	$ 13,374,953	$ 1,598,205,890
May	2007	$ 1,598,205,890	$ 22,104,349	$ 8,656,949	$ 13,447,400	$ 1,584,758,490
June	2007	$ 1,584,758,490	$ 22,104,349	$ 8,584,108	$ 13,520,241	$ 1,571,238,249
July	2007	$ 1,571,238,249	$ 22,104,349	$ 8,510,874	$ 13,593,475	$ 1,557,644,774
August	2007	$ 1,557,644,774	$ 22,104,349	$ 8,437,243	$ 13,667,106	$ 1,543,977,668
September	2007	$ 1,543,977,668	$ 22,104,349	$ 8,363,212	$ 13,741,137	$ 1,530,236,531
October	2007	$ 1,530,236,531	$ 22,104,349	$ 8,288,781	$ 13,815,568	$ 1,516,420,963
November	2007	$ 1,516,420,963	$ 22,104,349	$ 8,213,947	$ 13,890,402	$ 1,502,530,561
December	2007	$ 1,502,530,561	$ 22,104,349	$ 8,138,707	$ 13,965,642	$ 1,488,564,919
January	2008	$ 1,488,564,919	$ 22,104,349	$ 8,063,060	$ 14,041,289	$ 1,474,523,630
February	2008	$ 1,474,523,630	$ 22,104,349	$ 7,987,003	$ 14,117,346	$ 1,460,406,284
March	2008	$ 1,460,406,284	$ 22,104,349	$ 7,910,534	$ 14,193,815	$ 1,446,212,469
April	2008	$ 1,446,212,469	$ 22,104,349	$ 7,833,651	$ 14,270,698	$ 1,431,941,771
May	2008	$ 1,431,941,771	$ 22,104,349	$ 7,756,351	$ 14,347,998	$ 1,417,593,773
June	2008	$ 1,417,593,773	$ 22,104,349	$ 7,678,633	$ 14,425,716	$ 1,403,168,057
July	2008	$ 1,403,168,057	$ 22,104,349	$ 7,600,494	$ 14,503,855	$ 1,388,664,202
August	2008	$ 1,388,664,202	$ 22,104,349	$ 7,521,931	$ 14,582,418	$ 1,374,081,784
September	2008	$ 1,374,081,784	$ 22,104,349	$ 7,442,943	$ 14,661,406	$ 1,359,420,378
October	2008	$ 1,359,420,378	$ 22,104,349	$ 7,363,527	$ 14,740,822	$ 1,344,679,556
November	2008	$ 1,344,679,556	$ 22,104,349	$ 7,283,681	$ 14,820,668	$ 1,329,858,888
December	2008	$ 1,329,858,888	$ 22,104,349	$ 7,203,402	$ 14,900,947	$ 1,314,957,941
January	2009	$ 1,314,957,941	$ 22,104,349	$ 7,122,689	$ 14,981,660	$ 1,299,976,281
February	2009	$ 1,299,976,281	$ 22,104,349	$ 7,041,538	$ 15,062,811	$ 1,284,913,470
March	2009	$ 1,284,913,470	$ 22,104,349	$ 6,959,948	$ 15,144,401	$ 1,269,769,069
April	2009	$ 1,269,769,069	$ 22,104,349	$ 6,877,916	$ 15,226,433	$ 1,254,542,636
May	2009	$ 1,254,542,636	$ 22,104,349	$ 6,795,439	$ 15,308,910	$ 1,239,233,726
June	2009	$ 1,239,233,726	$ 22,104,349	$ 6,712,516	$ 15,391,833	$ 1,223,841,893
July	2009	$ 1,223,841,893	$ 22,104,349	$ 6,629,144	$ 15,475,205	$ 1,208,366,688
August	2009	$ 1,208,366,688	$ 22,104,349	$ 6,545,320	$ 15,559,029	$ 1,192,807,659
September	2009	$ 1,192,807,659	$ 22,104,349	$ 6,461,041	$ 15,643,308	$ 1,177,164,351
October	2009	$ 1,177,164,351	$ 22,104,349	$ 6,376,307	$ 15,728,042	$ 1,161,436,309
November	2009	$ 1,161,436,309	$ 22,104,349	$ 6,291,113	$ 15,813,236	$ 1,145,623,073
December	2009	$ 1,145,623,073	$ 22,104,349	$ 6,205,458	$ 15,898,891	$ 1,129,724,182
January	2010	$ 1,129,724,182	$ 22,104,349	$ 6,119,339	$ 15,985,010	$ 1,113,739,172
February	2010	$ 1,113,739,172	$ 22,104,349	$ 6,032,754	$ 16,071,595	$ 1,097,667,577
March	2010	$ 1,097,667,577	$ 22,104,349	$ 5,945,699	$ 16,158,650	$ 1,081,508,927
April	2010	$ 1,081,508,927	$ 22,104,349	$ 5,858,173	$ 16,246,176	$ 1,065,262,751
May	2010	$ 1,065,262,751	$ 22,104,349	$ 5,770,173	$ 16,334,176	$ 1,048,928,575
June	2010	$ 1,048,928,575	$ 22,104,349	$ 5,681,696	$ 16,422,653	$ 1,032,505,922
July	2010	$ 1,032,505,922	$ 22,104,349	$ 5,592,740	$ 16,511,609	$ 1,015,994,313
August	2010	$ 1,015,994,313	$ 22,104,349	$ 5,503,303	$ 16,601,046	$ 999,393,267
September	2010	$ 999,393,267	$ 22,104,349	$ 5,413,380	$ 16,690,969	$ 982,702,298
October	2010	$ 982,702,298	$ 22,104,349	$ 5,322,971	$ 16,781,378	$ 965,920,920
November	2010	$ 965,920,920	$ 22,104,349	$ 5,232,072	$ 16,872,277	$ 949,048,643
December	2010	$ 949,048,643	$ 22,104,349	$ 5,140,680	$ 16,963,669	$ 932,084,974
January	2011	$ 932,084,974	$ 22,104,349	$ 5,048,794	$ 17,055,555	$ 915,029,419
February	2011	$ 915,029,419	$ 22,104,349	$ 4,956,409	$ 17,147,940	$ 897,881,479
March	2011	$ 897,881,479	$ 22,104,349	$ 4,863,525	$ 17,240,824	$ 880,640,655
April	2011	$ 880,640,655	$ 22,104,349	$ 4,770,137	$ 17,334,212	$ 863,306,443

May	2011	$ 863,306,443	$ 22,104,349	$ 4,676,243	$ 17,428,106	$ 845,878,337
June	2011	$ 845,878,337	$ 22,104,349	$ 4,581,841	$ 17,522,508	$ 828,355,829
July	2011	$ 828,355,829	$ 22,104,349	$ 4,486,927	$ 17,617,422	$ 810,738,407
August	2011	$ 810,738,407	$ 22,104,349	$ 4,391,500	$ 17,712,849	$ 793,025,558
September	2011	$ 793,025,558	$ 22,104,349	$ 4,295,555	$ 17,808,794	$ 775,216,764
October	2011	$ 775,216,764	$ 22,104,349	$ 4,199,091	$ 17,905,258	$ 757,311,506
November	2011	$ 757,311,506	$ 22,104,349	$ 4,102,104	$ 18,002,245	$ 739,309,261
December	2011	$ 739,309,261	$ 22,104,349	$ 4,004,592	$ 18,099,757	$ 721,209,504
January	2012	$ 721,209,504	$ 22,104,349	$ 3,906,551	$ 18,197,798	$ 703,011,706
February	2012	$ 703,011,706	$ 22,104,349	$ 3,807,980	$ 18,296,369	$ 684,715,337
March	2012	$ 684,715,337	$ 22,104,349	$ 3,708,875	$ 18,395,474	$ 666,319,863
April	2012	$ 666,319,863	$ 22,104,349	$ 3,609,233	$ 18,495,116	$ 647,824,747
May	2012	$ 647,824,747	$ 22,104,349	$ 3,509,051	$ 18,595,298	$ 629,229,449
June	2012	$ 629,229,449	$ 22,104,349	$ 3,408,326	$ 18,696,023	$ 610,533,426
July	2012	$ 610,533,426	$ 22,104,349	$ 3,307,056	$ 18,797,293	$ 591,736,133
August	2012	$ 591,736,133	$ 22,104,349	$ 3,205,237	$ 18,899,112	$ 572,837,021
September	2012	$ 572,837,021	$ 22,104,349	$ 3,102,867	$ 19,001,482	$ 553,835,539
October	2012	$ 553,835,539	$ 22,104,349	$ 2,999,943	$ 19,104,406	$ 534,731,133
November	2012	$ 534,731,133	$ 22,104,349	$ 2,896,460	$ 19,207,889	$ 515,523,244
December	2012	$ 515,523,244	$ 22,104,349	$ 2,792,418	$ 19,311,931	$ 496,211,313
January	2013	$ 496,211,313	$ 22,104,349	$ 2,687,811	$ 19,416,538	$ 476,794,775
February	2013	$ 476,794,775	$ 22,104,349	$ 2,582,638	$ 19,521,711	$ 457,273,064
March	2013	$ 457,273,064	$ 22,104,349	$ 2,476,896	$ 19,627,453	$ 437,645,611
April	2013	$ 437,645,611	$ 22,104,349	$ 2,370,580	$ 19,733,769	$ 417,911,842
May	2013	$ 417,911,842	$ 22,104,349	$ 2,263,689	$ 19,840,660	$ 398,071,182
June	2013	$ 398,071,182	$ 22,104,349	$ 2,156,219	$ 19,948,130	$ 378,123,052
July	2013	$ 378,123,052	$ 22,104,349	$ 2,048,167	$ 20,056,182	$ 358,066,870
August	2013	$ 358,066,870	$ 22,104,349	$ 1,939,529	$ 20,164,820	$ 337,902,050
September	2013	$ 337,902,050	$ 22,104,349	$ 1,830,303	$ 20,274,046	$ 317,628,004
October	2013	$ 317,628,004	$ 22,104,349	$ 1,720,485	$ 20,383,864	$ 297,244,140
November	2013	$ 297,244,140	$ 22,104,349	$ 1,610,072	$ 20,494,277	$ 276,749,863
December	2013	$ 276,749,863	$ 22,104,349	$ 1,499,062	$ 20,605,287	$ 256,144,576
January	2014	$ 256,144,576	$ 22,104,349	$ 1,387,450	$ 20,716,899	$ 235,427,677
February	2014	$ 235,427,677	$ 22,104,349	$ 1,275,233	$ 20,829,116	$ 214,598,561
March	2014	$ 214,598,561	$ 22,104,349	$ 1,162,409	$ 20,941,940	$ 193,656,621
April	2014	$ 193,656,621	$ 22,104,349	$ 1,048,973	$ 21,055,376	$ 172,601,245
May	2014	$ 172,601,245	$ 22,104,349	$ 934,923	$ 21,169,426	$ 151,431,819
June	2014	$ 151,431,819	$ 22,104,349	$ 820,256	$ 21,284,093	$ 130,147,726
July	2014	$ 130,147,726	$ 22,104,349	$ 704,967	$ 21,399,382	$ 108,748,344
August	2014	$ 108,748,344	$ 22,104,349	$ 589,054	$ 21,515,295	$ 87,233,049
September	2014	$ 87,233,049	$ 22,104,349	$ 472,512	$ 21,631,837	$ 65,601,212
October	2014	$ 65,601,212	$ 22,104,349	$ 355,340	$ 21,749,009	$ 43,852,203
November	2014	$ 43,852,203	$ 22,104,349	$ 237,533	$ 21,866,816	$ 21,985,387
December	2014	$ 21,985,387	$ 22,104,349	$ 119,088	$ 21,985,261	$ 126

