Verification of Deferred Balances And Prudence Review Phase 1: August 1999 – July 2002

Rockland Electric Company

Volume 1 – Verification and Analysis

Redacted Version

RECO Claimed "Trade Secret" Information
Has Been Redacted

PREPARED FOR

THE NEW JERSEY BOARD OF PUBLIC UTILITIES

BY

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Exhibits showing verified monthly balances for RECO's deferrals and calculations of interest on corrected monthly deferred balances are presented in Volume 2 of this report.

I. Executive Summary

Chapter 1 – Executive Summary

A. Background

Rockland Electric Company ("RECO" or "Company") is a wholly owned subsidiary of Orange & Rockland ("O&R"), which in turn is a wholly owned subsidiary of Consolidated Edison Company ("Con Edison").

Prior to the Con Edison merger, O&R was an exempt holding company and the operating company serving a territory in New York. The other regulated utility companies besides O&R are RECO and Pike County Light & Power Company ("Pike"). RECO and Pike exist because of the state boundaries. RECO is in New Jersey. Pike is in Pennsylvania. RECO and Pike have no employees. All services are provided by O&R.

O&R, RECO and Pike function as an integrated system. The system was part of the New York Power Pool ("NYPP"). O&R operates the system as one integrated system. The NY Power Pool became the New York Independent System Operator ("NY ISO") and, as a result, O&R became affiliated with the NY ISO.

O&R generation and NYPP economic purchases provided for the power supply needs of the entire O&R system. Through a FERC-approved Power Supply Agreement ("PSA"), the costs associated with the O&R system power supply were allocated to RECO.

O&R sold all of its generation assets to affiliates of Southern Company. All of the generation assets formerly owned by O&R are located in NY. O&R received approval from all three states (NY, NJ and PA) for the sale of the O&R generation assets. O&R's belief was that NY had sole jurisdiction over the sale of the plants, but O&R nevertheless sought and received approval not only from NY, but also from NJ and PA.

O&R entered into buy-back contracts for the power from the units it sold to Southern. As those contracts were phased out, O&R power purchases were conducted through the NY ISO.

Within the O&R System, there are three operating divisions:
1) Eastern, consisting of O&R and RECO, which services Rockland County, NY, and the northern part of Bergen County, NJ.
2) Central, consisting of O&R and RECO, which services portions of Sussex and Passaic Counties, NJ (RECO), and Orange and Rockland Counties, NY (O&R).
3) Western, consisting of O&R, RECO and Pike, which services part of Pike County in PA (Pike), Sullivan County, NY (O&R), and Sussex County, NJ (RECO).

Retail access for the entire O&R region was made available in 1999. Retail access for the NY and PA portions occurred in May 1999 and for the NJ (RECO) portion in August 1999.

As part of the NJ electric utility industry restructuring, and in accordance with the Electric Discount and Energy Competition Act (N.J.S.A. 48:3-49 et seq., "EDECA"), RECO's rates were unbundled, reduced and frozen for a four-year transition period, from August 1, 1999 through July 31, 2003. During this period, RECO accumulated the differences between the revenues it received for Basic Generation Service ("BGS"), Energy Cost Adjustment ("ECA"), and Societal Benefits Charge ("SBC") and related costs in deferral accounts. RECO's August 30, 2002 filing in Exhibits FPM-2, FPM-3 and FPM-4 presented monthly balances for BGS, ECA and SBC deferrals respectively. The information presented on these RECO exhibits contained actual amounts for August 1999 through July 2002, and projected amounts for August 2002 through July 2003.

The NJ Board of Public Utilities ("Board" or "BPU") hired Larkin & Associates, PLLC ("L&A") to review and verify RECO's BGS, ECA and SBC deferrals. The review is being conducted in two phases. Phase I covers the three-year period August 1999 through July 2002. Phase 2 will cover the period August 2002 through July 2003. The review conducted by L&A also included a review of RECO's interest calculation, which was presented on RECO Exhibit FPM-8 and verification of RECO's deferred restructuring proceeding costs, which were presented by the Company on RECO Exhibit FPM-9.

In addition to verification of the amounts recorded by RECO, this project also includes a review and assessment of the prudence of RECO's power procurement and cost mitigation efforts. This prudence review has been conducted by Synapse Energy Economics, Inc. ("Synapse"), functioning as a subcontractor to L&A on this project.

B. Organization of Report

This report is organized into two volumes. Volume 1 describes the review of each area, and presents the analysis and conclusions. Volume 2 presents exhibits relating to the verification of RECO's deferred balances and the calculation of interest. The exhibits presented in Volume 2 are referenced in Volume 1.

Volume 1 is organized into the following four major sections:
I. Executive Summary (Chapter 1)
II. Verification of Deferred Balances (Chapters 2-5)
III. Interest Calculation (Chapter 6); and
IV. Prudence Evaluation (Chapters 7-11).

Within Section II, Verification of Deferred Balances, the presentation is organized into the following chapters:
2. Verification of BGS Deferrals
3. Verification of ECA Deferrals

4. Verification of SBC Deferrals
5. Verification of 1997 Restructuring Proceeding Cost Deferrals

Section III, Interest Calculation, consists of Chapter 6. The interest calculation uses the BGS, ECA, SBC and deferred restructuring proceeding balances from Chapters 2 through 5, respectively. This chapter also addresses the "net-of-tax" issue and related matters. A calculation of interest incorporating the exclusion of amounts found to be imprudent as the Synapse analysis, is also presented in Chapter 6.

Section IV, Prudence Evaluation, presents the analysis of Synapse Energy Economics, Inc. concerning the prudence of RECO's power procurement and cost mitigation efforts. This section is organized into the following chapters to address each of the important questions posed in the Governor's Task Force Report, including the specific questions from pages 19-20 of that report:

7. Bilateral Power Contracts and Spot Market Purchases
This chapter addresses the following issues from the Task Force Report:
- Did RECO make reasonable decisions about how much spot market power to purchase and how much power to purchase at fixed prices under longer-term contracts?
- Did RECO enter into power contracts at the right time and for the right duration?
- Why didn't RECO lock into a three-year contract guaranteed at BGS price levels as PSE&G did?

8. Transfer of RECO's Eastern Division to PJM
This chapter addresses the analysis and timing of the transfer and answers the following question posed in the Task Force Report:
- Why didn't RECO join the PJM system earlier?

9. Cost Mitigation Efforts – Hedging Program
Chapter 9 addresses the amount and reasonableness of the cost of hedges that Con Edison incurred on behalf of, and charged to, RECO.

10. Cost Mitigation Efforts – Renegotiation of NUG Contracts
Chapter 10 discusses RECO's contracts with Non-Utility Generators (NUGs) and any efforts made to renegotiate above-market NUG contracts.

11. Quantification of Imprudence Disallowances
This chapter presents the quantification of the disallowances related to the Synapse findings of imprudence.

C. Review Periods

This report is for Phase 1. The review period covered in this report is August 1, 1999 through July 31, 2002. This represents Years 1 through 3 of the transition period for RECO in conjunction with the NJ electric utility industry restructuring. Review of

RECO's deferred balances for Year 4, which covers the period August 1, 2002 through July 31, 2003, will be addressed in Phase 2.

D. Review Standards and Procedures

Larkin & Associates' review process ensures that work is factually based, that the observations and comments formed are supported by relevant data, that professional judgment, where applied, is differentiated from analytical results, and that the results of the review are traceable to specific efforts.

During this project the L&A conducted 17 formal interviews with Company personnel. A summary for each interview was prepared and provided to the Company. Each summary was then reviewed, edited if necessary, signed by the interviewee(s) and returned to L&A.

During the project, the Larkin/Synapse team also issued five sets of Audit Data Requests (ADRs), RECO-ADR-L-1 through RECO-ADR-L-112. The responses to these ADRs were reviewed, as were RECO's responses to data requests issued by other parties, such as the Ratepayer Advocate, where the topics of those requests impacted deferred balance verification or prudence evaluation issues.

In addition to formal interviews and ADRs, deferred balance verification and reconciliation issues were covered in numerous informal discussions with Con Edison accounting personnel, with accompanying exchange of information. The project team appreciates the assistance of Con Edison and O&R personnel in resolving deferred balance reconciliation issues.

The parties involved in L&A's quality assurance process for this review were L&A and Synapse consultants. Our approach to project management and preparing this review are essential components of L&A's quality assurance process. No pertinent information was omitted from this report because it was deemed privileged or confidential.[1]

A final draft of this report was provided to the Board Staff on December 23, 2002, and to RECO on December 24, 2002. Comments concerning factual accuracy and confidential information were received from RECO on December 31, 2002, and are incorporated into the final report.

E. Summary of Findings and Conclusions

As shown in Exhibits 2.1, 3.1 and 4.1, provided in Volume 2 of this report, the verified amounts of RECO's deferred BGS, ECA and SBC balances at July 31, 2002, including the impacts of corrections that were identified during the verification process are $79.479

[1] Note: Certain RECO-designated "confidential" information concerning hedging strategies has been omitted in the redacted version of this report.

million, $9.666 million (credit balance), and $759,000, respectively. These Exhibits also show the amounts for each month during the Phase 1 review period of August 1999 through July 2002.

Exhibit 5.1, in Volume 2 of this report, summarizes the verified amounts for RECO's restructuring proceeding cost deferrals of $887,000, after reflecting the removal of amounts that RECO has indicated it will remove, correction of the amortization amount through July 31, 2003, and the removal of $205,115 of charges related to nine invoices that were requested for verification purposes, that RECO failed to provide. Deferred verified restructuring proceeding costs through July 31, 2002, are $930,000. The fourth year of amortization of $43,512 reduces this deferred amount to $887,000 by July 31, 2003.

Exhibit 6.1 presents a calculation of interest if done on a "net-of-tax" basis for the period August 1, 1999 through July 31, 2002 on the corrected monthly deferred balances. This calculation results in interest of $6.523 million on the corrected RECO deferred balances through July 31, 2002.

Exhibit 6.2 presents an interest calculation for the period August 1, 1999 through July 31, 2002, which incorporates the impact of removing the amounts of RECO's BGS cost that Synapse found resulted from imprudence. These calculations result in interest of $3.910 million for the period August 1, 1999 through July 31, 2002 on the deferred balances, after exclusion of costs related to imprudence. The Synapse analysis and findings related to imprudence are explained in Chapters 7 through 11 of this report.

As described in Chapters 7 and 11, the Synapse analysis concluded that during the period August 1, 1999 through July 31, 2002, RECO incurred imprudent costs of $26.805 million. Synapse determined that RECO was imprudent in failing to negotiate multi-year parting contracts for the power from its divested generating assets. This failure meant that RECO's customers were almost completely exposed to the newly opened New York wholesale capacity and energy markets after the Transitional Power Sales Agreement ("TPSA") expired for energy in April 2000 and for capacity in October 2000.

As described in detail in Chapters 8 through 10:

- Concerning the timing of the transfer to PJM, as described in Chapter 8, Synapse found no imprudence by the Company in arranging for the PJM Transfer. The transfer itself was undoubtedly a good idea. Based on a detailed review of the timeline for making the transfer, Synapse concludes that the timing was not unreasonable. Synapse does not believe the Company was imprudent in not joining the PJM system earlier.
- Concerning mitigation of cost through hedging activities, as described in Chapter 9, Synapse found that decisions regarding hedging and contracting during the August 1, 1999 through July 31, 2002 were not imprudent. In terms of the language of the Task Force Report, and based on the information reviewed, Synapse concludes that RECO did make "reasonable decisions about purchasing power in the deregulated market."

- Concerning NUG cost mitigation, as described in Chapter 10, Synapse concludes that the Company's failure to attempt to renegotiate or buyout its small amount of NUG contracts was not imprudent, given the relatively small amount of cost and power provided by NUG contracts, and explanations provided by the Company concerning why efforts were not made to renegotiate NUG contracts.

Chapter 11 presents Synapse's quantification of imprudent costs, which total $26.805 million.

II. Verification of Deferred Balances

Chapter 2 - Verification of BGS Deferrals

Overview
In RECO Exhibit FPM-2, the Company reports the following amounts of Basic Generation Service Costs, Revenues and Deferred Fuel Amortization for the three-year period August 1999 through July 2002:

Rockland Electric Company Basic Generation Service Summary of All Rate Years ($000's)	Actual 12 Months Ended 7/31/00	Actual 12 Months Ended 7/31/01	Actual 12 Months Ended 7/31/02	Totals Through 7/31/02
Period Costs and Revenues				
BGS Auction / PJM Transfer	$ -	$ -	$ 1,143	$ 1,143
Purchased Power Costs - NYISO	$ 73,976	$ 97,445	$ 49,436	$ 220,857
Purchased Power Costs - PJM	$ -	$ -	$ 26,077	$ 26,077
Eastern Load Pocket Costs	$ 158	$ 720	$ 830	$ 1,708
Hedging Costs	$ -	$ 6,932	$ 4,662	$ 11,594
Total BGS Costs	**$ 74,134**	**$ 105,097**	**$ 82,148**	**$ 261,379**
BGS Revenue	**$ (55,317)**	**$ (60,944)**	**$ (65,185)**	**$ (181,446)**
Deferred Fuel Amortization	**$ (331)**	**$ (122)**	**$ (125)**	**$ (578)**
Deferred Balances				
Beginning Balance	**$ 1,278**	$ 19,764	$ 63,795	$ 1,278
Ending Balance	**$ 19,764**	**$ 63,795**	**$ 80,633**	**$ 80,633**

Verification Process
Verification efforts related to RECO's deferred BGS costs included:

- Verifying amounts on the O&R MSC[2] workpapers to invoices.
- Reconciling amounts on RECO Exhibit FPM-2 to the O&R MSC Workpapers.
- Where invoices were from Con Edison to O&R, obtaining and reviewing power cost charges to Con Edison from the third-party suppliers.
- Testing calculations on the O&R MSC workpapers.
- Interviews and discussions with Con Edison personnel concerning power costs charged to RECO
- Review of hedging cost invoices and allocations of such cost to RECO.
- Obtaining and reviewing monthly amounts from RECO's Detailed Trial Balance for the period August 1999 through July 2002.
- Summarizing the monthly BGS deferrals from the Detailed Trial Balance on a workpaper and comparing each month's amount with the amount shown on RECO Exhibit FPM-2.