ATTACHMENT C

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE ENERGY MASTER PLAN PHASE II PROCEEDING TO INVESTIGATE THE FUTURE OF THE ELECTRIC POWER INDUSTRY	))))	BPU Docket Nos. EO97070461 EO97070462 EO97070463

AFFIDAVIT OF MICHAEL D. DIRMEIER

STATE OF CONNECTICUT)
) ss. Ridgefield
COUNTY OF FAIRFIELD)

Michael D. Dirmeier, of full age, being duly sworn, according to law, deposes and says:

1. I am a public utility consultant and a principal with Georgetown Consulting Group, Inc., 456 Main Street, Ridgefield, Connecticut, 06877. I have previously testified before regulatory commissions in Alabama, Arkansas, Colorado, Florida, Georgia, Kentucky, Louisiana, Maine, Maryland, Mississippi, New Jersey, New Mexico, New York, North Carolina, Oklahoma, Pennsylvania, South Carolina, Tennessee, Vermont, Virginia, the U.S. Virgin Islands, the District of Columbia, the Federal Energy Regulatory Commission and the U.S. Nuclear Regulatory Commission.

   Before joining Georgetown Consulting Group, Inc., I was employed by Touche Ross and Co. and the Bendix Corporation. My consulting experience includes operations reviews, design and implementation of procedures and product-line analysis. I have prepared and made presentations regarding the Tax Reform Act of 1986. My corporate work included capital budgeting, investment analysis, financial modeling and planning, analysis of acquisitions and divestitures, and preparation of financial reports for the Board of Directors.

   I graduated from Texas A&M University in 1971 with a Bachelor of Science Degree in physics. I received a Master of Business Administration Degree in finance from the University of Chicago in 1973. In 1979, I received a Certificate in Management Accounting, which is a professional certification for management accountants and financial managers awarded by the Institute of Certified Management Accountants.

2. I was a witness in the captioned proceedings, sponsored by the Division of the Ratepayer Advocate. I have testified or filed testimony in a number of dockets in other jurisdictions with respect to restructure, addressing such issues as the economic effects of restructure, stranded cost, affiliate code of conduct and regulatory policy.

3. I make this affidavit on behalf of the Division of the Ratepayer Advocate concerning the market value of PSE&G's electric generation resources and the extent to which the PSE&G Stipulation's "opportunity" to recover $600 million of non-securitized stranded cost is actually a guaranteed recovery.

4. On March 17, 1999, PSE&G filed a Stipulation ["PSE&G Stipulation"] with the Board. This Stipulation has not been entered into by all parties to the proceeding. The PSE&G Stipulation includes agreements concerning the terms and conditions under which PSE&G would transfer, to an affiliate, its generating stations and "all contracts (except for the NUG contracts) associated with the electric generating business, including, but not limited to, wholesale electric purchase and sales agreements, fuel contracts, real and personal property interests, and other contractual rights and liabilities . . ." [PSE&G Stipulation, paragraph 27]

   These proposals are inconsistent with the proposals that were made by PSE&G in its filing and covered in the Record. PSE&G's plans concerning transfer to a subsidiary were incomplete at the time of hearing:

   > Q Is it the Company's plan to transfer its own generation assets to an unregulated subsidiary?
   > A That determination hasn't been made yet. It would be a separate entity, but we haven't developed exactly what organizational form that would be.
   >
   > Q When you say you are not clear about what organizational entity, you were referring specifically to my use of the word "subsidiary"?
   > A Yes.

   Transcript 2/9/98, TR-86-87.

   The above establishes that PSE&G's proposal to transfer its generation was, at most, an incomplete proposal. The PSE&G Stipulation transforms that incomplete proposal into a complete *fait accompli*. The issue of the transfer *to a subsidiary* of PSE&G's generation assets has not been litigated in this proceeding.

5. PSE&G's filed proposal involved removing generation from the regulated utility company at the conclusion of a seven-year transition period. The PSE&G Stipulation calls for the immediate transfer of generation, the transfer of all non-NUG related generation contracts, and the creation of a series of contracts between PSE&G and Genco. None of these issues were litigated or contemplated during the proceeding, because PSE&G had proposed none of these transfers.

6. There are a number of issues that should be resolved with respect to a transfer of utility assets to an affiliate. While some of these issues may have been resolved, at least in the minds of those entering into the PSE&G Stipulation, it is my understanding that few if any of them have been discussed in the Record. These issued include: (I) the proper valuation of assets to be transferred to Genco *at this time* rather than seven years in the future; (ii) the terms and

conditions under which Genco would provide power to PSE&G; (iii) the treatment of any value received for any Genco sales of power to customers other than PSE&G; (iv) the payments between PSE&G and Genco for ancillary services; (v) the terms and conditions under which Genco would be allowed, either now or in the future, to compete for retail customers in PSE&G's service territory; (vi) the rights of competitors to purchase surplus capacity and energy from Genco; (vii) any potential premium to be charged to Genco for contracts that it assumes from PSE&G; (viii) the sharing of resources (*e.g.*, information, systems, employees) between Genco and PSE&G.

7. In addition, in this proceeding, because so many of the values reflected in the PSE&G Stipulation are not based on the record, it would be appropriate to obtain at least a minimum amount of information such as:

   1. an explanation, including depiction of cash flows, of the proposed transaction between PSE&G and Genco concerning the $600 million of non-securitized stranded cost.

   2. the accounting on Genco's books for:

      A. the source and receipt of funds from which to make the initial $600 million payment to PSE&G;
      B. the payment to be made to PSE&G;
      C. the receipt of funds from PSE&G relating to collections of the $600 million, by type [retail adder, explicit MTC, depreciation reserve amortization].

   3. the accounting on PSE&G's books for:

      A. the receipt of funds from Genco for the initial $600 million payment;
      B. the payments to be made to Genco relating to collections of the $600 million, by type [retail adder, explicit MTC, depreciation reserve amortization].

8. Attachment 4 to the Stipulation indicates that Genco will pay $2.368 billion for PSE&G's generation assets. However, since Genco will be entitled to the MTC revenue stream, which is a virtually guaranteed $600 million recovery, the actual effective transfer price is $1.768 billion.

9. The Record in this proceeding reflects a number of estimates of market value and stranded cost. The PSE&G estimate of market value is by far the lowest estimate in the Record.

   The Initial Brief of the Division of the Ratepayer Advocate ["DRA"] reflects a stranded generation cost of $1.898 billion [Schedule 1 page 1, attached to Brief]. As compared to PSE&G's book value of $5.068 billion, the market value consistent with the DRA position is $3.17 billion. The PSE&G Stipulation market value of $1.768 billion is $1.4 billion *less* than the market value consistent with the DRA position.

The Stranded Cost Brief and Appendix of the Staff of the Board of Public Utilities, dated April 15, 1998, reflects a stranded cost estimate of $2.9 billion before mitigation [page 50]. The Staff market value is $2.2 billion. The PSE&G Stipulation market value is $400 million *less* than the market value consistent with the Staff position.

10. A significant amount of data has become available since the close of the Record concerning the sales of generating plants, which is relevant to the proper valuation of assets to be transferred to Genco and to the valuation of stranded cost.