[2] The term "MSC" is derived from "Market Supply Charge" which is a term used in New York.

- Investigating variances in each month that were noted. This was done by presenting summaries of variances to Con Edison accounting personnel, and obtaining explanations and further reconciliation detail from them.
- Reviewing a reconciliation of deferred monthly BGS balances on RECO Exhibit FPM-2 with amounts in the RECO general ledger prepared by Con Edison accounting personnel. This was provided to us on November 6, 2002 as the result of questioning by us as to why amounts on FPM-2 did not agree with the RECO general ledger. The Company-prepared reconciliation included additional supporting documentation, such as explanations and journal entries.
- Reviewing the corrections to RECO Exhibit FPM-2 provided by the Company. On November 7, 2002, RECO provided updated versions of Exhibit FPM-2 (and FPM-3 and FPM-9), that reflected correction of certain errors that were known to the Company at that time.
- Conducting further testing and review of the BGS reconciliation and the Company's response to RECO-ADR-L-95.
- Pursuing additional power cost reconciliation and verification issues with Con Edison accounting personnel. This resulted in an agreement (communicated to us on December 19, 2002, via fax and email) by the Company to correct O&R power costs charged to RECO for the period July 1999 through January 2001. These corrections are summarized on Exhibit 2.2. Also see discussion below, under the headings, "Verification of Purchased Power Costs" and "Corrections to Amounts on RECO Exhibit FPM-2."
- Pursuing BGS revenue reconciliation issues with Con Edison accounting personnel. Corrections to BGS revenue in a number of months within the August 1999 through July 2002 period for reconciliation variances were resolved with Con Edison accounting personnel through a series of information exchanges and discussions. The corrections to resolve the BGS revenue differences are summarized on Exhibit 2.3. Also see discussion below, under the headings, "Verification of BGS Revenue" and "Corrections to Amounts on RECO Exhibit FPM-2."

Additional details concerning verification efforts related to specific costs affecting RECO's deferred BGS balance, and verification of monthly BGS revenues (net of NJ sales tax) are described below.

Verification of Purchased Power Costs

To verify RECO's purchased power costs from the NYISO and PJM, we obtained and reviewed the Company's calculations contained in the MSC workpapers. From the MSC workpapers, we traced the amounts that are presented on RECO Exhibit FPM-2. From January through July 2002, variances with the purchased power costs were noted and investigated. Included in the corrections provided by the Company in its response to RECO-ADR-L-95, were adjustments that resolved several variances.

We verified purchased power costs to invoices by summarizing the monthly power purchases from the Detailed Trial Balance for Purchased Power onto two workpapers.

The first workpaper compared each month's amounts with the amounts shown on the MSC workpapers for the period August 1999 through December 2000. Significant variances were noted and investigated in each month for the period August 1999 through December 2000. In response to inquiries, RECO provided a reconciliation of purchased power costs where the Company agreed to adjust its cost recovery calculation. These adjustments include, at the O&R system wide level, power costs of approximately $1.725 million for the period July 1999 through March 2000 and approximately $196,000 for the period April 2000 through January 2001. As a result of these adjustments, and by using the O&R system Provider of Last Resort (POLR) energy ratios, the correction of power costs for the period July 1999 through January 2001 reduces RECO's power cost by approximately $612,000. A summary of the corrections to RECO's power cost for this period is presented on Exhibit 2.2, in Volume 2 of this report.

We prepared a second workpaper that summarized the monthly power purchases from the Detailed Trial Balance for Purchased Power for the period January 2001 through July 2002, and compared each month's amount with the amounts shown on the RECO's supporting documentation and Monthly Reconciliation Packages. Where issues arose concerning certain amounts during the verification process, these were discussed with Company personnel and were satisfactorily resolved.

There were a number of invoices billed to O&R from Con Edison for power and/or hedging purchases made by Con Edison on O&R's behalf. We obtained and reviewed invoices showing power cost charges to Con Edison from third party suppliers.

Verification of Load Pocket Costs

RECO's Eastern Division exists in a load pocket. At times, due to transmission constraints, the Lovett Plant that O&R sold to Southern Energy affiliates must be run to provide energy to RECO's Eastern Division. O&R has an Eastern Load Pocket Agreement with Mirant[3] to ensure the availability of the Lovett generating station which is located in the Eastern Load Pocket. Under this agreement, an annual payment is made to Mirant to ensure the availability of Lovett, subject to minimum availability criteria. The Agreement also requires that additional payments be made to Mirant in those instances when the system's operators require Lovett to operate to ensure load pocket reliability, but the NY ISO has not dispatched Lovett to a sufficient level to support the load pocket, due to economic considerations.[4] To verify RECO's Eastern Load Pocket Costs, we obtained and reviewed the Company's Substation Output Summaries and other supporting documentation provided in response to our inquiries regarding the BGS reconciliation. A question arose with respect to an amount of $92,000 included on Exhibit FPM-2 in the month of December 2001. L&A verified that this amount was removed from deferred BGS costs in one of the corrections made to RECO deferred BGS costs in the Company's response to RECO-ADR-L-95.

In addition, on the reconciling workpapers covering the period January 2001 through July 2002, a few questions arose concerning the timing and amounts of Load Pocket

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[3] Formerly Southern Energy affiliates.
[4] See testimony of Joseph Holtman, p. 16.

payments. These were discussed with Con Edison accounting personnel. Due to the difficulty Con Edison has with verifying power usage related to generation for load pocket issues, amounts for load pocket power purchases are often accrued over several months, and are then paid in a lump sum upon verification. Based on the follow through discussions and documentation provided, we are satisfied that the load pocket costs reflected on RECO Exhibit FPM-2, as corrected in the response to RECO-ADR-L-95 are supported by documentation and invoices.

Verification of Deferred Fuel Amortization

RECO Exhibit FPM-2 shows approximately $578,000 of Deferred Fuel Amortization for the period August 1, 1999 through July 31, 2002. The monthly amounts on Exhibit FPM-2 were compared with the amounts listed in RECO's response to RECO-ADR-L-20. For the month of August 1999, the Deferred Fuel Amortization amount on RECO Exhibit FPM-2 includes $212,000 collected through the Levelized Energy Adjustment Clause ("LEAC") for NUG buyout cost recovery that is reflected in August due to the proration of billings. Based on the verification conducted, we are satisfied that the amounts for Deferred Fuel Amortization amount on RECO Exhibit FPM-2, which include the application of LEAC cost recovery in August 1999, are appropriate.

Verification of Costs for the PJM Transfer and BGS Year 4 Auction

RECO Exhibit FPM-2 included $1.143 million of cost through July 31, 2002 related to the transfer of RECO's Eastern Division to PJM and the BGS Year 4 auction. Verification efforts for this cost included:

- Obtaining an itemization of the charges (See RECO's response to RAR-MTC-18, Attachment A).
- Obtaining a copy of the RECO work order(s) used to accumulated such costs.
- Obtaining invoices for the costs, and tracing the amounts RECO accumulated in the applicable work orders to the invoices[5].
- Obtaining an electronic listing from RECO of all charges recorded in work orders 40-8818 and 46-8848 and using Excel pivot tables to verify the Company's accumulation of charges by type.
- Discussing the cost accumulation with Con Edison accounting personnel.
- Recalculating the $325,429 of labor and overhead charges listed on RAR-MTC-18, Attachment A to test its accuracy.
- Accumulating charges into work order 40-8848, RECO Meter Installations for Transfer to PJM, from the Detailed Trial Balance for 12/31/01 and 9/30/02, and reconciling these to the amount shown on RECO Exhibit FPM-2.
- Recalculating the amount of charges recorded in each month and comparing these with the amounts listed on RECO Exhibit FPM-2, page 4 of 5.

Based on the verification conducted, we are satisfied that the costs related to the transfer of RECO's Eastern Division to PJM and the BGS Year 4 auction on RECO Exhibit FPM-2 through July 31, 2002, are adequately supported by invoices and related accounting documentation.

[5] Invoices were provided in response to RECO-ADR-L-97.

Verification of Hedging Cost
RECO Exhibit FPM-2 included $11.594 million of hedging cost through July 31, 2002. Approximately 14.4% of RECO's total accumulated BGS deferral through July 31, 2002 of $80.633 million[6] was caused by the net cost of hedging transactions. All energy price hedging contracts for O&R and RECO were obtained on their behalf by the Con Edison Supply Department.[7]

Types of hedging contracts purchased by the Con Edison Supply Department on behalf of O&R and RECO included:

- A "collar" which provides a ceiling and floor price. If within the band, the power purchase is settled at the NY ISO price and no other payments are made. If the price is less than the floor, Con Ed pays the hedge provider the difference between the NY ISO price and the floor price. If the price exceeds the ceiling, Con Ed receives the difference between the NY ISO price and the ceiling from the hedge provider.[8]
- A "swap" or "contract for differences" which is a fixed price financial hedge. As an example, for May 2001, if the ISO day ahead (DA) price is greater than the fixed price, Enron would pay Con Ed. If the ISO price is less than the fixed price, Con Ed would pay Enron. In this instance, Con Ed paid Enron, and there was a $2,508 charge to O&R. This was allocated 97.5% to RECO, and 2.5% to Pike.[9]
- A "participating" hedge is one that allows Con Ed to participate in price declines. A participating swap for the summer of 2001 was allocated 100% to O&R NY. If the NY ISO price exceeds the fixed swap price, the hedge provider (counter party) pays Con Ed the full difference. If the NY ISO price is less than $70/mwh, for example, Con Ed pays the counter party ½ of the difference. The effect is to lock in the maximum price at $70/mwh, but to allow Con Ed to participate in 50% of the difference if the NY ISO price turns out to be below $70/mwh.[10]
- A dual-trigger "temperature option" hedge. The dual trigger was (1) price above $100/MWH and (2) temperature in White Plains, NY, above 90 degrees. If both parts of the dual trigger occurred, price would be capped at $100/MWH.[11]
- "5 x 16" energy strips, which are "physical hedges" (i.e., actual contracts to buy electricity) that provide for the purchase of energy at fixed prices for a specified period, Monday through Friday, hours 7 am through 11 pm.[12]

Verification efforts for hedging costs charged to RECO included:

- Verifying the amounts for hedging cost on RECO Exhibit FPM-2 to the monthly O&R MSC workpapers.

[6] RECO Exhibit FPM-2, page 1 of 5.
[7] Interview #2, Joseph Holtman, 10/29/02, p.11.
[8] See, e.g., Interview #2, page 12, and invoices the Company supplied in response to RECO-ADR-L-26.
[9] Interview #2, page 12, hedging invoices, and hedging cost allocation sheets.
[10] Interview #2, page 12, and hedging invoices.
[11] Interview #2, page 14 and hedging invoices.
[12] Interview #2, pp.12-13, and general knowledge.

- Interviewing Con Edison Supply Department personnel to understand the specific hedging transactions entered into on behalf of O&R and RECO.
- Verifying amounts for hedging costs shown on the monthly MSC workpapers to invoices.
- Obtaining explanations from Con Edison for differences noted.
- Checking the allocation of hedging cost to RECO by reviewing and selectively recalculating allocations prepared by the Con Edison Supply Department
- Reviewing billings from Con Edison to O&R and RECO for hedging costs.
- Following through with Con Edison to obtain missing information.

Based on the verification conducted, we conclude that the cost of hedging contracts entered into by the Con Edison Supply Department on behalf of RECO is adequately documented with invoices, and the allocations of hedging cost to RECO were based on rational relationships between the cost incurred and the purpose of the hedging transaction.

Verification of BGS Revenue

To verify monthly BGS revenue, we obtained copies of RECO's monthly revenue reports, compiled the monthly BGS revenues from such reports, removed the NJ sales tax (by dividing the monthly revenue amounts by 1.06) and compared the result with the monthly BGS revenues listed on RECO Exhibit FPM-2. We noted a number of months where the revenue amounts derived in this manner did not agree with the amounts shown on RECO Exhibit FPM-2. Differences in monthly revenues (after removal of NJ sales tax) resulted from a number of causes, including instances where RECO did not remove the sales tax, where RECO removed the sales tax by multiplying the monthly revenue by 0.94 (rather than dividing the revenue by 1.06), or where corrections to revenues were made in other months, but the corrected monthly revenue amounts were not necessarily reflected on RECO Exhibit FPM-2.

As of 12/18/02 there remained a number of differences between the results of our efforts to verify RECO's monthly BGS revenues and the amounts shown on RECO Exhibit FPM-2. L&A engaged in further discussions and exchanges of information with Con Edison accounting personnel to resolve these concerns. Adjustments to some of the monthly BGS revenue amounts on RECO Exhibit FPM-2 are necessary. Exhibit 2.3 shows the monthly adjustments to BGS revenue we have calculated based on our verification efforts. From additional discussions and exchange of proposed calculations between L&A and Con Edison accounting personnel on 12/19-20/02, we understand that the Company agrees that RECO recorded BGS, ECA and SBC revenue (after removal of NJ Sales and Use Tax ["SUT"]) in an inconsistent manner from month to month during the period August 1999 through July 2002, and that the corrections shown on Exhibit 2.3 are appropriate.

Corrections to Amounts on RECO Exhibit FPM-2

On 11/7/02, in response to RECO-ADR-L-95, RECO provided updated versions of Exhibits FPM-2 (and FPM-3 and FPM-9), reflecting corrections of certain errors known to the Company at that time. The corrections to RECO's power costs covered in the response to RECO-ADR-L-95 are reflected on Exhibit 2.1 in Volume 2 of this report, which summarizes RECO's BGS deferrals for each month of the period August 1999 through July 2002, as corrected for items revealed during the verification process.

On 12/19/02, in response to inquiries following through on a reconciliation of purchased power costs recorded in Accounts 555 and 565 with amounts used in the Company's cost recovery calculations, a number of corrections to purchased power costs were confirmed. These include an adjustment to O&R system level power costs of approximately $1.725 million for the period July 1999 through March 2000 and approximately $196,000 for the period April 2000 through January 2001. Using the O&R system Provider of Last Resort (POLR) energy ratios, the impact on RECO of these adjustments is a reduction of power cost of approximately $612,000 for the period July 1999 through January 2001. These corrections to RECO's power costs are summarized on Exhibit 2.2.

As noted above, corrections to the amounts of monthly BGS revenue are summarized on Exhibit 2.3.

Summary

Exhibit 2.1, in Volume 2 of this report, shows the monthly verified amounts for RECO's BGS deferrals, after reflecting the corrections discovered by L&A and Con Edison accounting personnel during the verification process. As shown on Exhibit 3.1, page 3, the corrected deferred BGS balance at July 31, 2002, is $79.479 million.

Issue With Respect to Allocation of PJM Transfer Costs and PJM Energy Costs

During the course of our efforts to verify RECO's deferred BGS costs, an issue has come to our attention concerning (1) the allocation of costs to transfer RECO's Eastern Division into PJM, which are allocated 100% to New Jersey, and (2) the allocation of PJM energy between RECO's New Jersey customers and O&R's New York Customers, which for the period March through July, 2002, is summarized in the following table:

Allocation of PJM Energy Between NY and NJ			
Month	O&R (NY)	RECO (NJ)	Total
Mar 2002	13.3697%	86.6303%	100.00%
Apr 2002	13.7807%	86.2193%	100.00%
May 2002	11.5331%	88.4669%	100.00%
Jun 2002	7.8388%	92.1612%	100.00%
July 2002	6.2493%	93.7507%	100.00%

Source: O&R MSC Workpapers, PJM Control Area, Allocation of Net Purchased Energy

As shown in the above table, a not insignificant portion of the PJM energy is being allocated to O&R's New York customers. It thus appears that O&R customers in New York are receiving the benefit of energy purchased in the PJM control area, while 100% of the cost of accomplishing the transfer to PJM is being allocated to New Jersey customers.[13] We have not calculated and are not recommending an adjustment pertaining to this apparent inconsistency in the allocation of PJM transfer cost (all to NJ) and the allocation of PJM energy cost (which has ranged from 6.25% to 13.78% to NY). However, we do point out the issue, so other parties participating in the proceedings concerning RECO's deferred balances are aware of it.

[13]As set forth in RECO's response to RECO-ADR-L-112(d), the Company's position is that the allocation of PJM energy to O&R's New York load is immaterial, unintentional, and temporary, as described in RECO's response to RECO-ADR-L-102, which states that:

"Energy purchased from PJM is intended for RECO's customers in PJM's control area. However, there are some unintended loop flows on the RECO/O&R distribution system causing PJM energy to flow into New York. RECO is working with PJM and NYISO to develop an accounting mechanism that will result in all energy flowing into New York on the stateline crossings being considered NYISO load. This will establish the state line as the border between the NYISO and PJM loads. In the interim period, a portion of the cost associated with energy purchases in the PJM control area is allocated to New York. The allocation is based on metered energy at the New Jersey-New York distribution system crossings." In July 2002, the New York allocation was 6.2% and varies monthly.

Chapter 3 - Verification of ECA Deferrals

Overview

The monthly ECA deferrals are the result of the difference between (1) monthly ECA revenues and (2) monthly ECA costs. The monthly ECA costs are the above-market cost of power purchases from Non-Utility Generators (NUGs). During the period August 1999 through July 2002, RECO reported on its Exhibit FPM-3, amounts of $7.072 million of above-market NUG costs and $16.658 million of ECA revenue, resulting in a net <u>credit</u> of $9.586 million for its deferred ECA balance at July 31, 2002.

RECO's parent company, Orange and Rockland, has five NUG contracts[14]. The cost of power purchased under the O&R contracts with the NUGs is allocated pursuant to the O&R Power Supply Agreement ("PSA"). The O&R PSA describes how power purchased by O&R is allocated among the O&R companies, which include Orange & Rockland (New York), Pike County Light and Power Company (Pennsylvania) and RECO (New Jersey). Prior to the transfer of RECO's Eastern Division to PJM, the above-market cost of all O&R NUGs was determined by comparing the cost of power purchased from the NUGs with the average cost of NY ISO power for the month. After the transfer of RECO's Eastern Division to PJM, two calculations are made: one for the NUGs located in the NY ISO, and another calculation for the one NUG that is now located within the PJM boundary.

Verification Approach

Our verification of RECO's monthly ECA deferrals included the following:

- We obtained monthly amounts from RECO's Detailed Trial Balance for the period August 1999 through July 2002.
- We summarized the monthly ECA deferrals from the Detailed Trial Balance on a workpaper and compared each month's amount with the amount shown on RECO Exhibit FPM-3.
- Variances in each month were noted and investigated. Where appropriate, additional documentation was obtained from RECO and reviewed.
- The monthly calculations of above-market NUG costs were obtained and reviewed. (See additional discussion below.)
- Monthly ECA revenues on Exhibit FPM-3 were reconciled with amounts obtained from RECO's monthly revenue reports. (See additional discussion below.)
- Differences in monthly revenue amounts were discussed with Con Edison accounting personnel, and corrections were prepared to address the ECA revenue amounts that were applied by RECO on its Exhibit FPM-3 in certain months. (See additional discussion below.)

[14] See, e.g., RECO response to RAR-MTC-45.

Verification of Above-Market NUG Costs

To verify RECO's above-market NUG costs, we obtained and reviewed the Company's calculations.[15] The review of above-market NUG costs, which are allocated to ECA, was conducted as part of our overall review of O&R NUG costs allocated to RECO. NUG costs were verified to invoices, and the determination of above-market and at-market costs as calculated by the Company in its MSC workpapers were reviewed.

Effective March 1, 2002, RECO's Eastern Division became part of the PJM ISO. Prior to the effective date of this transfer, all of O&R, including RECO's Eastern Division had been in the NY ISO. This change also effectively moved the border between PJM and the NY ISO to the NJ-NY state line, whereas prior to the conversion, the NY ISO extended into the portion of NJ served by RECO's Eastern Division. The conversion to PJM also affected how the above-market costs for one of the NUGs supplying power to O&R is calculated. Before the transfer of RECO's Eastern Division to PJM, all of the NUGs supplying power to O&R were located within the NY ISO area, and the NY ISO prices were utilized to determine the at-market and above-market costs. After RECO joined PJM, one of the O&R NUGs (Crossroads), which is in Mahwah, NJ, is now located in the PJM area. For this NUG that is now located in the PJM area, the Company uses PJM prices (rather than NY ISO prices) to determine the at-market and above-market costs.

An average monthly price for each control area (NY ISO and PJM) is used to determine the at-market NUG costs. The at-market NUG cost is then deducted from the total net NUG cost for each control area, resulting in an amount of above-market NUG cost for each control area. The above-market NUG costs for each control area are added together and the total is allocated to O&R (NY), RECO (NJ) and Pike (PA) using system energy ratios.[16]

O&R buys power from the NUGs around the clock, except for outages. It is possible that for some hours during the month, the NUG power cost would be lower than the NY ISO or PJM cost. On average, however, the NUG cost typically exceeds the market cost in each month. The O&R method of using the average monthly power cost has not been reviewed or approved in a Board order at that level of detail.[17]

We reviewed the Company's calculations of at-market and above-market NUG costs and the allocation to RECO for the period August 1999 through July 2002 and found them to be reasonable.

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[15] The at-market and above-market NUG cost calculations are part of the monthly MSC workpapers which show the allocation of purchased power cost between O&R (NY), RECO (NJ) and Pike (PA).

[16] See, e.g., Interview #5, Rich Kane, George Lerose and Bill Atzl, 10/20/02, p.4, and O&R MSC workpapers.

[17] Interview #5, p.4.

Verification of ECA Revenue
To verify monthly ECA revenue, we obtained copies of RECO's monthly revenue reports, compiled the monthly ECA revenues from such reports, removed the NJ sales tax (by dividing the monthly revenue amounts by 1.06) and compared the result with the monthly ECA revenues listed on RECO Exhibit FPM-3. We noted a number of months where the revenue amounts derived in this manner did not agree with the amounts shown on RECO Exhibit FPM-3. Differences in monthly revenues (after removal of NJ sales tax) resulted from a number of causes, including instances where RECO did not remove the sales tax, where RECO removed the sales tax by multiplying the monthly revenue by 0.94 (rather than dividing the revenue by 1.06), or where corrections to revenues were made in other months, but the corrected monthly revenue amounts were not necessarily reflected on RECO Exhibit FPM-3.

As of 12/18/02 there remained a number of differences between the results of our efforts to verify RECO's monthly ECA revenues and the amounts shown on RECO Exhibit FPM-3. We have been engaged in discussions and have exchanged information with Con Edison accounting personnel to resolve these concerns. Adjustments to some of the monthly ECA revenue amounts on RECO Exhibit FPM-3 are necessary. Exhibit 3.2 shows the monthly adjustments to ECA revenue we have calculated based on our verification efforts. From additional discussions and exchange of proposed calculations between L&A and Con Edison accounting personnel on 12/19-20/02, we understand that the Company agrees that RECO recorded BGS, ECA and SBC revenue (excluding NJ SUT) in an inconsistent manner from month to month during the period August 1999 through July 2002, and that the corrections shown on Exhibit 3.2 are appropriate.

Summary
Exhibit 3.1, in Volume 2 of this report, shows the monthly verified amounts for RECO's ECA deferrals, after reflecting the corrections discovered by L&A and Con Edison accounting personnel during the verification process. As shown on Exhibit 3.1, page 3, the corrected deferred ECA balance at July 31, 2002, is a credit balance of $9.666 million.

Chapter 4 - Verification of SBC Deferrals

Overview

As shown on RECO Exhibit FPM-4, for the period August 1999 through July 2002, the Company incurred costs for the Societal Benefit Charge (SBC) in three categories:

- Energy Efficiency & Renewables ("EE&R"),
- Consumer Education Program ("CEP"), and
- Universal Service Fund ("USF").

Monthly SBC revenues are compared with monthly SBC costs, and the difference is recorded as an adjustment to RECO's Deferred SBC Balance.

Verification of EE&R Costs

RECO Exhibit FPM-4 includes $5.749 million of cost for EE&R programs for the period August 1999 through July 2002. RECO accumulates EE&R program costs in individual work orders to keep track of the costs it is incurring for specific programs. Charges are cleared on a monthly basis from the work orders and posted to the deferral account.

Our verification of RECO's deferred EE&R costs consisted of multiple steps, including the following:

- Obtaining a listing of work orders and costs for each work order.
- Tracing O&R's and RECO's invoices to the individual work orders.
- Tracing costs in specific EE&R work orders, which are designated by specific numbers, to the RECO Detail Trial Balance.
- Tracing the amounts from the Detail Trial Balance that cleared the costs recorded in the work orders by transferring such costs into the deferral account. This was accomplished by tying the amounts clearing the work orders to the General Ledger. In some of the work orders, due to accruals carrying over from month to month, the amounts that cleared the work orders did not always agree with the Accounts Payable distributions.
- Discussing reconciling issues with Con Edison accounting personnel. As a result of such discussions, we were able to determine by journal entry number, which amounts represented Accounts Payable ("A/P") distributions, and which amounts represented accruals. The netting of these amounts agreed with the amounts clearing the work orders and postings to the General Ledger.
- Comparing the amounts on RECO Exhibit FPM-4 to the General Ledger. This revealed a number of significant variances. On a monthly basis, we listed the totals of the EE&R accounts from the General Ledger, the amounts from Exhibit FPM-4, and the associated variances. These differences were resolved as the result of further analysis and additional discussions with Con Edison accounting personnel.

- Analyzing the response to RAR-MTC-26, which provided a breakout of the EE&R costs from RECO Exhibit FPM-4. Through a series of computations, we were able to trace most of the amounts from RAR-MTC-26 to the General Ledger. The remaining issues corresponded with the variances noted above, that were resolved through further analysis and additional discussions with Con Edison accounting personnel.
- Resolving reconciling differences through a number of informal data requests and additional analysis by L&A and discussions with Con Edison accounting personnel who provided explanations and supporting documentation that enabled us to satisfactorily resolve the outstanding issues.

We conclude that RECO's EE&R costs for the period August 1999 through July 2002 are adequately supported by accounting records and invoices. Our verification efforts for EE&R costs for this period did not result in any recommended corrections to the Company's amounts shown on RECO Exhibit FPM-4.

Verification of CEP Costs

The CEP is part of the original NJ regulatory proceeding that called for educating NJ customers (both electric and gas) that they have opportunities to select other suppliers of the commodity. Customers were also educated and informed that their electric service bills would look different. There would be a separate charge for the commodity. Customers were informed that they could select an alternative supplier or stay with the utility. RECO's NJ CEP included two components:

1) a statewide integrated program to educate customers about the changes and the choices they would have; and

2) a localized RECO-specific program to supplement the statewide program and address specifics that applied to the RECO service area.

For the statewide program, all of the NJ utilities utilized the services of Winning Strategies, which was the only vendor for CEP costs for the NJ statewide program. During 1999, RECO worked with other vendors besides Winning Strategies for RECO's own localized efforts for customer education. RECO paid approximately $18,000 to other vendors in conjunction with the start up of its localized CEP program shortly before or after August 1999, the official start date of deregulation; however, RECO charged this to expense during 1999 (as opposed to including such cost in the deferred account, as its statewide CEP costs were).[18]

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[18] RECO did not include approximately $18,000 of local CEP cost on its filed RECO Exhibit FPM-4; RECO did not update or correct FPM-4 in response to RECO-ADR-L-95; and during a 10/31/02 interview (Interview #6, Jim Lois and Cecille Drier, 10/31/02, p.4), Company representatives told us that RECO expensed the approximately $18,000 of cost for its local CEP during 1999, as opposed to including it in the deferred SBC account. Because this cost was not included in RECO's deferred SBC balance on RECO Exhibit FPM-4, or included in a correction to that exhibit, verification of the amounts expensed by RECO in 1999 that were <u>not</u> included by RECO in its deferred balance on Exhibit FPM-4 was not conducted. During the 10/31/02 interview, a Company representative indicated that, if such costs for localized customer education efforts, which were previously expensed by RECO in 1999, were to be approved for future recovery by the Board, RECO would set up a deferral related to such approved recovery. On 1/2/03 RECO presented us with a reconciliation of its position to the amounts it had previously shown on RECO

All of the costs for CEP, totaling approximately $417,000 through July 31, 2002, on RECO Exhibit FPM-4 are costs associated with Winning Strategies in conjunction with the NJ statewide CEP program.