    On November 12, 1998, Resource Data International, Inc. ("RDI") published an *Energy Insight* report, "Power Plant Sales Yield Market Trends," which begins by stating that, in the last 18 months, 35,000 MW of capacity has been sold in North America for $16.5 billion [see Attachment B]. That amounts to approximately $471 per kW. In contrast, PSE&G's valuation at $1.768 billion, for 9,556 MW of capacity to be transferred to Genco, is $185 per kW, or less than one-half the actual average price for the sales reflected in the RDI report. The appropriate valuation, reflected on Attachment A, amounts to $304 per kW.

11. Attachment A reflects an estimate of the market value of PSE&G's generating resources based on the average values for transactions involving the sale of coal, oil & gas and nuclear units reflected in RDI's November 12, 1998 report. A reasonable market-based estimate of market value is $2.9 billion. After consideration of income taxes that would be applicable to a sale, the net after-tax proceeds to PSE&G from a sale to Genco at $2.9 billion would be approximately $2.4 billion. The consistent after-tax stranded cost is $2.7 billion.

    The RDI average value provides, at best, a conservative measure of the value of PSE&G's generation. As noted in the RDI report, gas and oil plant values are currently the highest in the Northeast. In another *Energy Insight* report concerning GPU's sale of Homer City at $955 per kW, RDI noted that a factor in the sale was access to "highly lucrative eastern markets," markets into which Genco is going to be selling its generating output ["Coal Plant Sales Set High Benchmark," August 4, 1998. See Attachment C].

12. The $2.9 billion market value, computed on Attachment A, comes most closely to achieving the most appropriate valuation, as indicated on page 54 of Staff's April 15, 1998 Stranded Cost Brief:

    > As discussed previously, an auction of generating assets is clearly superior to an administrative determination of market value, for purposes of establishing a definitive level of stranded costs. Through a bidding/divestiture process, prospective purchasers are required to "put their money where their mouths are" with respect to expectations for future market conditions; moreover, perceived intrinsic and ancillary values from the perspective of individual purchasers in the marketplace are captured in a way that cannot be modeled.

Note: The measures of market value included in this affidavit are not adjusted for any *pro forma* tax effects of an assumed sale. While such effects may be appropriate in valuing after-tax stranded cost, the focus of the comments herein is on the valuation of the transfer to Genco. Furthermore, all amounts have been stated on a pre-tax basis for comparability purposes, unless otherwise noted.

13. The $1.768 billion market value underlying the PSE&G Stipulation is $1.1 billion below the fair market value of PSE&G's generating assets, based on Attachment A. By including an under-valuation of PSE&G's assets, the PSE&G Stipulation results in an under-valuation of assets on Genco's books, to the detriment of a future hoped-for competitive market. It also produces an overstatement of stranded cost, to the detriment of PSE&G's customers who are required to pay for stranded cost.

14. Paragraph 13 [page 11] of the PSE&G Stipulation provides that PSE&G is to have:

> the opportunity to recover up to $600 million of its unsecuritized generation stranded costs on a net present value (8.42% discount rate) net of tax basis over the Transition Period. This recovery is to be accomplished via a 2 mill per kWh retail adder, an explicit Market Transition Charge (MTC), exclusive of the NTC . . .and the amount funded by the excess distribution depreciation reserve amortization.

Paragraph 4 of the PSE&G Stipulation indicates that the depreciation *amortization* would be $125 million in 2000, $125 million in 2001, $135 million in 2002 and $183.7 million in 2003. Using the 8.42% discount rate contained in the PSE&G Stipulation, this amortization has a net present value of $458 million. Thus, the Stipulation *guarantees* recovery of an indisputable 76% of the amount that PSE&G is supposed to have an opportunity to recover.

The amount of recovery resulting from the 2 mill per kWh retail adder depends on the amount of PSE&G's load that is retained by PSE&G over the four-year transition period. Assuming that PSE&G loses 5% of its load immediately upon the August 1, 1999 implementation of retail competition, and an additional 5% of its load on January 1 of each of the years 2000 through 2003, PSE&G will retain a nominal $271 million from the retail adder, with an after-tax net present value in excess of $120 million. Thus, with conservative assumptions about the pace of competitive losses, the PSE&G Stipulation guarantees recovery of another 20% of the $600 million that PSE&G is supposed to have an "opportunity" to recover.

In combination, the items above guarantee recovery of 96% or more of the $600 million that PSE&G is supposed to have an "opportunity" to recover. These guaranteed recoveries could be used to offset the MTC charge to ratepayers or to sustain rate reductions beyond the transition period.

Michael D. Dirmeier

Michael D. Dirmeier

SUBSCRIBED AND SWORN to before me this 29th day of March, 1999 by Michael D. Dirmeier.

Wesley A. Wood

My Commission Expires:
August 31, 1999

Attachment A

Public Service Electric & Gas Company
Market Valuation at Achieved Sales Prices
($000s)

	Capacity type	MW	RDI Market	Market Value	
1.	Oil	1,531	$ 370	$ 566,470	
2.	Less: Linden oil	(415)	370	(153,550)	
3.	Less: Kearny oil	(280)	370	(103,600)	
4.	Coal - NJ	1,248	518	646,464	
5.	Coal - PA	770	518	398,860	
6.	CT	2,724	370	1,007,880	
7.	CC	922	370	341,140	
8.	Diesel	5	0	0	
9.	Pumped storage	200	0	120,000	(1)
10.	Fossil	6,705		$ 2,823,664	
11.	Nuclear - NJ	1,921	28	$ 53,788	
12.	Nuclear - Pa	930	28	26,040	
13.	Nuclear	2,851		$ 79,828	
14.	Total market value	9,556		$ 2,903,492	

		Fossil	Nuclear	Total
15.	Market	$ 2,823,664	$ 79,828	$ 2,903,492
16.	Tax basis	1,028,135	570,663	1,598,798
17.	Pre-tax gain	$ 1,795,529	$ (490,835)	$ 1,304,694
18.	Tax rate	41.0%	41.0%	41.0%
19.	Tax liability	$ 736,167	$ (201,242)	$ 534,925
20.	Market	$ 2,823,664	$ 79,828	$ 2,903,492
21.	Net book	1,827,333	3,252,709	5,080,042
22.	Tax liability	736,167	(201,242)	534,925
23.	Stranded (cost) benefit	$ 260,164	$ (2,971,639)	$ (2,711,475)

(1) Pumped storage is valued at the $120 million amount at which GPU has proposed to sell its 50% share of Yards Creek.

Attachment B

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Thursday, November 12, 1998

Power Plant Sales Yield Market Trends

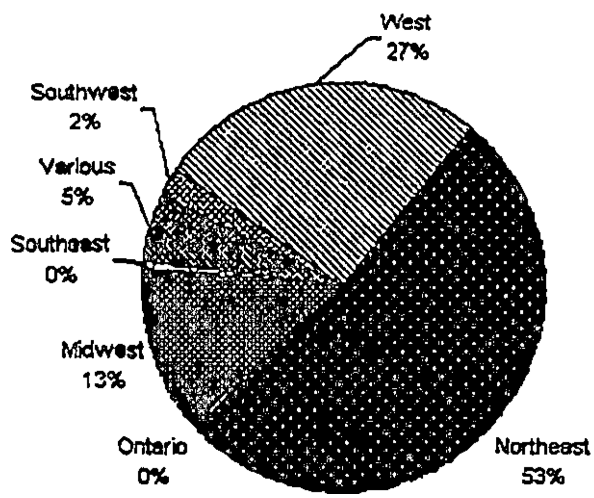
Asset Sales in 18 Months Have Amassed $16 Billion in Value

NUG Plants Command a Premium

Sithe Energies Buys 1-in-3 Northeast Plants

Summarizing more than 18 months that power generating assets have been actively bought and sold in North American markets, approximately 35,000MW of capacity has been sold for $16.5 billion. More than half of all sales have taken place in the Northeastern U.S. Roughly one-quarter of all sales have occurred in the West and another 13% in the Midwest, the result there largely of sales by Commonwealth Edison and by institutional owners of a Minnesota plant.

Asset Sales by Region



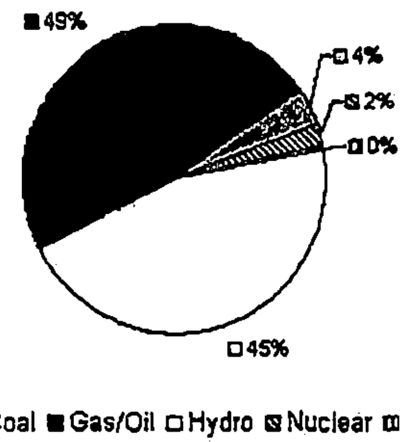
CLICK ON MAP TO VIEW FULL IMAGE

In addition, only a few repeat buyers have been active in the markets so far. Most notable among these are Sithe Energies (which bought assets from both GPU Inc., and BECO), FPL Group (which bought assets from Central Maine Power and Kenetech Windpower), AES Corp. (which bought assets from New York State Electric & Gas and Southern California Edison) and PP&L Global (which bought assets from both Bangor Hydroelectric and Montana Power). Southern Energy reported taking part in several auctions before it came out high bidder last May for assets sold by Commonwealth Energy System and Eastern Utility Associates. Equally interesting is the companies that are not dominating the asset auctions. US Generating and Edison International, for example, have made only one purchase each. Conversely, Sithe *Energies has bought one out of every three generating units sold in* the Northeast.

"Plants fueled by coal and natural gas/oil have dominated the asset sales to date."