RECO is allocated 2% of the NJ statewide CEP program cost that is allocated to electric utilities in the state. The total NJ statewide CEP program cost was allocated between electric and gas. RECO was charged for 2% of the cost for the statewide CEP program that was allocated to NJ electric utilities.

The NJ statewide CEP program covered the following periods:

Year 1	April 1, 1999	through	March 31, 2000
Year 2	April 1, 2000	through	March 31, 2001
Year 3	April 1, 2001	through	March 31, 2002

The Company explained that the NJ statewide CEP program ended March 31, 2002. There were some residual bills received from Winning Strategies after that date.[19]

To verify RECO's CEP costs, the monthly amounts listed on Exhibit FPM-4 were traced to RECO's Detailed Trial Balance, and invoices for such costs were reviewed. Where questions concerning certain amounts arose during the verification process, these were discussed with Company personnel and were satisfactorily resolved.

We conclude that RECO's CEP costs for the period August 1999 through July 2002 are adequately supported by accounting records and invoices. Our verification efforts for CEP costs for this period did not result in any recommended corrections to the Company's amounts shown on RECO Exhibit FPM-4.

Verification of USF

The USF is a low income program. All NJ utilities were ordered to implement an interim USF for the 2001/2002 heating season. A Board order concerning this was issued in Docket No. EX00020091 in April 2002. There was an additional Board order issued November 21, 2001, setting up the program. The final order requires that any electric heating and LIHEAP eligible customer receives a $200 bill credit. This is a statewide program for all NJ electric utilities. There were only 28 customers in the RECO service territory which received USF payments from the interim program. RECO incurred administrative costs in 2002, including payroll cost and travel expense to attend meetings with the BPU Staff that was related to both the interim and permanent USF programs. The Company's response to S-RUSF-4 shows the $9,000 expense.[20]

FPM-4 that we were able to verify, which suggests that RECO will now be attempting to add $18,855 of local CEP costs incurred in 1999 to its deferred SBC balance.

[19] See, e.g., Interview #6, page 7, and CEP cost supporting documentation.
[20] See, e.g., Interview #4, Kevin Jones and Rich Kane, 10/30/02, page 3.

RECO Exhibit FPM-4 shows approximately $9,000 of Universal Service Fund cost through July 31, 2002. The monthly amounts on Exhibit FPM-4, page 4, for USF were compared with the amounts listed in RECO's response to data request S-RUSF-4. No differences were noted.

SBC Revenue Verification

To verify monthly SBC revenue, we obtained copies of RECO's monthly revenue reports, compiled the monthly SBC revenues from such reports, removed the NJ sales tax (by dividing the monthly revenue amounts by 1.06) and compared the result with the monthly SBC revenues listed on RECO Exhibit FPM-4. We noted a number of months where the revenue amounts derived in this manner did not agree with the amounts shown on RECO Exhibit FPM-4. Differences in monthly revenues (after removal of NJ sales tax) resulted from a number of causes, including instances where RECO did not remove the sales tax, where RECO removed the sales tax by multiplying the monthly revenue by 0.94 (rather than dividing the revenue by 1.06), or where corrections to revenues were made in other months, but the corrected monthly revenue amounts were not necessarily reflected on RECO Exhibit FPM-4.

As of 12/18/02 there remained a number of differences between the results of our efforts to verify RECO's monthly SBC revenues and the amounts shown on RECO Exhibit FPM-4. However, we were able to resolve these concerns by continuing discussions and exchanges of information with Con Edison accounting personnel. Adjustments to some of the SBC revenue amounts on RECO Exhibit FPM-4 are necessary due to incorrect/non removal of sales tax, and other errors discovered during the verification process. Exhibit 4.2 shows the monthly adjustments to SBC revenue L&A calculated based on our verification efforts. From additional discussions and exchange of proposed calculations between L&A and Con Edison accounting personnel on 12/19-20/02, we understand that the Company agrees that RECO recorded BGS, ECA and SBC revenue (net of NJ sales tax) in an inconsistent manner from month to month during the period August 1999 through July 2002, and that the corrections shown on Exhibit 4.2 are appropriate corrections to RECO's monthly SBC revenues.

Summary

Exhibit 4.1, in Volume 2 of this report, shows the monthly verified amounts for RECO's SBC deferrals, after reflecting the corrections discovered by L&A and Con Edison accounting personnel during the verification process. As shown on Exhibit 4.1, page 3, the corrected deferred SBC balance for RECO at July 31, 2002, is $759,000. (As noted above, this amount does not include $18,855 for local CEP costs expensed by RECO in 1999 which were not included in the deferred SBC balance on RECO Exhibit FPM-4.)

Chapter 5 - Verification of 1997 Restructuring Proceeding Cost Deferrals

Overview

RECO Exhibit FPM-9 presented the Company's identification of costs for its 1997 restructuring proceeding. RECO's presentation shows $1.741 million of cost, less $241,000 amortization through July 31, 2003.

Verification Process

The verification process applied to test RECO's costs for the 1997 restructuring proceeding listed on RECO Exhibit FPM-9 included the following:

- An itemized listing of charges that comprised the $1.741 million was obtained and reviewed.
- A copy of RECO work order 46-8505 that was established to accumulated costs related to RECO's 1997 restructuring filing was obtained and reviewed.
- Amounts were traced from the itemized listing to RECO's Detailed Trial Balance.
- Amounts were traced from the itemized listing to invoices that were requested.
- Issues concerning missing invoices and amounts included within the $1.741 million were discussed with the Con Edison accounting personnel, but were not totally resolved.
- The amortization amount on RECO Exhibit FPM-9 was compared with amounts recorded by the Company and with the annual amortization amount authorized by the Board.

Difficulties Experienced in Verifying Amounts to Invoices

Concerning the restructuring proceeding costs listed on Exhibit FPM-9, RAR-MTC-34 (dated September 27, 2002) had requested full and complete copies of any and all invoices from all outside vendors relating to the charges claimed in Exhibit FPM-9. RECO's response to RAR-MTC-34 stated: "The requested documents are extremely voluminous. Any party that wishes to make arrangements to inspect and/or copy this material should contact RECO counsel John Carley at 212-460-2097 to arrange for inspection." L&A had contacted Mr. Carley and Mr. Marino via phone and email prior to our first on site visit (which commenced October 28, 2002) to make sure that such material would be available for on site review.

When it still had not been made available by Wednesday, November 6, another call was placed to Mr. Carley, attempting to review the requested restructuring invoices. We also note that similar information was requested in RECO-ADR-L-25 (served on October 14, 2002). L&A obtained a listing from the company and a few invoices, and provided the Company with a list of restructuring invoices for changes on RECO Exhibit FPM-9 totaling $1,694,668 that were selected for review.

Apparently, the invoices requested in RAR-MTC-34 and RECO-ADR-L 25 had not previously been assembled by the Company for review by anyone. Con Edison accounting personnel indicated that a request to "archives" would be made for the material in the hopes that it could be made available for on site review commencing November 18, the date of another scheduled L&A on site review. It was also noted that

RECO Exhibit FPM-9 included costs for a 1993 management audit, which the Company has agreed do not relate to the 1997 restructuring proceeding and should therefore be removed from that cost.

During the week of November 18-22, some additional restructuring proceeding invoices were provided by Con Edison. As of December 19, 2002, however, a number of invoices requested by L&A to verify RECO's 1997 restructuring proceeding costs have not yet been provided by the Company. Of the $1,694,668 total amount of restructuring proceeding cost covered by the invoices that were requested for review, the Company provided invoices totaling $1,015,424, or about 60% of that amount, but failed to provide requested invoices for $679,244, or about 40% of that amount. A letter dated 12/12/02 emailed by Con Edison to L&A agreed to remove a portion of the cost covered by requested invoices that the Company failed to provide from the restructuring cost amount on RECO Exhibit FPM-9. After accounting for the items that RECO has agreed to remove, requested invoices for nine items totaling $205,115 have not been received as of December 19, 2002, and it appears that RECO has no intention of providing the requested invoices related to those charges.

RECO's 12/12/02 letter/email summarizes the Company's position concerning the invoices that, despite repeated requests, have not been provided, as follows: "Notwithstanding our inability to locate those bills, the costs were legitimately incurred in the Restructuring Proceeding and should be recovered in accordance with RECO's Restructuring Plan as approved in the BPU's Summary and Final Orders."

In our view, RECO's failure to supply requested invoices for the nine items totaling $205,115 by December 19, 2002 is unacceptable, especially given the fact that these were requested in late September in RAR-MTC-34 and again in early October in RECO-ADR-L 25, and that persistent efforts were made by L&A through December 12, 2002, to obtain the invoices for such charges, including repeated requests and reminders to the Company to provide those invoices. Consequently, we have removed this amount.

Corrections to Amounts on FPM-9

On 11/7/02, in response to RECO-ADR-L-95, RECO provided updated versions of Exhibits FPM-9 (and FPM-2 and FPM-3), reflecting corrections of certain errors known to the Company at that time. The corrections listed on RECO-ADR-L-95, Attachment C, were for the removal of approximately $352,000 of cost for a 1993 management audit, which RECO had inadvertently included in FPM-9, and a correction to the amortization amount to reflect the Board approved annual amortization of $43,512.

On 12/12/02, a "Letter on Restructuring Invoices" was received from Con Edison, which has helped to resolve some additional concerns relating to specific items included within the RECO amount of $1.741 million on Exhibit FPM-9. In particular, RECO agreed to remove $96,355 of consulting fees and $26,347 of legal fees from the 1997 restructuring proceeding costs it had listed on Exhibit FPM-9, because these were determined to be unrelated to the restructuring proceeding.

As noted above, on Exhibit 5.1, L&A has also removed $205,115 of charges related to nine invoices that were requested for verification purposes, that RECO failed to provide.

Summary

Exhibit 5.1, in Volume 2 of this report, summarizes the verified amounts for RECO's restructuring proceeding cost deferrals of $887,000, after reflecting the removal of amounts that RECO has indicated it will remove, correction of the amortization amount through July 31, 2003, and the removal of $205,115 of charges related to nine invoices that were requested for verification purposes, that RECO failed to provide.

III. INTEREST CALCULATION

Chapter 6 - Interest Calculation

This chapter addresses the calculation of interest on RECO's deferred costs. This chapter also addresses the "net-of-tax" issue and related matters.

RECO's Interest Calculation
RECO's calculation of interest was presented in Exhibit FPM-8 of its August 30, 2002 filing in BPU Docket No. ER02080614. We note the following with respect to RECO's calculation of interest presented on its Exhibit FPM-8:

- It uses monthly balances for BGS, ECA, SBC and restructuring proceeding cost deferrals from Exhibits FPM-2, FPM-3, FPM-4 and FPM-9, which have in some months been subject to correction and/or revision, as described above in Chapters 2 through 5 of this report.
- It does not apply a net-of-tax calculation to the deferred balances for the period August 1, 1999 through July 31, 2002. This is based on an interpretation by RECO that the requirement for a net-of-tax calculation does not begin until July 22, 2002, which was the date of the Board's Final Order in the RECO restructuring proceeding, Docket Nos. EO97070464, EO97070465 and EO97070466.
- When it commenced application of a net-of-tax calculation on Exhibit FPM-8, page 4, for the projected period August 2002 through July 2003, a net-of-tax factor of 65% was used, which reflects <u>only</u> federal income tax, and does not reflect NJ Corporate Business tax. ("CBT") This is contrary to a Board finding that the net-of-tax calculation should reflect the use of a combined tax rate of 40.85%.
- It reflects an annual compounding of interest. The cumulative interest for Year 1 (the 12-month period August 1999 through July 2000) as shown on Exhibit FPM-8, page 1, is added to the total deferred balance upon which interest is computed for Year 2 (August 2000 through July 2001), as shown on Exhibit FPM-8, page 2, etc.
- For Years 1 through 3 (the 36-month period August 1999 through July 2002) the calculation reflects the application of different interest rates on monthly deferred balances up to $5 million, and balances over $5 million, as described on page 22 of RECO witness Frank Marino's August 30, 2002 testimony.
- For the 36-month period August 1999 through July 2002, RECO's calculation results in cumulative interest of $11.876 million.

The "Net-of-Tax" Issue
RECO has taken the position that the Board's intent is to have interest calculated on a "net-of-tax" balance only starting with July 22, 2002, which was the date of the Board's

Final Order.[21] RECO based its interpretation on what it thinks is a reference by the Board to "gross" deferred balances in the Summary Order.[22] On October 16, 2002, the Board issued its Order on RECO's Motion for Reconsideration.[23] In that Order, the Board found that the net-of-tax methodology is the appropriate ratemaking treatment for RECO's deferred balances, and that interest should be computed on a net-of-tax basis.

The Board's October 16, 2002 Order (at page 2) stated that: "Contrary to RECO's assertion in its Motion, the Summary Order did not modify the RECO Plan to require that interest was to be applied to the gross (as opposed to the net of tax) amount of the Deferred Balance. Rather, the Board, by its silence on the issue, left intact the net of tax provision in RECO's proposed Plan as well as the deferred cost elements to be included in the Deferred Balance."

At page 4 of that Order, the Board stated that:

> "… the appropriateness of the net of tax treatment reflects the fact that even though no revenue was received for the deferred costs during the Transition Period …, the deferred costs did provide a tax benefit, namely a reduction to RECO's federal and state income taxes of approximately 41% [footnote 2] of the amount of the deferred costs. This reduction accordingly reduced the amount needed to finance the deferred balance during the Transition Period. While the tax benefit must in turn be paid back to the Internal Revenue Service and the State Treasury during the period over which the deferred costs are subsequently recovered, because of its size, it nevertheless yields a substantial reduction in the interest that would otherwise be payable, i.e., the interest that would be payable on the full deferred balance absent the tax reduction. The Board FINDS that it is reasonable and appropriate that this timing benefit flow to the benefit of ratepayers."

In footnote 2, the Board stated that: "The exact percentage is 40.85%, the effective composite federal corporate income tax rate (35%) and New Jersey CBT rate (9%), with the state component deductible for federal."

On November 4, 2002, RECO filed with the Board a Motion for Reconsideration in part of the Board's October 16, 2002 Order on Motion for Reconsideration and/or Clarification. Through the date of this writing, we are not aware of a Board Order being issued in response to this RECO November 4, 2002 Motion.[24]

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[21] See, e.g., Testimony of RECO witness Frank Marino, p.23, L.3-5; also see Interview #1, Frank Marino, 10/29/02, and RECO's Motion for Reconsideration filed on August 12, 2002.

[22] See Interview #1, pages 5-6, which reference page 4 of the Summary Order and RECO's August 12, 2002 Motion. Also see the Company's response to RECO-ADR-L-59 for a statement of the Company's position.

[23] Board's Order on RECO's Motion for Reconsideration and/or Clarification in BPU Docket Nos. EO97070464, EO97070465 and EO97070466.

[24] On December 30, 2002, we received, via email from RECO, a letter dated December 17, 2002, from RECO to the BPU, stating that: "RECO withdraws its November 4, 2002 Motion for Reconsideration in part of the Board's October 16, 2002 Order on Motions for Reconsideration and/or Clarification."

RECO's response to RECO-ADR-L-57 confirms that all of the deferred costs in Mr. Marino's Exhibits FPM-2 (BGS), FPM-3 (ECA), FPM-4 (SBC), and FPM-9 (restructuring proceeding costs) are deductible for income tax purposes. Also, to the extent that those costs are deferred for book purposes, a deferred federal income tax provision is provided.

The Company's response to RECO-ADR-L-58 shows the deferred federal and NJ state income tax amounts that were provided by RECO on the Company's deferred balances. To compute the deferred taxes for each period on each component of the deferred balances, the Company used the combined federal income tax and NJ CBT rate of 40.85%.

During on-site verification, we reviewed RECO's NJ CBT returns for 1999, 2000 and 2001 and its Schedule M, which shows a reconciliation of book and taxable income for federal income tax purposes, and conducted an interview with Con Edison Tax Department personnel knowledgeable about RECO's state and federal tax returns and RECO's deferred income tax calculations.[25] 1998 was the first year for NJ CBT. For CBT, the entire difference between book and tax (other than permanent differences) is multiplied by the 9% NJ CBT rate to derive RECO's deferred tax balance for NJ taxes.[26]

Conclusion: The use of net-of-tax balances for RECO's interest calculation appears to be consistent with the guidance provided in the Board's October 16, 2002 Order on RECO's Motion for Reconsideration, and with the recording of deferred federal income tax and NJ CBT related to the deferred balances on RECO's books.

Revised Interest Calculation

The Interest Calculation shown in Volume 2 of this report on Exhibit 6.1 attempts to provide for the standardization of the interest calculation in accordance with guidance provided by Staff. It corrects RECO's calculation regarding the use of an appropriate net-of-tax factor, as noted above. To make this calculation, we used the BGS, ECA, SBC and deferred restructuring proceeding costs from Chapters 2 through 5, respectively.

We reflected deferred taxes at 40.85%. We did this by multiplying the monthly Deferred Balance subtotals by 59.15%.[27]

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[25] Interview #3, Sal Zaccagnino, Con Edison Tax Department, 10/30/02.

[26] RECO deferred taxes are derived on the book-tax timing differences in this manner, i.e., on a fully normalized basis, despite the existence of some NJ CBT tax losses for 2000 and 2001 which are being carried forward and cannot be applied until 2004. The 2002 Instructions for Corporation Business Tax Return, instruction for Line 35, describes the change to the NJ CBT that now prohibits taking a deduction in years 2002 and 2003 for a Net Operating Loss (NOL) carryover from a prior year. A question was raised as to whether RECO had realized a NJ CBT benefit from the full amounts of its Deferred Balances, in view of the existence of NOL carryovers. As explained by Mr. Zaccagnino during his interview, the use of full normalization for NJ CBT on the amounts of RECO's deferred balances reflects that amounts of CBT tax losses are being carried forward, but the Company expects to use them to reduce CBT taxes in the future.

[27] 1 – combined tax rate of 40.85% = 59.15% for the net-of-tax balances.

We used the same interest rates that were reflected by RECO on Mr. Marino's Exhibit FPM-8. These rates were verified to the applicable Board Order or other supporting documentation.

We have also reflected the annual compounding of interest, similar to RECO's calculation on Mr. Marino's Exhibit FPM-8. Annual compounding of interest is also consistent with Staff proposed guidance to standardize the interest calculation. The tax deductibility of interest is reflected in the calculation by including the interest in the deferred balance to which the "net-of-tax" factor is applied.

As shown on Exhibit 6.1, this calculation results in interest of $6.523 million for the period August 1, 1999 through July 31, 2002 on the deferred balances.

Interest Calculation Incorporating Impact of Imprudence Disallowance

Exhibit 6.2 presents an interest calculation for the period August 1, 1999 through July 31, 2002, which incorporates the impact of removing the amounts of RECO's BGS cost that Synapse found resulted from imprudence. These calculations result in interest of $3.910 million for the period August 1, 1999 through July 31, 2002 on the deferred balances, after exclusion of costs related to imprudence. The Synapse analysis and findings are explained in the following chapters of this report.

IV. PRUDENCE EVALUATION

This Section presents the results of Synapse Energy Economic, Inc.’s investigation of the prudence of RECO’s power procurement and cost mitigation efforts. This Section is organized into the following Chapters and addresses important questions posed in the Governor’s Deferred Balances Task Force Report:

7. Bilateral Power Contracts and Spot Market Purchases

8. Transfer of RECO’s Eastern Division to PJM

9. Cost Mitigation Efforts – Hedging Program

10. Cost Mitigation Efforts – Renegotiation of NUG Contracts

11. Quantification of Imprudence

Chapter 7 - Bilateral Power Contracts and Spot Market Purchases

This Chapter addresses the following issues from the Task Force Report:

- Did RECO make reasonable decisions about how much spot market power to purchase and how much power to purchase at fixed prices under longer-term contracts?
- Did RECO enter into power contracts at the right time and for the right duration?
- Why didn't RECO lock into a three-year contract guaranteed at BGS price levels as PSE&G did?

Synapse's conclusions on these questions are:

1. RECO only entered into a short-term parting contract with the purchaser of its generating assets. RECO was imprudent in failing to negotiate multi-year parting contracts for the power from its divested generating assets. This failure meant that RECO's customers were almost completely exposed to the newly opened New York wholesale capacity and energy markets after the Transitional Power Sales Agreement ("TPSA") expired for energy in April 2000 and for capacity in October 2000.

2. PSE&G was able to lock into a three year contract guaranteed at BGS price levels because it was able to divest its generating assets to an affiliate with which it then contracted for BGS power. O&R did not have the same opportunity as it was under pressure from the New York State Public Service Commission ("NYPSC") to divest its generating assets to an unaffiliated party. However, as noted above, O&R could have taken advantage of the opportunity to enter into a medium term contract with the purchaser of its generating assets.

RECO is a wholly-owned subsidiary of Orange & Rockland Utilities (O&R), and supplies the New Jersey portion of O&R's service area. O&R was one of the first utilities to divest its generation assets under the New York Public Service Commission's electricity restructuring program. All of the generation assets are in New York State, as is most of O&R's load. The assets were sold to Southern Company's deregulated affiliate which became the Mirant Corporation ("Mirant") under an agreement finalized on November 24, 1998 and effective June 30, 1999. As of the latter date O&R, including RECO, needed new power supply arrangements.

The interim step taken by O&R was to enter into a Transitional Power Sales Agreement (TPSA) and an Incremental Energy Sales Agreement (IESA) with Mirant ("the parting contracts"). The parting contracts were, however, of relatively short duration, the longer-term strategy being for O&R to rely upon the new power market being established by the

New York Independent System Operator (NYISO). The IESA expired when the NYISO market commenced operations on November 18, 1999, and the TPSA was designed to phase out by October 31, 2000.

RECO is located within a load pocket, O&R's Eastern Load Pocket, which necessitates the operation of the Lovett Generating Station. At the time it divested its generating assets, O&R entered into a call option agreement with Mirant to ensure the availability of power for reliability purposes from Lovett at reasonable cost.

RECO has argued that its decision to enter into the short-term TPSA and IESA parting contracts with the buyer of its divested generating assets was reasonable. We disagree. We believe that, given the almost total uncertainty about the new competitive wholesale energy and capacity markets in New York State and how quickly those markets would develop and mature, the Company should have entered into longer-term parting contracts to protect its customers against the risk of higher prices. These parting contracts should have been two to four year agreements with the potential to protect customers during the expected transition period in New Jersey. Such contracts need not have covered all of RECO's capacity and energy requirements. However, contracts to provide about 50 percent of those needs would have been prudent.

As we will discuss in detail below, no other New Jersey or New York utility left itself as completely exposed to the potentially higher prices in the nascent spot markets as O&R. We also believe that, based on its approval of such two to four year transition power purchase agreements for other New York utilities, the New York State Public Service Commission ("NYPSC") would have approved such parting contracts for O&R.

To understand the context of RECO's exposure to the spot market, we first consider Orange & Rockland's situation as a regulated and vertically-integrated electric utility subject primarily to New York State regulation in the late 1990s. New York is one of the few states to undertake electricity restructuring without a legislative mandate. The NYPSC guided and mandated restructuring in a series of proceedings in Case No. 96-E-0900.

The NYPSC's directive to utilities was clear: it strongly favored vertical disintegration of utilities by divestiture of generation assets and the placing of transmission under the control of the NY ISO: "divestiture of generation is essential in the movement to competition, in order to avoid undue concentration of market power and the use of monopoly power on the distribution side." (Opinion No. 97-20, December 31, 1997, pp. 11-12, *In the Matter of Orange and Rockland Utilities, Inc.'s Plans for Electric Rate Restructuring Pursuant to Opinion No. 96-12)* In that order, and in an open session on November 6, 1997, and an order on November 26, 1997, the PSC approved O&R's restructuring plan.

Consequently, there was no opportunity for O&R to divest its generating units to an affiliate. The absence of a power plant owning affiliate, and the offers received by O&R in response to its September 1998 RFP for capacity and energy, effectively prohibited

O&R from being able to enter into a multi-year contract guaranteed at BGS price levels as PSE&G did.

O&R filed a Divestiture Petition with the NYPSC for approval of the sale of all of its electric generation assets to Mirant on March 12, 1999. The NYPSC approved that sale on June 24, 1999. The sale also was approved by the Board on that same date. The sale then was closed on June 30, 1999.

It is clear that the NYPSC strongly encouraged O&R to sell its generating assets as early as 1999. In fact, the sale of its generating assets was effectively a condition of the Company's acquisition by Con Edison, in order to avoid a high concentration of generation assets in the eastern New York market. But even if the NY PSC promoted the early divestiture of O&R's generating assets, the Company still maintained the responsibility of obtaining power for its customers at reasonable prices.

In evaluating the reasonableness of the parting contracts negotiated by O&R with Mirant, it is important to recognize the great uncertainty in 1998 and 1999 concerning the forthcoming New York State wholesale competitive capacity and energy markets. There was no evidence or basis for anyone to accurately predict how well the markets would function during their initial years, whether they would be competitive and how quickly they would mature and become liquid. There also was uncertainty about how many of RECO's existing customers would migrate to new energy suppliers and the rate at which such migration would occur. However, early experience from Rhode Island, California, and Massachusetts in 1998 suggested that customer migration would initially be limited.

The Company has acknowledged the great uncertainties it faced in 1998 and 1999 concerning the transition to the new wholesale capacity and energy markets in New York State and the likely prices in those markets once they opened:

- "Broker sheets did not give an indication of what NYISO prices would be prior to NYISO operations. The NYISO commenced operations on 11/19/99. There were not any reliable indications of NYISO prices prior to 11/19/99." (November 18, 2002 summary of interview of Joseph Holtman and Gary Rozmus)

- "The NYISO was functional in November 1999. The availability of sufficient information on pricing did not exist upon commencement of NYISO operations. Con Edison viewed this as an immature market." (November 19, 2002 summary of interview of Michael Forte and Adarsh Jain)

- "In 1999, it was at a very early stage of retail choice in NY. Plans had to consider that if load did not leave Con Edison or O&R or returned, that the utilities had an obligation to serve such customers and would be required to provide power for them. At that early stage, there was not a lot of information available and it was premature to say what portion of load would migrate under retail access." (November 19, 2002 summary of interview of Michael Forte and Adarsh Jain)

- "At this point, Mr. Bram offered his perspective that the utilities were concerned when deregulation was first discussed in the mid-1990s. He said to look at what the utilities such as Con Edison said in their testimony before the NYPSC. He stated that it was entities like ENRON and politicians who wanted to have open markets ….. As far as he is concerned, Con Edison did not know whether there would be lower prices for power once the NYISO market started operation." (November 20, 2002 summary of interview of Steven Bram, President of O&R since September 2000)

In fact, the responses to O&R's September 1998 energy and capacity RFP made it clear to the Company there were likely to be higher prices in the new markets, at least initially. As O&R's Director – Energy Resources, Joseph Holtman, noted in an affidavit he submitted in March 1999 in support of the Company's proposed TPSA and IESA:

- The small amounts of capacity offered in response to the RFP verified that the capacity market was then currently very illiquid and that O&R and its customers would face significant risks absent the TPSA.

- "… with respect to energy, only one bid was received that offered year-round supply, and the price, $37.75/MWH, far exceeded the offer price of the TPSA. Other prices for partial service were even less attractive. The uncertainty in the forward energy price market translates to high prices or no offers at this point. As with capacity, O&R and its customers would face significant risks absent the TPSA." (Affidavit of Joseph A. Holtman in NYPSC Case No. 96-E-0900, provided in response to RECO-ADR-S-67)

Mr. Holtman also noted in this affidavit that although the energy market was much more liquid than the capacity market, energy prices were "extremely volatile." He also emphasized that "Absent the "physical hedge" to prices provided by Company-owned generation, the Company needs a contract portfolio which includes fixed price contracts to hedge price volatility."