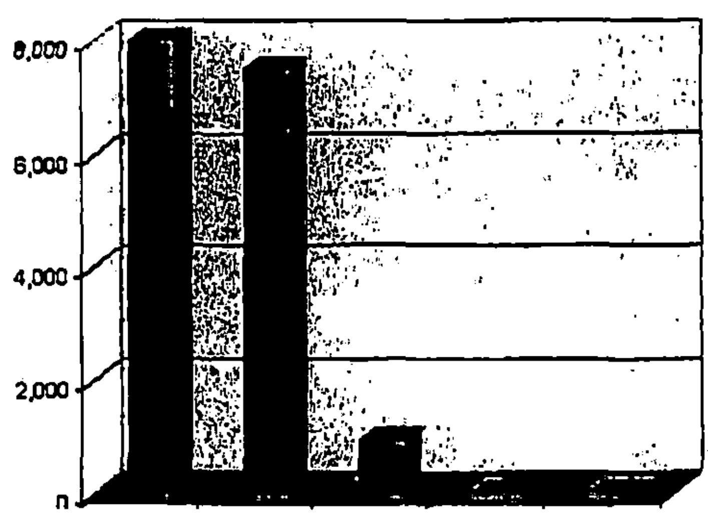
Plants fueled by coal and natural gas/oil have dominated the asset sales to date. Although aggregating capacities is sometimes difficult because several sales have been "packages" with several plant types, more than 16,000 MW of coal-fired generation has been sold, and nearly 17,000 MW of gas-fired generation.

Generating Asset Sales by Type of Fuel



Altogether, coal-fired plants have amassed just under $8 billion in value. Sales of gas-fired plants amassed nearly $7.5 billion in value. *Altogether, nearly $16.5 billion in value has been amassed* through all generating asset sales to date.

Total Value of Plant Acquisitions by Fuel Type ($ millions)



"...coal plants have brought an average of $518/kW."

$518/kW.
"

Viewed on a dollars-per-kilowatt basis, coal plants have brought an average of $518/kW. At the upper end of the scale, high-value coal plants have brought about $1,000/kW. These include Edison Mission Energy's purchase of the Homer City plant, and Sithe Energie's purchase of minority interests in the Keystone and Conemaugh plants. These represent low-cost plants operating in high-priced markets.

Value of Generation Asset Sales ($/kW)

Medium-value coal plants have gone for $300 to $700/kW. These include Colstrip, Kintigh and the smaller GPU and NYSEG coal plants. These tend to be either higher-cost plants or plants operating in lower-priced markets.

The next highest-value plants are hydro. These have sold for an *average of* $507/kW. A key advantage to these plants is their low operating costs. The single largest purchase of hydro assets has been FPL Group's $846 million purchase last January of 1,165 MW of mostly hydro generating capacity from Central Maine Power. Those assets brought almost $714/kW.

Gas and oil plants on average have brought just under $370/kW. Their value is currently the highest in the Northeast. Gas-fired plants in California, meanwhile, have sold within a range of $29 to $200/kW.

Only a limited amount of nuclear-fired capacity has sold to date. Three Mile Island #2 brought $28/kW and an percentage interest in Seabrook brought close to $100/kW. Renewable energy, in the form of 160 MW of wind capacity, sold for $237.5/kW.

Interestingly, non-utility generator assets have attracted some of the highest prices, selling for as much as $900 to $1,400/kW. The value of these assets depend largely on existing contracts. Enron Capital & Trade earlier this month paid almost $1,400/kW for three gas-fired cogeneration plants near New York City, which have long-term contracts with Consolidated Edison and others.

Plant values are determined by a number of factors. Chief among these are:

- Projections of future prices.
- Plant costs, and fuel costs in particular. Plants having low fuel costs or the potential for low fuel costs will likely bring higher values than plants having high fuel costs.

- Existing O&M costs are only an indication of future costs; many new owners plan operational or management changes to reduce costs.
- Some plants sell for less because they require considerable investment; some may face future environmental retrofits, which may affect their value.
- In some sales, a portion of the payment is to gain access to future plant development sites.
- Competition and competitor action are also important considerations. If relatively few competitive generators exist in a market, a prospective asset buyer may see strong prices for power. Likewise, if few competitive sites exist for new plants, then existing plants sites may be even more valuable.

Competing plants also help determine market prices for power. As a result, low-cost plants (including many coal-fired plants) in high-cost markets (where most other plants operate on high-cost fuel) will sell for higher values. Gas-fired plants having access to lower-than-average-cost gas will also command higher values.

Related Insights of Interest

11/10/98 IPP's Capture Major Shares of Northeast Generation Markets
11/3/98 PP&L Global Enters Western Markets with $1.6 Billion Asset Buy
11/2/98 Enron Unit in $1.45 Billion Deal for New Jersey Power Plants
10/19/98 Duquesne Light May Come Out on Top in Asset Swap
10/12/98 RDI Outlook Says 186,176 MW of New Generation Required by 2010
10/8/98 Outlook for Power in the U.S.
10/6/98 The High Cost of NUG Power
8/4/98 Coal Plant Sales Set High Benchmark
7/20/98 AmerGen Energy's Sharp Pencil Nets It a Nuke
7/15/98 Merchant Power Plant Development Set to Accelerate Through 2001

Analysis by David Wagman and Chris Neil
Dwagman@resdata.com and cneil@resdata.com

Yesterday's Analysis

Beginning of Story

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Search & Archives

Market Indicators

SEC Filings

RDI Homepage

Feedback

What's New

HOME

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Tuesday, August 4, 1998

Coal Plant Sales Set High Benchmark

Homer City Brings High $/kW Price

Environmental Compliance Could Add to Investment

National Market Gains a Benchmark for Coal Plant Values

Two sets of generating asset sales announced yesterday will help set a benchmark market value for coal-fired electric generating assets.

GPU Inc. and New York State Electrio and Gas (NYSEG) jointly sold the 1,884 MW Homer City plant near Pittsburgh to Edison Mission Energy for $1.8 billion, or $955.4/kW.

Also yesterday, AES Corp. won a bid to acquire six coal-fired electric generating plants from NGE Generation Inc., an affiliate of NYSEG for approximately $950 million, or $667.1/kW. The facilities represent the bulk of NYSEG's coal-fired generation assets and were auctioned as part of NYSEG's implementation of its restructuring plan in accordance with New York's introduction of wholesale and retail competition into the state's electricity generation market. The six facilities, in western and west-central New York, are Kintigh (675 MW), Milliken (306 MW), Goudey (126 MW), Greenidge (161 MW), Hickling (85 MW) and Jennison (71 MW).

CLICK ON MAP TO VIEW FULL IMAGE

Record Price

A record was set, however, with tha sale of the Homer City generating station near Pittsburgh. Edison Mission Energy, a unit of California-based Edison International, agreed to pay $955.4/kW for the plant. The sale price is the highest to date on a dollars-per-kilowatt basis, and potentially sets a high standard for the sale of other highly efficient coal-fired assets.

By contrast, two weeks ago, GPU sold the 810 Three Mile Island

Edison Mission Energy...agreed to pay $955.4/kW for the plant

By contrast, two weeks ago, GPU sold the 810 Three Mile Island Unit 1 nuclear generating station to AmerGen Energy for $28/kW, one of the lowest sales prices to date. (See Energy Insight, AmerGen Energy's Sharp Pencil Nets It a Nuke," July 20, 1998.)

Recently Announced Generating Asset Sales
Through August 3, 1998

Company	Assets	Purchased MW	Price/kW
Edison Mission Energy	**Homer City**	**1,884**	**$955**
FPL Group	CMP	1,185	$790
AES Corp.	**NYSEG (excl. Homer City)**	**1,424**	**$667**
Southern Energy	ComEnergy	984	$470
US Generating	NEES	4,000	$377
Sithe Energies	BECO	2,000	$268
Southern Energy	EUA	280	$268
AES Corp.	SoCalEd	3,956	$197
Duke Energy	PG&E	2,645	$189
Houston Industries	SoCalEd	2,276	$104
Great Bay Power	Seabrook (2.9%)	34	$95
NRG/Destec	SoCalEd	1,020	$86
NRG/Destec	SoCalEd	530	$56
Thermo Ekotech	SoCalEd	280	$34
AmerGen Energy	TMI#1	810	$28

Source: Press reports, Resource Data International, Inc.

Jointly owned by subsidiaries of GPU, Inc. and NYSEG, Homer City has direct high voltage access to both the New York Power Pool and the Pennsylvania-New Jersey-Maryland Power Pool, making it a key asset for power sales into highly lucrative eastern markets.

Investment in Homer City is likely to continue, probably of an environmental nature. Edison International could install scrubbing equipment to reduce the plant's emissions. Energy Insight last fall identified the plant as being within 150 miles of a non-attainment area for ozone (see Energy Insight, "Ozone Transport Rule Could Affect Another 145,000 MW," October 16,1997). If scrubbers are installed at the plant, such an investment could cost in the range of $150/kW, or as much as $280 million for the 1,884 MW plant.

A potentially less costly alternative could see the plant's new operators switch coal suppliers to achieve lower sulfur content. Another alternative may be for the plant to blend local Appalachian coal with Powder River Basin coal from Wyoming to achieve even lower sulfur content.

Sulfur dioxide scrubbers have already been installed at the largest NYSEG plants acquired by AES, the Kintigh and Milliken stations.