Unfortunately, the Company's response to this market and price uncertainty was to adopt a strategy whereby it would have to rely on these unproven and illiquid markets for nearly all of its energy requirements starting in April 2000 (a mere five months after the scheduled opening of the NYISO in November 1999) and nearly all of its capacity requirements starting in November 2000. This near total reliance was imprudent.

The steps taken by other New York utilities faced with the same market uncertainties support the conclusion that it was imprudent for O&R to completely expose their customers who retained full utility service to the spot and short-term markets. Most of these utilities entered into longer-term transition power agreements (as parting contracts are called in New York) and other agreements that provided for significant amounts of supply for several years after generation divestiture, at prices that were at least partly fixed. These contracts reduced their exposure to the spot markets.

New York State Electric and Gas
Like O&R, New York State Electric and Gas ("NYSEG") entered into agreements in late 1998 to sell fossil-fired generating units. The purchasers were AES NY Inc. and Mission Energy Westside, Inc. At the same time it sold these assets, NYSEG also entered into a transition power purchase agreement to buy 1,424 MW of installed capacity from AES NY through 2001, at a fixed price. It also entered into an option agreement with Mission Energy for the purchase of no more than 942 MW of capacity from NYSEG's divested Homer City unit. This option agreement was of the same duration as the agreement with AES. NYSEG also retained its share of the Nine Mile Point nuclear generating station Unit 2, some IPP contracts, and other generation resources.

NYSEG reported in its SEC Form 10k for the year 2001 that, as of December 31, 2001, it had hedges, generation and other electricity contracts "which provide for 97% of its expected electric energy requirements for 2002, 72% for 2003 and 68% for 2004."

Niagara Mohawk
Niagara Mohawk also divested hydro and fossil-fired generating units in 1999 and 2000. However, unlike O&R, Niagara Mohawk entered into multi-year transition power purchase agreements to buy power from the divested facilities' new owners. Niagara Mohawk also did not divest its 610 MW Nine Mile Point Unit 1 and its share of the capacity from the Nine Mile Point Unit 2 nuclear facilities until 2001.

Niagara Mohawk first sold 72 hydro units to Erie Boulevard Hydropower, LLC in mid-1999. When it did so, Niagara Mohawk also entered into a Transition Power Purchase Agreement that allowed it to purchase all of the electricity generated at the facilities at set prices during the period from the closing of the sales transaction through September 30, 2001. Niagara Mohawk described the Agreement as "a hedge against rising energy costs." (NY PSC May 27, 1999 Order in Cases Nos. 94-E-0098 and 94-E-0099, at page 22)

Niagara Mohawk also sold several coal-fired units to NRG, Inc., in mid-1999. When it did so, it also entered into three Transition Power Agreements with the units' new owner. One of these agreements ran through the time the NY ISO was fully implemented. A second agreement provided for the sale of power from a unit located within a load pocket. The third agreement (referred to as the Post-ISO TPA) was a swap transaction which was to remain in effect after the NYISO was implemented and terminate no later than the fourth anniversary following the closing date.

The Post-ISO TPA operated as a financial swap device. When the ISO energy price was lower than the contract variable price, Niagara Mohawk would make net payments to NRG, the new owner of the Huntley and Dunkirk plants. When the ISO energy price was higher than the variable contract price, NRG would make net payments to Niagara Mohawk. In addition, the agreement allowed Niagara Mohawk to claim installed capacity from Huntley and Dunkirk. (NY PSC June 7, 1999 Order in Cases Nos. 94-E-0098 and 94-E-0099, at page 9)

Finally, Niagara Mohawk sold its Albany Station to PSEG Power in May 2000. A related Transition Power Purchase Agreement between the two companies was to be in effect until September 30, 2003, or a period of more than three years. The provisions of this Agreement that were to survive the inception of the NYISO were financial in the form of a Swap Agreement. Instead of acquiring output, Niagara Mohawk would make fixed annual payments to PSEG Power. In return, it exercised the right to buy energy and capacity on the market, but at prices set by the Swap Agreement. According to the NY PSC, this enabled Niagara Mohawk "to access lower-priced power at times when the market price is high." (NY PSC Order in Cases Nos. 94-E-0098 and 94-E-0099, dated April 26, 2000, at page 11)

Central Hudson

Central Hudson Gas & Electric Corporation did not divest its Roseton and Danskammer generating units until the end of 2000. Moreover, when it did sell the units to Dynegy Power Corporation, Central Hudson entered into a Transition Power Purchase Agreement to buy capacity, energy and ancillary services at set prices for three years after the closing, with an option for a fourth year. Central Hudson also did not sell its share of the Nine Mile Point Unit 2 nuclear plant until 2001.

According to Central Hudson's Form 10-K for 2001, the TPPA with Dynegy, and an agreement with Constellation for power from the divested Nine Mile 2 nuclear plant together would provide approximately 42% of the Company's retail customer load requirements in 2002.

Con Edison

Con Edison divested certain of its in-City fossil-fired generating units in 1999, at about the same time as O&R. However, Con Ed retained significant generating assets that provided a hedge against higher market prices. For example, Con Ed did not divest its 480 MW share of the Roseton generating facility until the first quarter of 2001 and its approximately 1,000 MW Indian Point Unit 2 nuclear plant until the third quarter of 2001. At the same time, Con Ed maintained ownership of approximately 600 MW of electric generating capacity from its steam system facilities and a number of gas turbines. Con Ed also has had a 400 MW contract with Hydro Quebec and had contracts for 3,100 MW of NUG capacity.

In fact, an internal Con Edison presentation in January 2001, noted that 54 percent to 71 percent of Con Edison New York's energy requirements (depending on the month) were covered by "Company resources."

Rochester Gas and Electric Corporation

Rochester Gas and Electric ("RG&E") did not divest generating assets until it sold its share of the Nine Mile Point Unit 2 nuclear plant in 2001. As a result, RG&E obtained most of its requirements for the years 1999 through 2002 from its own facilities or under long-term contracts or unit commitments.

O&R has argued that the NY PSC discouraged it and other New York State utilities from entering into long-term parting contracts. O&R has suggested that the PSC did not want utilities to line up supplies under long-term power contracts, the argument being that if each utility required long-term buy-back commitments from the generators that purchased its generation assets, little generation supply would be available for the competitive market. According to O&R, the aim was for utilities to divest their generation assets without major buy-back commitments, so that power from those assets would be sold onto the competitive market, roughly matching the amount of demand that the utilities or, better yet, their retail customers would require from that market.

RECO witness Holtman even indicated in his interview that O&R could not have entered into transition power purchase agreements with the new owner of its divested generating facilities that extended beyond the inception of the new NYISO:

> The NYPSC wanted competition and Con Ed gave competition in NY a boost by not having long-term power supply agreements. O&R could not have entered into post-ISO transition purchase contracts with the new owner of its divested generation – nor were such contracts provided for under its restructuring settlement or its auction approval order – because such contracts would have hampered, if not totally constrained, the development of a wholesale market for electricity, which was the primary goal of divestiture. (October 29, 2002 summary of interview of Joseph A. Holtman)

However, O&R has acknowledged that there was no regulatory mandate from the NY PSC that would specifically have prevented it from entering into a power purchase contract that extended beyond the initial operation date of the NYISO. (Response to RECO-ADR-L-39). Moreover, an analysis of the generating asset divestitures of other New York utilities presents a different picture of the NYPSC's stance toward parting contracts. In divesting their generating assets, NYSEG, Central Hudson, and Niagara Mohawk all entered into parting contracts in 1998, 1999, and 2000 of at least three years in duration. All such contracts were allowed by the NYPSC:

- The NYPSC's April 24, 1998 Order in Case No. 96-E-0891 approved NYSEG's plan to auction its coal-fired generating facilities. The NYPSC specifically allowed NYSEG to develop transition power purchase contracts as part of the sale noting that:

  > Niagara Mohawk's entry into this type of contract has been approved, and NYSEG could be disadvantaged in the competitive market place if it is denied the same opportunity. Moreover, transition contracts will assist in ensuring that adequate supplies are available to meet the utility's provider of last resort (POLR) responsibilities to ratepayers that do not select competitive alternatives. (at page 20)

In December 1998 the NYPSC subsequently approved two year transition capacity agreements negotiated by NYSEG and the buyers of its divested coal-fired units. (Order in Case No. 96-E-0891, dated December 3, 1998, at pages 11 through 14) At that time, the PSC noted that it had previously determined that "NYSEG could proceed with negotiating transition contracts, so long as the pricing did not distort the wholesale market price or the auction sales price, and the output under the contracts was appropriately matched to [POLR] load." (at page 11)

- In May 1999, the NYPSC approved a two year transition power agreement between Niagara Mohawk and the purchaser of 72 of its hydro electric facilities. (NYPSC Order in Case No. 94-E-0098, dated May 27, 1999) The PSC Order specifically noted that the agreement "acts as a hedge against rising energy costs" and will enable the utility to meet its rate reduction goals and provider of last resort responsibilities. (at pages 22 and 23)

- In its June 7, 1999 Order in Case No. 94-E-0098, the NY PSC approved a four-year Transition Power Purchase Agreement entered into by Niagara Mohawk as part of the sale of its coal-fired generating facilities to NRG, Inc. The NYPSC noted that the transition agreements "act as a hedge against rising power costs and as a flexible source of power supply" and "at the same time, they provide NRG [the buyer] with a stable market at fixed prices for an interim period." (at page 20)

- In April 2000, the NY PSC similarly approved a three year Transition Power Purchase Agreement between Niagara Mohawk and PSE&G Power as acting "as a hedge against rising power costs." (NY PSC April 26, 2000 Order in Cases Nos. 94-E-0098 and 94-E-0099, at page 11) In its Order, the NY PSC noted that this agreement afforded the buyer, PSEG Power, "the security of stabilized pricing for an interim period." (Ibid*)*

- In December 2000, the NYPSC approved a three year transition power purchase agreement between Central Hudson Gas and Electric and Dynegy, the purchaser of its Roseton and Danskammer generating facilities. (NYPSC Order in Case No. 96-E-0909. dated December 20, 2000, at pages 11, 26, and 27) The NYPSC Order noted that Central Hudson had asserted that the agreement would assist it in fulfilling its provider of last resort obligations at stable market prices over the transition period. (at page 11). The NYPSC approved the agreement because its outcome provides a substantial benefit to ratepayers. (at page 27)

The NYPSC approved the NYSEG agreements and the concept of multi-year transition power purchase agreements in 1998, at the same time as O&R was negotiating the TPSA and the IESA. Thus, O&R should have known that the NYPSC would not deny its entrance into multi-year parting contracts and that such an agreement would be consistent with the commission's prior rulings. Moreover, in acting as a hedge against rising power costs and providing substantial benefits for customers, the parting contracts would have fulfilled the requirement cited by the NYPSC as justification for the acceptance of the transition power purchase agreements entered by the other New York utilities.

The three other New Jersey utilities besides RECO were members of PJM, a more mature market during the 1998/1999 timeframe. Nevertheless, each of these utilities adopted strategies to protect themselves and their customers against rising energy and capacity costs for longer periods than O&R. As a result, RECO's customers were more exposed to higher capacity and energy prices than the customers of any of the other New Jersey utilities. Consequently, it is not surprising that the State of New Jersey's Deferred Balances Task Force found that the approximate estimated deferred balances per customer for RECO were significantly higher than for the customers of any of the other New Jersey electric utilities. (Task Force Report, Chart 1, at page 11)

Power Contracts of Other New Jersey Electric Utilities

PSE&G entered into a full-requirements parting contract for the full three-year period during which it would be committed to providing BGS supply at fixed rates. Since the prices were equal to those recoverable under the BGS rate, PSE&G has no significant BGS deferrals.

Atlantic City Electric (ACE, now part of Conectiv) reported in its SEC Form 10-K for 2001 that as of December 31, 2001, its commitments under long-term purchased power contracts provided it with 1,800 MW of capacity (and varying amounts of firm energy), which is approximately 75% of its BGS capacity requirement.

Jersey Central Power & Light (JCP&L), like RECO, divested much of its generation capacity. JCP&L, when divesting its generating assets, instituted longer term parting contracts with the buyers, allowing it access to fixed prices as late as 2003. For example, in selling its fossil-fired units in November 1999, JCP&L negotiated the option of purchasing capacity at a fixed range of prices through May 2002. As part of the December 1999 sale of its 25 percent share of Three Mile Island Unit 1, JCP&L entered into a parting contract that allowed it to purchase the unit's energy and capacity through 2001 at fixed prices. Finally, as part of the August 2000 sale of JCP&L's Oyster Creek nuclear plant, the Company negotiated a parting contract that allowed it to purchase the unit's capacity and energy at a fixed price through March 31, 2003.

JCP&L nevertheless has had significant exposure to the spot and short-term contract markets. As of early 2002, the Company reported that long-term purchases from NUGs and owned generation accounted for less than 25% of its BGS requirements. Not surprisingly, JCP&L has the second highest per customer level of deferred balances, after RECO. (JCP&L has the highest deferred balance in absolute terms but has a far greater number of customers.)

Not only did O&R not enter into longer parting contracts, it also has admitted that it did not even quantitatively evaluate the potential costs and benefits of such contracts. For example:

- RECO-ADR-S-64 requested "copies of the analyses, assessments, evaluations, studies, memoranda, correspondence, and documentation which formed the basis for the decision to limit parting contracts to the period through the summer of 2000." RECO's response indicated that such documentation "is not available." Instead, the Company's business judgment was that it could not justify locking in costs that significantly exceeded retail rates, when those costs significantly exceeded expectations based on a fundamental analysis of the market. However, the Company did not provide the referenced "fundamental analysis of the market."

- RECO-ADR-S-69 requested copies of the analyses, assessments, evaluations and studies which formed the basis for or which supported the claim by RECO witness Holtman that "Given the purposes of the agreements and the circumstances present at [the time the Company entered into the parting contracts], it would not have been prudent to lock the System into such long-term supply agreements." RECO's response was that it "does not have specific documents related to this question." The Company's response also repeated the same general arguments that had formed the basis for the request.

- RECO-ADR-S-70 requested copies of any analyses, assessments, evaluations or studies prepared by or for the Company prior to the time it entered into the TPSA and the IESA which evaluated the costs and benefits of entering into longer-term agreements. The Company's response indicated that it had not quantitatively evaluated longer-term supply agreements.