Homer City's sale is the first for a large, highly efficient coal-fired plant in North America. As such it helps set a benchmark for the market value of other coal-fired plants. During 1996, Homer City generated just under 12.5 million MWh of electricity, and operated at a 75% capacity factor. Its overall production costs were $19.5/MWh. This was somewhat higher than the average cost of production among the largest coal-fired stations in Maryland, New Jersey, New York, Ohio, Pennsylvania and West Virginia.

Homer City generated just under 12.5 million

Largest Coal-Fired Generation Stations

just under 12.5 million MWh of electricity. ”

At the same time, however, Homer City has seen a steady decline in its fuel costs.

Drop in Fuels Costs Aids Capacity Increases

This drop has helped capacity factors climb each year since 1994. This upward trend extended through April 1998, according to the most recent data from Resource Data International, Inc.'s COALdat database.

Both sales announced yesterday are part of the planned divestiture of generating assets by both NYSEG and GPU. Last October, NYSEG announced that part of its restructuring plan filed with the New York Public Service Commission includes the divestiture of its seven coal-fired generating assets and its 18% interest in the Nine Mile Point 2 nuclear generating station. Within days of that announcement, GPU Inc. said it intended to auction off its 5,300 MW of non-nuclear generating capacity and to find a buyer for its Oyster Creek and Three Mile Island nuclear generating stations. No buyer could be found for Oyster Creek, which now faces decommissioning in 2000. Two weeks ago, AmerGen Energy said it would buy the lone operating unit at Three Mile Island.

Related Insights of Interest

7/20/98 AmerGen Energy's Sharp Pencil Nets It a Nuke
7/10/98 Relicense or Close?: How the Numbers Helped Decide the Fate of Two Nukes
7/8/98 Commonwealth Edison to Sell 5,400 MW of Coal Capacity
6/22/98 Green Market Potential: Broader, More Diverse than Advertised
6/18/98 Generation Asset Market Could Complicate Energy Prices
6/15/98 Environmental Factors to Define Next Era?
2/23/98 Regional Haze Rule Could Affect Two-Thirds of Installed Capacity
2/20/98 How Green Is Your Electron
10/16/97 Ozone Transport Rule Could Affect an Additional 145,000MW of Capacity

Analysis by David Wagman
Dwagman@resdata.com

Beginning of Story

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ATTACHMENT D

ATTACHMENT D

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE ENERGY	)	BPU DOCKET Nos.	EO97070461
MASTER PLAN PHASE II PROCEEDING	)		EO9707462
TO INVESTIGATE THE FUTURE	)		EO97070463
OF THE ELECTRIC POWER INDUSTRY	)		

RE: PUBLIC SERVICE ELECTRIC AND GAS COMPANY PROPOSED STIPULATION

AFFIDAVIT OF JOHN S. ROHRBACH

COMMONWEALTH OF PENNSYLVANIA	)	
	)	ss. Harrisburg
COUNTY OF DAUPHIN	)	

John S. Rohrbach, of full age, being duly sworn, according to law, deposes and says:

1. My name is John S. Rohrbach. I am providing this affidavit on behalf of the Mid Atlantic Power Supply Association. My vita is attached.

2. From August 1993 to December 1998 I advised Commissioners John Hanger (August 1993 to June 1998) and Nora Mead Brownell (June 1998 through December 1998) of the Pennsylvania Public Utility Commission on many aspects surrounding the introduction of retail electric competition in Pennsylvania. In particular, I was a participant in the PECO litigation and settlement. As a result of this exposure I can speak to the mathematics and economics of the build-up of the PECO shopping credits and their relevance to the introduction of retail electric choice in the Public Service Electric and Gas ("PSE&G") service territory.

3. The purpose of this affidavit is to explain:

   a. the cost and market factors that must be considered when updating the PECO Shopping Credits for present application to PSE&G;

   b. a comparison of the PSE&G's plan to the Better Choice Settlement Proposal in months 49 to 72;

   c. the underlying financial supporting data for the Better Choice Settlement Proposal;

   d. The record evidence of PSE&G's mitigation opportunities;

PECO Updated Shopping Credits

4. The underlying market forces that made the PECO Shopping Credits acceptable have changed considerably since April 1998. Since the PECO settlement was signed on April 30, 1998, prices in the forward on-peak energy market, as well as the installed capacity (ICAP) market, have risen considerably. While prices in the energy and capacity market are now relatively stable, for the foreseeable future the energy market shows no indication of falling to the levels found when the PECO settlement was reached. Recently the FERC approved a change in the PJM energy market pricing mechanism to allow market-based pricing. Expectation of market-based pricing of energy may have been impounded into the forward market prior to the FERC's March 10, 1999 decision. Similarly, the ICAP forward market, while benefitting from the PJM's establishment of day-ahead and month-ahead auctions, shows no sign of falling back to levels implicit in the PECO shopping credits. While the PSE&G Stipulation's proposed shopping credits are greater than the PECO shopping credits on their face, they are not adequate to support a truly competitive retail market in PSE&G territory. Indeed, on a real basis the PSE&G proposed shopping credits may be lower than the PECO shopping credits.

5. PSE&G asserts that their stipulation's proposed shopping credits (5.03 cents/kWh in 2000, 5.06 cents/kWh in 2001, 5.10 cents/kWh in 2002 and 5.10 cents/kWh in 2003) are higher than the PECO Energy system shopping credit and should be sufficient to foster robust competition in the PSE&G territory. However, given changes in the energy and capacity markets and differences in costs between New Jersey and Pennsylvania it is clear that a minimum 5.4 cents/kWh system shopping credit is needed for PSE&G customers to at least benefit from the receiving the same rate discounts that PECO customers presently enjoy.

6. Changes in the PJM electricity market combined with substantive differences in costs between New Jersey and Pennsylvania support the Better Choice Settlement Proposal's proposed 5.4 cent/kWh system shopping credit. The first reason is that a 5.4 cents/kWh system shopping credit is required for PSE&G in 2000 is that all-hours energy costs are now 13.2% higher than the underlying energy costs in existence when the PECO Settlement shopping credits were established. This shift in the forward energy market would require adding .33 cents/kWh to the PECO System shopping credit to provide PSE&G customers with the same shopping credit value. Additionally, a slight difference in locational energy prices caused by transmission congestion requires an additional adjustment of .05 cents/kWh to the PECO shopping credit to achieve purchasing power parity between PECO and PSE&G.

7. The second necessary adjustment to the PECO system shopping credit is for an increase in the PJM forward ICAP prices from the $30.4 kW-year that is underlying the PECO shop credits in 2000. ICAP prices are expected to be about $37 per kW-year in the PJM forward market; to account for this rise in costs 0.165 cents/kWh must be added to the PECO shopping credits.

8. Thirdly, Gross Receipts Taxes in New Jersey are 36% higher then Pennsylvania. Pennsylvania taxes are 4.4% whereas NJ taxes are 6%. This requires adding about .073 cents to the PECO shopping credit to assure purchasing power parity for PSE&G consumers.

9. Fourth, it appears that PSE&G's PJM system transmission rate is slightly cheaper than PECO's, so a downward adjustment of .0128 cents/kWh must be made (while it is slightly higher for the residential rate class).

10. These reasons support the MAPSA contention that the PSE&G Stipulation's proposed shopping credits are inadequate to support the meaningful choice in the New Jersey market. If the PECO shopping credit is the base, the PSE&G shopping credit would have to be 5.51 cents/kWh to provide the same level of competition enjoyed by PECO consumers and the Philadelphia economy. As such, the Better Choice Settlement Proposal's proposed shopping credits of 5.4 cents/kWh are reasonable.

11. The PSE&G residential shopping credit, again adjusted for the above differences, would be 6.47 cents/kWh. As the Better Choice Settlement Proposal requests a residential shopping credit of 6.28 cents/kWh, I believe it is reasonable.

PECO Shopping Credits Updated for PSE&G in Year 2000:
(*add down from top to reach total*, e.g.: 4.91+(.0128)+.072+.05+.33+.165 = 5.51):

		System	Residential
Start with PECO Shop Credit		4.91	5.66
Add:	*Higher Costs in New Jersey*:		
	- Transmission:	(.0128)	.112
	- Taxes:	.072	.0784
	- LMP* Adjustment:	.05	.05
Add:	*Cost Increases Since PECO Settlement*:		
	- Energy (60% on-peak/40% off):	.33	.36**
	- Installed Capacity:	.165	.201
TOTAL: Parity-Adjusted Shopping Credits:		5.51	6.47

* LMP is an adjustment for a transmission congestion.

** Residential energy costs are higher due to higher on-peak consumption.

12. **The shopping credit embodied in the Better Choice Settlement Proposal will mean that the rate reductions experienced by Philadelphia-area consumers will be emulated in the PSE&G territory. However, PSE&G's proposed stipulation will result in shopping savings that are less like those experienced by PECO consumers, mainly due to the increases in costs in the forward energy market noted above. It is without dispute that many of the suppliers desiring to enter the PSE&G retail market will need to access the forward market at current levels, and that this fact will prevent the level of savings experienced in the PECO service territory from occuring in PSE&G territory unless the Board sees fit to adopt the shopping credit outlined in the Better Choice Settlement Proposal.**

Rate Levels after Month 48: The Better Choice Proposal vs. The PSE&G Stipulation

13. **The PSE&G proposed plan appears to imply that system average rate levels will rise to 1998 levels (approx. 10.447 cents/kWh) or thereabouts. While the exact system average rate levels in the PSE&G plan after month 48 is uncertain, the PSE&G plan seems to predict a rate increase of at least 10%, and as much as 14%, or more, depending on the level of deferrals to be collected from ratepayers and whether the securitizations savings are made permanent at that point in time.**

14. **The rate decreases in the PSE&G proposal will be implemented by making negative the MTC. PSE&G appears to eliminate the MTC after July 30, 2003, which would imply that rate levels will return back to 1998 levels or thereabouts. This fact is confirmed in page 2 of Attachment 12 of the PSE&G proposed stipulation, where it states: "A net MTC will appear on the customers bills as the sum of the unbundled charges, the NTC charge, less the Restructuring Reduction." Once this portion of the charge vanishes in month 49, rates would apparently jump by at least 10% (relative to the level of rates in effect in month 48) and return close to their 1998 levels.**

Further the PSE&G proposal does not indicate how the permanent rate decreases from securitization would continue to be reflected in its rates beyond month 48. PSE&G has valued the permanent rate decrease from securitization at approximately 3% minimally. It would appear that unless that portion of this rate decrease is reflected as a decrease of some permanent charge (e.g., distribution rates) customers will not continue to see those savings after the 48 month transition period is over.

16. **This fact must be contrasted with the Better Choice Settlement Proposal provision for sustained rate reductions beyond month 48. The first source of the Better Choice Settlement Proposal's rate reduction is from permanent cost reductions from securitization. The second level of rate reductions is due to the effect of a increasing kWh growth on a fixed annual securitization revenue requirement. The third rate source of sustained rate reductions is due to the flow-through to ratepayers of overcollections and expired amortizations and the excess balance in the depreciation reserve account. In the Better Choice Settlement Proposal, the savings from**

securitization would be reflected as a permanent rate reduction, while the rest of the reductions would be continued for an additional 24 months at a minimum. This fact, coupled with the fact that it provides PSE&G with an amount of stranded costs equal to what it claimed in its stipulation, establishes the superiority of the Better Choice Settlement Proposal for New Jersey.

<u>The Better Choice Plan is better for New Jersey than the PSE&G Stipulation Proposal</u>

17. I estimate that the Better Choice Settlement Proposal will provide, from guaranteed rate cuts alone, over $900 million in greater savings for New Jersey electricity consumers than PSE&G's stipulation proposal. Factoring in the benefits of shopping to New Jersey's consumers available in the Better Choice Settlement Proposal raises the net benefits of the Better Choice Settlement Proposal considerably higher. The Better Choice Settlement Proposal also reflects the valid public policy that a successful competitive retail electricity market must feature meaningful shopping opportunities for all customers. An example of legitimate shopping opportunities and savings is the PECO market. Based upon recently released data, approximately 1/3 of PECO's load is being provided by competitive suppliers (with PECO's affiliate, Exelon, being the largest provider). Almost 14% of residential load, 33% of commercial load, and 50% of industrial load is shopping in the PECO service territory. These numbers are even more impressive when one recalls that only 2/3 of industrial and commercial customers were eligible to shop for power in 1999.

PECO residential consumers have saved over $1,000,000 in just the first two months of electric competition in Pennsylvania. On an annualized basis, the savings for the 13.9% of PECO residential customers who are shopping is over $8,250,000. The savings for commercial and industrial classes in the first two months of shopping in the PECO market are significantly larger. While these levels of shopping savings may be prevented under the PSE&G plan, the Better Choice Settlement Proposal virtually assures that levels of shopping savings experienced in the PECO market will be experienced in the PSE&G market. In addition, the Better Choice Settlement Proposal delivers greater guaranteed rate cuts and allows PSE&G to recover stranded costs in excess of that identified by the Board's own Auditors under the Low Mitigation, base case market price scenario.

18. If the Better Choice Settlement Proposal were adopted, I estimate that residential customers should be able to see offers of savings from (August 1, 1999 rates) of at least 5- 7%. This is approximately the same level of savings that is currently being offered by suppliers to residential customers in the PECO service territory. I would note

that to make this type of offer suppliers will have to be very efficient in procuring power and keep their retail sales and marketing costs to a mininum.

19. **The problem presented by the PSE&G stipulation is that it will not reasonably assure the same level of savings that PECO customers have experienced, because of the aforementioned increases in costs related to forward market costs of energy and capacity, as well as specific differences between New Jersey and Pennsylvania.**

Better Choice Settlement Financial Calculations

20. **I have prepared Tables 1 through 4 of Attachment B to the Better Choice Proposal. I can answer questions as necessary regarding the preparation of these documents. Some disagreement exists between the parties regarding the amount of taxes associated with the securitized revenue stream. To be conservative, I have quantified taxes consistent with what appears to be the manner that PSE&G presented taxes on the securitization revenue stream. I reserve the right, however, to update Tables 1 through 4 as needed.**

21. **I estimate that PSE&G would realize a $54.636 million (NPV) contribution to stranded cost through the net difference between the implicit MTC and the "retail adder" retained from non-shopping customers. This is illustrated in Table 3 of Attachment B ("Implicit MTC Retail Adder Value Stream") of the Better Choice Settlement Proposal.**

I determined the retail adder by examining the costs of retail marketing including billing, electronic data exchange costs, bad debt collection, customer service, general overhead, regulatory expenses and profit. As can be seen, the retail adder is highest for residential consumers and falls according to customer classification. It is important to note that the retail adder is predominantly comprised of those costs that a supplier must incur to serve a customer, and there is very little profit in this figure. While one could disagree about the size of this retail adder, my calculation is far closer to reality than the adder that PSE&G used in their proposed stipulation. Moreover, if the actual retail adder that PSE&G will retain on customers that do not shop is slightly smaller, to the extent less customers shop, PSE&G may retain a larger net retail adder level.

PSE&G Mitigation Opportunities

22. The record in this case identifies numerous mitigation opportunities that PSE&G has had in the past and will have in the future.[1] The Better Choice Settlement Proposal focuses just on those mitigation opportunities identified in the Board's 1998 (Prepared by ICF Kaiser, et. al.) Audit report and ignores mitigation prior to 1999 and generally beyond 2005.

An example of these ignored mitigation opportunities beyond the transition period would be permanent cost savings from PSE&G performing at the average level of the top 50 U.S. nuclear plant total fuel and non-fuel production costs of 1.772 cents per kWh (see Energy Insights, Report of 9.23.98). Based on PSE&G cost forecasts in its restructuring case, the average fuel and non-fuel O&M costs for its 5 nuclear plants is 2.697 cents per kWh. The difference, 0.925 cents/kWh, translates to a $180 million annual mitigation opportunity or over $1.25 billion (today's dollars) savings to PSE&G for the remaining life of their nuclear plants. Apart from the reasonable mitigation expected of PSE&G in the Better Choice Settlement Proposal, PSE&G would stand to receive several hundred million more dollars as a result of increased productivity or cost reductions associated with increases in efficiency at its nuclear plants. As the record indicates, this also ignores several hundred million dollars in cost reductions not reflected in rates since PSE&G's last rate case.

[1] The Board's Audit Report appears to examine mitigation capability only until 2005 or thereabouts.

I hereby declare that the statements and calculations made in this affidavit are true and correct to the best of my personal knowledge and make this affidavit under penalty of perjury.

John S. Rohrbach

SUBSCRIBED AND SWORN TO before me this 28th day of March, 1999 in Harrisburg, Pennsylvania

Lori W. Walter

Notary Public

My Commission Expires on:

NOTARIAL SEAL
LORI W. WALTER, Notary Public
Harrisburg, Dauphin County
My Commission Expires Nov. 17, 2001

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Background:

'93 - '98 Pennsylvania Public Utility Commission — Harrisburg PA
Assistant to Commissioners Nora Mead Brownell (5.98 to 12.98) and John Hanger (8.93 to 5.98)

- Principal policy advisor for electricity market restructuring. Integral player in the development of and implementation of retail electric choice in Pennsylvania. Played a crucial role in the PECO Energy, PP&L, Allegheny Energy, Duquesne Light and GPU Energy restructuring cases, particularly in the areas of financial and quantitative analysis. Current efforts directed toward ensuring a vigorous competition in the PJM-PA and ECAR-PA wholesale and retail markets.
- Provided Affidavit in US District Court (Eastern District - PP&L Inc. v. John M. Quain, et. al., Civil No. 98-CV-5083) estimating damages to customers and the Commonwealth-at-large from an increase in installed capacity prices and from the stymieing of customer choice.
- Consultant to the Pennsylvania Department of Revenue on the tax impacts of electricity and natural gas restructuring. Numerous presentations to senior Pennsylvania state officials and electric and gas competition stakeholders. Provided testimony before the Virginia Senate on the impact of electric competition on Virginia tax revenues.
- Develop Commission policy regarding reform and operation of PJM Power Pool. Member: PJM Interconnection and PJM Market Monitoring Committee.
- Significant contributor to Commission Motions facilitating the functioning of competitive markets in telecommunications competition, alternative regulation and natural gas.
- Invited Presentations on stranded costs, electricity and natural gas restructuring.

'90 - '93 New Hampshire Office of Consumer Advocate — Concord NH
Economist

- Expert witness for NH residential consumers on rate of return, Seabrook decommission trust planning and telecommunications policy before the NH Public Utility Commission.
- Testimony ensured market-based rates-of-return and reduced intraLATA access rates. For nuclear decommission trust planning testimony, built econometric model of nuclear plant commercial life expectancy. Author of NH Supreme Court petition defending econometric model. Participated in other OCA litigation and organized conference on telecommunications.