- The Company's responses to RECO-ADR-S-79.b and RECO-ADR-S-80 indicated that the Company never explored the alternative of a full-requirements contract or hedging for all or part of the transition period commencing August 1, 1999.

The evidence we reviewed also suggests that Mirant would have been amenable to a parting contract with O&R of more than one year. For example, O&R has said that in the spring of 1999 Mirant offered to extend the TPSA beyond one year at prices that were approximately 20 percent above those charged to O&R for the first year. Unfortunately, this offer was only verbal and was not documented anywhere by O&R. (October 29, 2002 summary of interview of Joseph Holtman)

At the same time, Mirant was willing to enter into transition power purchase agreements longer than one year as part of its purchase of generating assets from companies other than O&R. For example, in December of 1997, Mirant acquired the 490-MW state line plant from Commonwealth Edison. The sale included a 15 year purchase agreement for the entire output of the plant. Then, in 1998, Mirant purchased 1,264 MW of energy from Commonwealth Energy and Eastern Utility Associates for $537 million. The deal included an agreement that Mirant provide power to both utilities for approximately five to six years to cover roughly a third of their standard offer requirements at a rate below market. Similarly, in the fourth quarter of 2000, Mirant purchased 5,154 MW of capacity from 4 generating stations and 6 purchased capacity contracts for 735 MW from PEPCO. An associated transition power purchase agreement was for three years.

At the same time, contrary to RECO's claim, there is no documentary evidence that Mirant would have significantly reduced its sales price bid for O&R's generating assets in exchange for longer parting contracts. (RECO Response to RAR-MTC-9) In fact, Company witness Holtman stated in his 1999 affidavit in NYPSC Case No. 96-E-0900 that the one year TPSA had a minimal impact on the bids that O&R received for its generation assets:

> O&R is not privy to the financial models of the bidders, and so it has no factual knowledge of the impact of the TPSA may have had on the prices bid. However, the bidders have not indicated that it had a negative impact on the bid price. Using the market data referenced above, it may be surmised that the capacity price might be attractive to a bidder, while the energy price was not attractive. On the balance, O&R believes the TPSA had a minimal impact on the bid prices.

Moreover, the NYPSC subsequently concluded in December 2000 that a three year transition power purchase agreement, with an optional fourth year, did not depress the price Central Hudson obtained for its shares of the Roseton and Danskammer generating facilities. (NYPSC Order in Case No. 96-E-0909, dated December 20, 2000, at page 27)

But even if Mirant had wanted to reduce its bid in exchange for a longer parting contract, prudent O&R management would have qualitatively and quantitatively evaluated the potential benefits and costs of the higher bid with the short-term parting contracts versus a lower bid with longer parting contracts. In other words, the benefits from a longer parting contract might have more than offset any reduction in the sale price. However, O&R management completely failed to make any quantitative comparison. Consequently, management could not know which was the superior option for protecting its customers and hedging against potential capacity and energy price increases in the new markets.

It seems that O&R gave precedence to selling its generating assets at the highest possible price over other generation planning objectives – such as hedging against higher prices in the not yet functioning New York markets. This is not surprising because the higher the sales price obtained for O&R's generation assets, the less would be the likelihood of stranded generation costs, and the greater would be the likelihood that the Company would gain from the sale. In fact, the Company stood to profit by sharing in any gain. As far as the New Jersey portion of the gain was concerned, the Company's share was not determined at the time, but it was later determined by the New Jersey Board to be 25%, with the other 75% going to customers. The Company also obtained a 25 percent share of its New York Share gain from the NYPSC.

RECO raises a number of points in its defense of the short duration of its parting contracts: RECO argues that "(s)ubstantial long-term liabilities were not advisable due to, among other things: the uncertainty regarding electric prices after the establishment of competitive wholesale markets (indeed, the New Jersey Legislature expected prices would fall as a result of competition...); the experience with mandated long-term Non-Utility Generator ("NUG") contracts that became uneconomical and resulted in enormous stranded costs; the potential for excess capacity charges after retail access penetration reduced RECO's (Provider of Last Resort) load; and the concerns raised during the divestiture process that development of the fledgling competitive market would be inhibited, and divestiture proceeds would be unduly depressed, if utilities entered into long-term purchase power agreements with the new owners of their former generating facilities." (Verified Petition, at page 11 and Direct Testimony of Joseph A. Holtman, at pages 15 and 16) The Company makes similar claims in its responses to our Audit Data Requests. For example, RECO's response to RECO-ADR-S-69 stated that "Given the purposes of the agreements and the circumstances present at the time, it would not have been prudent to lock the System into such long-term supply agreements." (RECO-ADR-S-69)

These arguments are not persuasive for a number of reasons.

First, we agree that O&R should not have entered into very long-term agreements when it divested its generation assets. However, the parting contracts need not have been for the "long term" beyond the transition period. Instead, O&R should have entered into two to four year parting contracts as hedges against rising energy and capacity prices, as other utilities faced with the same market uncertainties were doing.

Second, we have not concluded that O&R should necessarily have entered into a parting contract for 100% of the forecast requirements of its retail customers. A partial hedge against market price fluctuations, covering approximately 50 percent of those requirements during the transition period, would have been reasonable. This partial coverage would have allowed for migration of some retail customers to the competitive market. O&R's *near total* exposure to the spot market was imprudent.

Third, uncertainty regarding electric prices has the opposite implication to the one suggested by the Company. Uncertainty cuts both ways. Even if there was an *expectation* that prices would fall, uncertainty suggests that positions should be at least *partly* hedged against the opposite eventuality. The analytical revolution that has swept the financial markets during the past quarter of a century broadened the strategies of investors and corporate planners from a narrow focus on the *most likely* scenario to consideration of the *range* of scenarios that can reasonably be expected. A prudent strategy for O&R would have taken into account the significant possibility that electricity prices could be *higher* in a competitive market.

A parting contract with fixed prices based on historical costs was an obvious form of hedging against price uncertainty in the market. In an affidavit dated March 15, 1999, Mr. Holtman acknowledged that, "It also must be recognized that despite the loss, through divestiture, of its physical generation assets to hedge electricity supply costs, the Company must control price volatility to its electric sales customers." (Affidavit of

Joseph A. Holtman dated March 15, 1999, in NYPSC Case No. 96-E-0900) In the affidavit, Mr. Holtman discusses the potential difficulties of obtaining capacity until the *capacity* market is liquid. He then goes on to say, "*Energy* purchasing entails a different challenge. Although the market is much more liquid, energy market prices are extremely volatile. Absent the 'physical hedge' to prices provided by Company-owned generation, the Company needs a contract portfolio which includes fixed price contracts to hedge price volatility." Despite the recognition that energy markets can be "extremely volatile," even if "much more liquid," the Company did not enter into longer parting contracts, beyond the first year, to hedge against the possibility that prices would continue to be extremely volatile.

The evidence from the responses to O&R's September 1998 RFP for capacity and energy should have suggested that, in fact, it was not reasonable to *expect* with any certainty that prices would fall. For example, Company witness Mr. Holtman noted in his Direct Testimony that:

> In September 1998, (RECO) sought offers for capacity and energy in lieu of the TPSA. Thirteen bidders were solicited; for offers were received for capacity, two were received for energy. All of the bids contained unacceptable provisions or unacceptably high prices. (at page 14)

O&R also has said that, "The bids submitted [in response to that RFP] were substantially higher (approximately 45%) than the TPSA with Southern...The capacity offers...were also higher than the TPSA price..." (Response to RECO-ADR-S-68)

Mr. Holtman attributes these higher prices to "… the illiquidity of the market at that point in time." (Holtman Direct Testimony, at page 14) No doubt this is part of the answer. But there was no evidence that the market suddenly would become completely liquid by the second year of the transition period. In fact, O&R recognized the benefits of the TPSA and IESA as hedges against the risks of higher prices: "The uncertainty in the forward energy price market translates to high prices or no offers at this point. As with capacity, Orange and Rockland and its customers would face significant risks absent the TPSA." (Affidavit of Joseph A. Holtman dated March 15, 1999, filed with the NYPSC)

While it may have been reasonable to hope that these higher prices reflected only the current and not likely future market conditions after the first year of the transition period, it was not reasonable for the Company to rely on such speculation for nearly all of its energy and capacity needs. A longer term parting contract, covering a significant part of O&R's requirements, would have been prudent.

It should be noted, further, that O&R itself, like some other utilities, was skeptical about the new competitive markets. O&R President Stephen Bram "offered his perspective that the utilities were concerned when deregulation was first discussed in the mid-1990s...He stated that it was entities like Enron and politicians who wanted to have open markets, and there was lots of testimony from such interests claiming that competition would be great; however, the utilities said 'prove it.' As far as he is concerned, Con Edison and

O&R did not know whether there would be lower prices for power once the NYISO market started operation." (Summary of 11/20/02 Interview with Mr. Bram[28]) This skepticism should have reinforced a reluctance to *totally* expose RECO's customers to the new competitive markets during the transition period.

Fourth, the precedent of NUG contracts was not determinative. The price terms of those contracts were based on forecasts of the utility's projected avoided costs for literally decades into the future. This kind of forecasting is an error-prone exercise far removed from the medium-term, two to three or four year, alternative that O&R should have considered here.

Fifth, the Company says that one of its objectives was to "give retail access an opportunity to flourish" (Response to RECO-ADR-L-39), which is a reasonable objective, given the NYPSC's regulatory pressure to create a competitive market. "The NYPSC Staff was also concerned about entering into long term buy back arrangements as, in their view, it defeated the purpose of divestiture and worked counter to the goal of providing opportunities for customer choice to flourish." (Response to RECO-ADR-L-39). However, the argument that the development of the competitive market would be inhibited by a medium-term contract covering part of O&R's requirements implies that this is an either-or situation, which it is not. Markets take time to develop, and there was no evidence that the development of a competitive market would not have been unduly inhibited by a phase-in of both supply and demand. Moreover, as we have noted, the NYPSC specifically approved multi-year parting contracts and found that such contracts would not inhibit market development.

A related Company concern was the need to "manage the risk of customer migration." (Response to RECO-ADR-L-39) However, the Company already knew that customer migration could be limited: "(G)iven recent experiences in retail access, the Company expects to retain a significant share of its current electric sales market through the first year of full retail access." (Affidavit of Joseph A. Holtman dated March 15, 1999, in NYPSC Case No. 96-E-0900) Whether or not the complete lack of migration that actually occurred could have been fully anticipated, a parting contract for only part of the Company's requirements could have managed the risk that a significant number of customers would quickly leave for competitive suppliers. Furthermore, whatever the situation in New York, migration was much less likely to occur in New Jersey where the development of a market was inhibited by the artificially low price of Basic Generation Service.

Sixth, another Company objective was to "avoid unduly reducing the sale price of the generating units." (Response to RECO-ADR-L-39). We have referred to this objective above, where we noted that the Company focused on the issue of reducing stranded generation costs and perhaps benefiting from retaining a share of the gain on the sale. This was, of course, a valid objective. However, the parting contracts need not have been so "long-term," or onerous to buyers in other respects, that they need have depressed the

[28] Note: Mr. Bram was not President of O&R in the mid-1990's. Rather he was an employee of Con Edison at that time.

sale price of O&R's generating assets and reduced the contribution of those sale prices to stranded cost reduction. O&R has claimed that "(F)rom the new generation owner's perspective, a long-term obligation to the previous owner would preclude benefits of managing those assets in the new market." (Response to RECO-ADR-S-69) Perhaps so, but it would also reduce the asset owner's *risk*. From the standpoint of a generation owner, a contract for part of the output of the facilities during a transition period at prices that covered costs would provide a partial assurance of cost recovery that would be lacking in the competitive spot market. Such a sale would be a hedge to the seller -- it would cover what would otherwise be an open long position in the market, ownership without an assured price for its product. The Company cites evidence that "the asset buyer (i.e. Southern Energy) sought to engage 'in external bilateral sales of energy and power at wholesale.'" (Response to RECO-ADR-L-39) This appears to confirm Southern Energy Affiliates' willingness to commit to power sales.

In fact, as we have noted, the NYPSC found that multi-year parting contracts provided the buyer with "a stable market at fixed prices" and "the security of stabilized pricing" for an interim period. (NYPSC Order in Case No. 94-E-0098, dated June 7, 1999, at page 20, and Order in Cases Nos. 94-E-0098 and 94-E-0099, dated April 26, 2000, at page 11)

Seventh, the New Jersey regulatory situation also should have encouraged O&R to enter into longer-term parting contracts. The fact that RECO is in New Jersey means that O&R had to take into account the requirements of RECO's New Jersey customers and the New Jersey Board of Public Utilities, as well as those of its New York customers and the New York PSC. We acknowledge that the Board approved the sale of O&R's generation assets, including its parting contracts with Southern Energy Affiliates, in an order dated June 24, 1999. The Board noted that the balance of RECO's BGS requirements "will be procured by means of a strategy that will consider a combination of products including, but not limited to, spot market purchases and short-term advance purchases, including bilateral contracts and/or financial instruments such as hedging." Clearly, the Company retained the responsibility to develop a prudent transition strategy, including giving special consideration to the situation of RECO's customers, subject as they were to restructuring legislation in New Jersey.

The Electric Discount and Energy Competition Act (EDECA), which was signed into law by Gov. Whitman on February 9, 1999, mandated rate reductions for the New Jersey's electric utilities, and required that they would have to offer Basic Generation Service. As and when it became clear that RECO's customers would have fixed BGS rates for a transition period, O&R should have entered into a medium-term power supply agreement with the purchasers of its generation assets to cover this load at prices that were reasonably consistent with the rates that were set by the Board.

The terms of New Jersey's restructuring were finalized later than New York's. The Board issued its Summary Order in 1999, and its Final Decision and Order only in July 2002. It was on August 1, 1999 that the four-year transition period with its fixed BGS rates for RECO began. However, by November 1998 when O&R entered into the TPSA RECO should have anticipated that it would be required to supply BGS for a period of several years at tightly controlled prices. It might be difficult for utilities to obtain supplies at these prices, and it might also be difficult for retail customers to obtain better alternatives, meaning that they might be more inclined to retain utility BGS service.