'89 - '90 ECONorthwest – Analyst — Eugene OR
'85 - '89 New Jersey Board of Public Utilities – Research Economist — Newark NJ
'84 - '85 Vermont Department of Employment Security - Analyst — Montpelier VT

Education:

'82 - '84 Carnegie Mellon University, H. John Heinz School of Public Policy & Management — Pittsburgh PA
M.S. Public Management and Policy, May 1984. Teaching assistant - Macroeconomics.

'79 - '82 Rutgers University — New Brunswick NJ
B.A. Economics and Political Science, May 1982. Associate - Eagleton Institute of Politics

Both Publications - The Electricity Journal:

- Made in the Keystone State: The Pennsylvania Approach to Electric Competition - February 1999
- US Nuclear Decommissioning Trust Planning: Romancing a Millstone? - June 1995

ATTACHMENT E

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE ENERGY MASTER PLAN PHASE II PROCEEDING TO INVESTIGATE THE FUTURE OF THE ELECTRIC POWER INDUSTRY PUBLIC SERVICE ELECTRIC AND GAS COMPANY	))))))	BPU Docket Nos. EO97070461 EO97070462 EO97070463

AFFIDAVIT OF THOMAS BOUCHER

STATE OF VERMONT)
) ss. ___________
COUNTY OF CHITTENDEN)

I, Thomas Boucher, being first duly sworn, depose and say that I am providing this affidavit in support of the Better Choice Settlement filed by multiple parties in the above-captioned case.

1. I am Vice President of Energy Supply and Business Development for Green Mountain Energy Resources, a retail energy company serving over 100,000 residential customers with cleaner and renewable energy resources in deregulated electricity markets in Pennsylvania and California. As my title implies, I am responsible for acquiring power resources to serve our customers and for product development nationwide. Before joining Green Mountain Energy in 1997, I was responsible for energy supply and business strategy at Green Mountain Power Corporation for many years. I also served on the staff of the Vermont Public Service Board from 1981 to 1984. The purpose of this affidavit is to describe how I would expect the shopping credits proposed in the PSE&G settlement plan and the Better Choice Plan to impact on the New Jersey market, Green Mountain's participation in the market, and our ability to offer products featuring renewable resources to New Jersey customers at attractive prices.

2. First, for reasons described by John Rohrbach in his affidavit, the shopping credits proposed in the PSE&G settlement plan for residential customers are not adequate to support a vibrant competitive market for residential customers in New Jersey. If those credits are approved, we would expect to see a market in New Jersey that is less like the Pennsylvania market and more like the Massachusetts and California markets – in that there is inadequate allowance for the total cost of providing retail service to customers. In Massachusetts, there is virtually no competitive market activity associated with the residential market. In California, only a limited number of value-added "green" suppliers are offering choices to residential customers and only about 1% of those customers have

switched to competitive suppliers after a year of competition. In contrast, in Pennsylvania, where the shopping credits at the opening of the market provided suppliers with an opportunity to save customers money on their electric bills, many suppliers are active and over 300,000 residential customers have switched in the first few months of competition. Most of those switching customers are enjoying savings on their electric bills; many are choosing cleaner and renewable energy resources; and some are doing both. We would expect that a Pennsylvania-style market and the opportunities for residential customers that go along with that market would result from the level of shopping credits proposed in the Better Choice Plan.

3. It is likely (though not certain) that Green Mountain will participate in the New Jersey market even at the level of residential shopping credits proposed by PSE&G, if the many rules that the Board must adopt to implement restructuring support a competitive market and make the process of switching easy and inexpensive for customers and suppliers. This is possible because we offer customers very distinguishable, value-added products. There are, however, significant impacts on Green Mountain and its potential customers from the low level of shopping credits proposed by PSE&G. First, customers who care about the environment would have to pay a higher premium to switch to Green Mountain's products than they should have to, in comparison with the price they would pay if they stayed with Public Service. The higher the price premium for choosing renewable resources, of course, the less likely customers are to switch. In the PECO service territory Green Mountain has been able to offer its lowest price product to customers at a rate that is slightlybelow the shopping credit (although higher than many competitive offerings, of course). This has provided customers with an additional incentive to try cleaner and renewable energy choices.

4. Another impact of inadequate shopping credits on Green Mountain and New Jersey residential customers is equally important to consider. Green Mountain, and other value-added marketers alone, don't have the marketing budgets to make consumers aware of and excited about choice, even when state-sponsored consumer education (which is critical) is thrown into the mix. The level of awareness and customer propensity to switch are significantly enhanced when many suppliers are advertising and otherwise active in the market. This impact is very apparent to Green Mountain based on actual experiences in California versus Pennsylvania. On the day the market opened in Pennsylvania, Green Mountain had more customers in that market than we had after nine months of competition in California.

5. Finally, there are environmental and economic benefits to the state that should not be overlooked resulting from substantial market activity by renewables and cleaner resource suppliers and from customers switching to these resources. Consumer education provided by suppliers regarding the environmental consequences of electricity generation has been substantial, and over time is expected to build demand for these types of resources. Renewable and cleaner technologies are often modular in size, are candidates for distributed, versus central locations, and can support the local economy. Consumer demand for renewable resources in California and Pennsylvania has already resulted to

the development of new renewable resources, including new wind and solar facilities. We have already initiated the construction of large-scale solar electric facilities in Pennsylvania, and expect our wind development activity to result in new wind generator construction by next year. Moreover, the public education efforts of suppliers can be expected to impact on public support for environmental policy initiatives in the future. All of these benefits should encourage the Board to support a competitive electricity market and, as part of that support, shopping credits at a high enough level to cause a vibrant residential competitive market.

6. To achieve these benefits the Board should support a competitive electricity market and, as part of that support, shopping credits at a high enough level to encourage a vibrant, competitive residential market. The Better Choice Plan is clearly superior to PSE&G's settlement proposal in that regard.

Thomas Boucher

SUBSCRIBED AND SWORN to before me this 29th day of March, 1999 by Thomas Boucher.

My Commission Expires:
2-10-03

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE ENERGY MASTER PLAN PHASE II PROCEEDING TO INVESTIGATE THE FUTURE OF THE ELECTRIC POWER INDUSTRY PUBLIC SERVICE ELECTRIC AND GAS COMPANY	))))))	BPU Docket Nos. EO97070461 EO97070462 EO97070463

AFFIDAVIT OF RONALD J. MATLOCK

STATE OF TEXAS)
) ss. Houston
COUNTY OF _______)

Ronald J. Matlock, of full age, being duly sworn, according to law, deposes and says:

1. My name is Ronald J. Matlock. I am employed as a Market Analysis Manager for Shell Energy Services LLC ("Shell"), an affiliate of Shell Oil Company engaged in the marketing and provision of competitive gas and electric service, with an emphasis on residential and small commercial customers. The business address for Shell is 1221 Lamar Street, Suite 1000, Houston, Tx, 77010. Shell Energy Services LLC is a member of the Mid-Atlantic Power Supply Association, a party to this case.

2. My responsibilities at Shell include legislative and regulatory advocacy, and the necessary regulatory and economic analysis of gas and electric markets leading up to a go or no-go decision on market entry. Prior to working for Shell, I was employed as a Regulatory Analyst at a Chicago-based retail energy marketing firm where I had similar responsibilities. I also worked for nearly 8 years at the Texas Public Utility Commission as a Financial Analyst, Assistant Manager of Finance and Senior Economist. At the Commission, my responsibilities included testifying as an expert witness on a wide variety of economic and financial issues affecting electric utilities. I hold a B.S. in economics from Northern Illinois University and an M.B.A. in finance and accounting from the University of Texas.

3. After evaluation of the shopping credits for residential customers that are included in the proposed settlement by Public Service Electric & Gas (PSE&G), I have no level of confidence that Shell could economically attract and serve residential electric customers in light of the fact that suppliers must offer savings off the regulated rate in order to induce customers to switch. It has been Shell's experience that for the kind of product we offer, residential customers MUST be offered savings in order to motivate customers to take advantage of the lower prices offered in a competitive marketplace. The source for those savings is the shopping credit. A shopping credit such as that proposed by PSE&G in its stipulation proposal to the Board of Public Utilities would make it impossible to

attract and serve residential customers and would leave me no choice but to recommend that Shell not make the multi-million dollar investment required for a proper market launch into the PSE&G service territory.

Ronald J. Matlock

Ronald J. Matlock

SUBSCRIBED AND SWORN to before me this 26th day of March, 1999 by Ronald J. Matlock.

Carole Shalia

CAROLE SHALIA
MY COMMISSION EXPIRES
May 10, 2003

My Commission Expires:
5/10/03

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE ENERGY	)	
MASTER PLAN PHASE II PROCEEDING	)	BPU Docket Nos. EO97070461
TO INVESTIGATE THE FUTURE OF THE	)	EO97070462
ELECTRIC POWER INDUSTRY	)	EO97070463
PUBLIC SERVICE ELECTRIC & GAS	)	
COMPANY	)	

AFFIDAVIT OF JAMES P. MCCORMICK

STATE OF PENNSYLVANIA)
) ss. Pittsburgh
COUNTY OF ALLEGHENY)

James P. McCormick, of full age, being duly sworn, according to law, deposes and says:

1. I am Manager, Electricity Market Development, Mid-Atlantic Region with Strategic Energy, Limited, 2 Gateway Center, Pittsburgh, Pennsylvania, 15222. Strategic Energy, Ltd. ("SEL") has been providing electric retail access for customers since the beginning of the New Hampshire pilots. We are currently participating in Pennsylvania's retail choice program. SEL focuses its marketing efforts on the commercial and industrial customer classes.

2. My responsibilities at SEL include regulatory, legislative, and independent system operator advocacy to facilitate and assure development of robustly competitive electric marketplaces.

Prior to working with SEL, I was employed by the Pennsylvania Public Utility Commission. There, I advised the Commission on utility operations, organizational structure, and cost mitigation opportunities. As part of that endeavor, I worked to develop the Commission's "Report and Recommendations to the Governor and General Assembly on Electric Competition." Subsequently, I worked for the Commission within the stakeholder collaborative that developed Pennsylvania's retail choice legislation. After enactment of legislation, I worked within various Commission collaboratives to develop retail market implementation plans.

Before joining the Pennsylvania Commission, I was employed by PECO Energy. My experience at PECO included assignments within power generation, transmission, distribution, and customer service organizations. Several years of my experience involved organizational redesign to ready PECO for the emerging competitive retail electric marketplace. During that period, my focus was converting business units from cost centered to profit centered business units. My endeavors at PECO required cost analysis, budget development and management, project value analysis, benchmarking for business unit performance assessments, and business and operations process redesign.

I hold a Bachelors Degree in Mechanical Engineering from Villanova University, and attended Temple University Graduate School of Business Administration. I have also attended the Edison Electric Institute's Executive Management School and PECO Boiling Water Reactor Engineering School.

3. I have reviewed and analyzed the shopping credits that are proposed in the PSE&G Stipulation filed March 17, 1999 with the Board. Based on my analysis, I can conclude that the PSE&G Stipulation includes shopping credits that are insufficient to support the development of a robust competitive market for classes GLP, LPL - Secondary, LPL - Primary, and HTV - subtransmission.

4. SEL's experience in Pennsylvania markets is that nearly all industrial and large and medium commercial customers require suppliers to provide year forward power supply agreements. This means that customers require contracts that guarantee a fixed price for power for at least 1 year <u>and</u> which provide savings compared to the price they are charged by the utility. The cost of power now available in the forward energy market is significantly higher than it was last year when SEL was arranging for supply to begin to serve customers in Pennsylvania and would make it impossible to offer savings to these customers and still cover our costs. We see no indication that the present forward energy and capacity market offers are going to decrease to any significant degree on net in the next several years; indeed it is more likely that they will continue to increase.

5. Given customer requirements for long term commitments, the anticipated price levels in the forward power markets and our commitment to generate savings for customers, SEL expects to be unable to attract and serve GLP, LPL and HTV - subtransmission customers if the shopping credits remain at the low levels indicated in the PSE&G Stipulation.

James P. McCormick

James P. McCormick

SUBSCRIBED AND SWORN to before me this ~~26th~~ 29 day of March, 1999 by James P. McCormick.

Edith M Distel

My Commission Expires:
June '99

Notarial Seal
Edith M. Distel, Notary Public
Abington Twp., Montgomery County
My Commission Expires June 9, 1999
Member, Pennsylvania Association of Notaries

ATTACHMENT F

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE ENERGY) MASTER PLAN PHASE II PROCEEDING) TO INVESTIGATE THE FUTURE OF THE) ELECTRIC POWER INDUSTRY)	BPU Docket Nos. E097070461 E097070462 E097070463

AFFIDAVIT OF JAMES B. ROUSE

STATE OF NEW YORK)
) ss. Albany
COUNTY OF ALBANY)

James B. Rouse, being duly sworn, upon his oath, deposes and says:

1. I am associate director, energy policy/state affairs, for Praxair, Inc. an industrial gases manufacturer with facilities in 40 countries, including two production plants in New Jersey: Raritan Bay (Woodbridge Township) and Carneys Point, near the DuPont complex at Deepwater. Praxair produces oxygen, nitrogen, argon, carbon monoxide and other specialty gases for use by various business and industry in New Jersey, primarily the refining, petrochemical and pharmaceutical industries.

   As associate director, energy policy/state affairs, I represent Praxair in regulatory proceedings, legislative matters and in the public arena in all states where Praxair has major operations. Prior to assuming my duties at Praxair in 1992, I had similar responsibilities at Union Carbide Corporation from 1983 to 1988, where I served as senior manager, energy policy. From 1988 to 1992, I was regional director, government affairs, for Union Carbide, representing the company in the Northeast, including New Jersey.

   I have an undergraduate degree in government and foreign affairs from the University of Virginia; a master's degree from the Fletcher School, Tufts University; and a law degree from Cornell Law School. I was in private practice in New York City for two years, prior to joining Union Carbide's law department in 1977, where I served for six years before assuming my energy regulatory responsibilities.

2. Praxair is a member of the New Jersey Business Users (NJBUS), a party to the above-captioned case. I was a witness for NJBUS in the hearings that were conducted before the Office of Administrative Law. I am making this affidavit on behalf of the industrial customers that are members of the New Jersey Business Users.

3. I have had the opportunity to discuss with our attorney the relevant aspects of the partial Stipulation and Settlement entered into by Public Service and Gas Company (PSE&G) with a only a handful of other parties to the case, including certain "captive" parties, such as the Company's union.

4. It is my understanding that PSE&G is planning to transfer all of its owned generating assets, (a total of 9556 MW capacity) to an unregulated subsidiary (the "Genco") of PSEG, PSE&G's parent, at a value of only $1.768 billion. This implies a value of only about $185 per kW, a very low average value in the current market. As set out in an affidavit in this proceeding by Mr. Dirmeier on behalf of the Ratepayer Advocate, that valuation per kW appears to be extremely low, particularly for divestiture of fossil units in the Northeastern U.S. (See affidavit of Michael D. Dirmeier attached hereto.) An average per/kW value for recent sales in the Northeast should be imputed to PSE&G at least at the level set forth in Mr. Dirmeier's affidavit, if not higher. I have been advised that PSE&G's proposed Settlement would transfer the utility's owned generating assets without any right on the part of the Board or ratepayers to recalculate the value of the generating assets at a later time based on then current market conditions. Therefore, the amount of stranded costs to be recovered from ratepayers will not be reviewed and adjusted as contemplated by Section 13 g. of the Energy Competition Act.

5. Applying the low value per kW proposed by PSE&G to generating assets that are transferred out of the regulated utility increases the stranded costs that must be collected by the utility, to the detriment of ratepayers. PSE&G's book value for its owned generating plants is stated at approximately $ 5.1 billion, leaving stranded costs of more than $3.3 billion under PSE&G's valuation. It is my understanding that PSE&G has agreed to limit its collection of stranded costs to about $3.1 billion. Since $2.475 billion is being securitized under the PSE&G proposed Settlement, the utility must collect an additional $600 million from ratepayers in only 4 years. While NJBUS could, for the purpose of a compromise, agree that the utility be permitted to collect $2.475 billion through securitization (notwithstanding that this is a large amount of stranded costs to be collected through non-bypassable bond charges assessed on ratepayers over 15 years), the collection of an additional $600 million does not appear to be supportable based on current market conditions. (See Affidavit of Michael D. Dirmeier, attached hereto.) This is especially onerous if there is not going to be any later true-up based upon actual market values.

6. In addition, it is my understanding that the PSE&G proposed Stipulation provides for the utility to transfer other, non-production assets to the Genco along with the utility's owned generation assets, without any additional payment, and without a hearing to determine their value. These non-production assets include power and fuel contracts, real estate (including expansion and repowering opportunities on existing generating plant sites) and good will. Since the only book cost that PSE&G used to value the assets transferred to the Genco (after subtracting stranded costs) was production plant book costs, the value of these non-production assets has not been included. Thus, the value of the Genco is understated. More importantly, ratepayers are not being properly credited for the value that they have contributed to the Genco.

7. I want to relate recent experience elsewhere that bears on the administratively-determined valuation and recovery of stranded costs. In California, the legislation requires the major utilities to recover all their nuclear investment in a 4+ year transition period, and with a stranded cost recovery mechanism that makes shopping for energy almost prohibitive for potential sellers. The competition transition charge (CTC) is set to equal the residual difference between the customer's tariff rate and the cost of energy from the Power Exchange, plus transmission & distribution, plus societal benefits charges. Since the Power Exchange price is "energy only," very few if any marketers can afford to participate except at a loss; they can make money only by bidding into the Power Exchange itself.

In Ohio, recent proposals prior to introduction of legislation would allow some utilities to recover "transition revenues" in amounts as high as 250% of their generation net book value. This will allow those utilities to grossly over-recover their stranded costs. Although it is not known at the time of submission of this affidavit whether legislation will eventually incorporate such recovery, it is important for the BPU, for customers and for success of competition itself to avoid such a result. In establishing administratively-determined stranded costs, the Board must look to the marketplace where numerous actual transactions may be used to reach realistic valuations for generation assets. Otherwise, ratepayers/future customers will be saddled with inordinately large obligations, recovered during a multiyear transition period, without have received the benefit and protection of prudent regulatory determination.

James B. Rouse

James B. Rouse

SUBSCRIBED AND SWORN to before me this 29th day of March by James B. Rouse

Kimberly A. Schaffer

My commission expires:

~~KIMBERLY A. SCHAFFER Notary Public, State of New York Qualified in Schenectady County Commission Expires June 13,~~

KIMBERLY A. SCHAFFER
Notary Public, State of New York
No. 4934283
Qualified in Schenectady County
Commission Expires June 13, 2000