Whether or not O&R's actions were appropriate in the context of New York regulation, they were not appropriate in the context of New Jersey regulation. O&R failed to fully take into account the needs of RECO as a regulated New Jersey utility.

The scope of the parting contracts was too narrow. "The terms of these agreements were established to bridge the time period from divestiture of the generation assets to commencement of NYISO operations, which would also coincide closely with the bulk of (New York Control Area's) asset divestitures." (Response to RECO-ADR-S-69) The scope should have included the provision of at least some part of RECO's requirement as a New Jersey utility to provide BGS at regulated rates for a multi-year transition period. The design of New Jersey's BGS rates, furthermore, contrasted with that of New York. RECO's New Jersey BGS rates were set by the Board in its July 28, 1999 Summary Order and were to increase slightly over the four year Transition Period. (See Summary Order at p. 6.) In contrast, O&R New York could adjust its recovery monthly to reflect a pass-through of purchased power costs. This made it more likely that retail customers would stay on BGS rates in New Jersey, rather than migrating to competitive suppliers. It also meant that deferrals would build up unless purchased power costs could be kept under the amount recovered under the BGS rate. Were these factors taken into account by O&R? Here is what the Company has to say.

> The Supply Department's purchases and strategies were the same for all members of the O&R system, that is, to procure least cost generation services on behalf of full service customers. All members of the System (O&R, RECO and Pike) had the same obligation to provide generation services to customers that did not choose a third party supplier. Although each state had different retail recovery provisions, this did not change the strategy of Supply Department. Indeed, while O&R has a monthly market-based Market Supply Charge (as proposed by RECO in its restructuring proceedings before the NJBPU), RECO's NJBPU-approved restructuring plan allows for the deferral and ultimately recovery of differences between BGS costs and revenues. Thus, these recovery mechanisms achieved a similar result. (Response to RECO-ADR-S-87)

It does not appear that at the time the parting contracts were entered into O&R fully considered RECO's situation as a New Jersey utility regulated by the Board. The Company's arguments generally refer to O&R collectively as a New York utility. "Once the NYISO commenced operation and retail access was implemented, it was expected that customers would migrate to other suppliers." (Response to RECO-ADR-S-69) This was more likely to be true of O&R's New York customers than of RECO's New Jersey customers. Indeed, as of April 2000, out of approximately 70,000 customers, RECO had only 9 customers shopping (3 residential and 6 non-residential).

Eighth, as we have previously noted, there is no evidence that a multi-year parting contract would have significantly lowered the price that O&R would have been able to obtain for its generation assets.

Finally, we note that a multi-year parting contract covering perhaps 50 percent of the Company's expected requirements would have been consistent with the Company's subsequent hedging approach (discussed in the following section), which was to enter into partial hedges against price spikes. By the summer of 2001, the O&R guideline called for hedging approximately 50% of its generation requirements. Unfortunately, by that time prices had already risen, and the opportunity of a built-in hedge in the form of parting contracts, had been lost. To prepare for the future in an economically prudent manner, at the time of the sale of its generation assets to Mirant, RECO should have more adequately protected itself and its customers against future market fluctuations during the transition period in New Jersey.

Chapter 8 - The Transfer of RECO's Eastern Division to PJM

This Chapter addresses the analysis and timing of the transfer of RECO to PJM and answers the following question in the Task Force Report:

- Why didn't RECO join the PJM system earlier?

Con Edison objects to the suggestion that it "waited" before transferring RECO's Eastern Division, which contains about 90% of the Company's load, from the control area of the New York ISO to that of PJM: "Rather, the RECO Transfer, which occurred on March 1, 2002, was the culmination of a complex and painstaking process that occurred over a period of time." (Response to RAR-MTC-54)

To examine whether the transfer was imprudently delayed, we have developed a detailed chronology of the events that led up to the transfer.

11/18/99. The chronology begins with the NYISO's start date, which was delayed from September 1, 1999 to November 18, 1999, at which time the NYISO instituted a day-ahead market (DAM) and a real-time market (RTM) for spot energy. The prices are zonal, and O&R is in Zone G, one of New York's eleven transmission zones. Most purchasing by O&R and other utilities is in the day-ahead market. The real-time market is narrower and prices are more volatile, especially during peak hours, 7 AM to 11 PM, Monday through Friday, excluding holidays.

NYISO also instituted an installed capacity market (ICAP) for three regions, New York City, Long Island and rest-of-state (ROS), O&R being in the ROS area. On November 1, 2001, NYISO switched to a monthly purchasing period for what was now called unforced capacity (UCAP), and required each load-serving entity (LSE) to line up capacity equal to its peak demand plus an 18% reserve margin.

The Pennsylvania-New Jersey-Maryland Interconnection (PJM), meanwhile, had been operating a real-time market since 1997. PJM added a day-ahead market on June 1, 2000. It also operates a UCAP market. Both NYISO and PJM administer ancillary services markets for such services as black start capability and voltage support.

11/99. Some people had expected the NYISO to produce lower prices. "The day the NYISO market opened, prices went up. From that point, Mr. Bram (O&R's President) realized that prices would be higher." (Summary of interview with Mr. Bram, 11/20/02)

1/00 onwards. NYISO's energy prices, which account for the greater part of electricity costs, were higher than PJM's from the outset. While PJM's energy costs were lower, its capacity market was initially volatile, which somewhat reduced the advantage of buying in that market. More important, perhaps, is that it took a while to develop a comparative track record of relative prices from which to infer that prices in the NYISO spot market would be lower than those in PJM on a continuing basis. Meanwhile, in Mr. Holtman's words (Direct Testimony, p. 17), "There was no reasonable basis to believe that PJM would produce more favorable wholesale prices for RECO than the NYISO." Once that determination could be made with reasonable certainty, a cost-benefit analysis could be performed. The costs were not insignificant, including improved ("revenue grade") metering, and new telecommunication systems.

1/00-5/00. By January 2000, the initial performance of the NYISO markets was being evaluated in the trade press, including *Power Markets Week* and *Power Economics*. Initial reports during the period January through May 2000 are largely critical, focusing on the ancillary markets for reserve capacity, which exhibited price spikes.

6/00. Pricing problems continued in the NYISO area, and in June 2000, price caps were approved for certain NYISO products. "Prices started going up during the summer of 1999. These price increases continued in 2000, and did not abate until 2001. Con Edison had difficulty in assessing how long the price increases would persist...During the summer of 2000, O&R/Mr. Bram noticed that prices were consistently higher than the BGS rate...The summer of 2000 was the defining time when O&R realized that energy prices were clearly higher. Gas prices (which are correlated with electricity prices) were higher and forward pricing showed that gas prices were expected to remain higher." (Summary of interview with Mr. Bram, 11/20/02)

9/00? In the fall of 2000, Mr. Stephen Bram, President of O&R, asked that the transfer of RECO to PJM be investigated. After the summer of 2000, he thought that energy prices in general were going up, and it made sense to investigated whether PJM prices were, and were expected to be, lower than those in New York. At that time, no company had transferred from one ISO to another. (Summary of Interview with Mr. Bram 11/20/02)

9/00? A study of the economics of transfer was performed. "RECO accumulated detailed price data on NYISO and PJM for use in a study regarding the economics of transferring RECO's Eastern Division to PJM. Price data for a reasonable period needed to be accumulated to make a meaningful comparison. NYISO prices did not show major volatility until June-September 2000. During the Summer 2000 period PJM (UCAP) prices exhibited major volatility, with UCAP prices being as high as $9.30/kW-month. In contrast, the NYISO installed capacity prices were approximately $1.50/kW-month during the same period. The addition cost of PJM UCAP, which raised questions regarding both PJM's underlying economics and market stability, called the transfer of RECO's Eastern Division to PJM into question." (Response to RAR-MTC-54)

10/00. NYISO's capacity market was not immune from problems. In an October 2000 news release, NYISO's Board of Directors identified inadequate generating capacity, lack of price-sensitive load, and the absence of incentives for transmission expansion as the causes of the high prices for reserve capacity. NYISO had previously blamed generators for manipulating the market by holding back capacity. FERC had laid some of the blame on the practices of the NYISO itself.

1/00 onward. Arguably, the volatility of NYISO ancillary services prices during 2000 could be regarded as start-up problems that would respond to mitigation measures. However, as noted earlier, in each month in 2000, spot energy prices were higher in the NYISO market than in PJM.

11/00. "In November 2000, after the PJM UCAP prices settled to reasonable levels, RECO began discussions with PJM regarding the transfer of RECO's Eastern Division (which is physically connected to PJM) to PJM. (Response to RAR-MTC-54) The discussions were "to identify and explore technical issues surrounding a transfer of RECO to PJM." (Mr. Holtman's Direct Testimony, p. 20)

12/00. "RECO's first meeting with PJM was held in December 2000." (Response to RAR-MTC-54)

12/29/00. PJM sent a very positive email to Con Edison, proposing a January 10, 2001 meeting, following an internal PJM meeting on January 3, 2001, at which "a list of questions and data requirements for Con Ed" would be prepared. On January 4, after that meeting, PJM notified Con Edison of a number of technical and operational issues related to revenue quality metering, telecommunications, etc., and requesting data.

1/12/01. On the agenda of the proposed Con Edison-PJM meeting -- the second such meeting, and apparently delayed to January 12, 2001 -- were a number of items, including "required PJM studies," reviews of metering, telecommunications and settlement requirements, operations and control room processes, and training.

1/31/01. An internal Con Edison memo referred to "the evaluation we are doing to move the RECO into the PJM control area."

1/01-4/01. During the January to April 2001 period, utility and NYISO news releases and reports identified, among other factors, a mismatch between supply and demand in New York as a continuing source of problems and price pressures. For instance, a January 22, 2001 report by Con Edison Chief Engineer Bill Jaeger identified a number of problems in the NYISO markets. These included known design flaws, the potential to exercise market power under high load conditions, and demand growth outstripping generation additions.

1/01-6/01. During the January to June 2001 period, "PJM capacity prices had become dysfunctional...such prices became close to what NYISO capacity prices were in New York City. Those prices are typically higher than for NYISO Zone G (in which O&R is situated)." (Summary of Interview with Michael Forte and Adarsh Jain, 11/19/02) It seems that there were during this period problems in both NYISO and PJM capacity markets.

2/13/01. Con Edison's Supply Department made a presentation to O&R's Corporate Policy Committee, which addressed the costs and benefits of the transfer. That presentation confirmed that in every month in 2000, PJM's spot energy prices had been significantly lower than NYISO's. The averages were $28.96 and $44.78 per MWh respectively. However, the presentation noted that, "Currently PJM ICAP market (is) clearing at 4 times the NYISO market -- $5.00 per kW month vs. $1.25 per kW month." (At these comparative capacity price levels, the capacity cost penalty resulting from transferring to PJM would be approximately $10 per MWh, assuming a load factor of 50%. If sustained, this penalty would eliminate most of the energy cost advantage of the transfer.) The next steps listed in the presentation were to continue discussions with PJM, coordinate with NYISO, and "monitor ICAP market developments in PJM."

3/13/01. There was a further PJM/Con Edison meeting to discuss metering, analytical studies, control room operating issues, training courses for operators and for ICAP markets.

4/20/01. There was a meeting at which Con Edison explained the details of the transfer to NYISO and discussed technical and PR issues. According to an internal Con Edison memo, "The meeting was very productive because NYISO did not appear uncooperative." NYISO agreed that there would be no ancillary charges or NYISO transmission charges (Tucks) for the transferred loads.

1/01-6/01. "UCAP prices in PJM showed extreme volatility from January to June 2001. These UCAP prices stayed at approximately $5.20/kW-month and peaked at $9.30/kW-month. These high UCAP prices in PJM would have adversely affected the economics of the RECO transfer. The PJM UCAP markets started to improve in June 2001." (RECO Response to RAR-MTC-54)

6/6/01. In an order in Docket EX1050303, the Board directed RECO to participate in a statewide BGS auction for Year Four of the transition period, commencing August 1, 2002. Participation in that auction is facilitated by the transfer of RECO's Eastern Division to PJM.

6/01. An Excel spreadsheet titled *Economic Analysis of Transfer of RECO Loads to PJM* was prepared. It was provided to the Audit Team as an attachment to RAR-MTC-56. Total net savings from transfer were estimated at $12.9 million for 2001, $21.4 million for 2002, and $25.0 million for 2003.

6/13/01. A second presentation by the Supply Department to O&R's Corporate Policy Committee addressed the costs and benefits of transfer. Comparative data showed that the energy price differential in favor of PJM was sustained through May 2001 and reflected in forward prices for 2002 and 2003. In that presentation, the "actions taken to date," were listed as, "meetings with PJM, Joint Meeting with PJM and NYISO, Technical studies by PJM, (and) Technical studies by Con Edison & Orange and Rockland." PJM's ICAP charge, furthermore, was expected to decline substantially and fall below NYISO's in 2002 and 2003. Charges for ancillary services such as reactive supply and voltage control were estimated as lower in PJM than NYISO. Total net savings from transfer were estimated at $12.9 million for 2001, $20.7 million for 2002, and $24.7 million for 2003, slightly different but essentially similar to those in the version of the spreadsheet referred to above. Technical issues were discussed, regulatory filings with NYISO, PJM and FERC, and schedule. The target transfer date was given as October 1, 2001.

6/25/01. A presentation by the Supply Department to the Con Edison Corporate Policy Committee addressed the costs and benefits of transfer. The information presented was similar to that presented to O&R twelve days before. However, the savings estimates were slightly different. Total net savings from transfer were estimated at $8.3 million for 2001, $20.7 million for 2002, and $27.7 million for 2003. The target transfer date was again given as October 1, 2001.

6/01. "RECO gave the final go ahead to PJM for undertaking the capital expenditures for communication and other equipment in June 2001." (RECO Response to RAR-MTC-54)

7/11/01. At a meeting between Con Edison and PJM, the facilities to be transferred to PJM control were described, and FERC filings, rate issues, and PJM agreements and membership issues were discussed.

7/01. "RECO and PJM started preparing the petitions to FERC requesting the RECO Transfer in July 2001, in anticipation of the successful completion of PJM's stakeholder process. RECO and PJM representatives met with the FERC staff on July 26, 2001. (RECO Response to RAR-MTC-54)

7/01. "In July 2001, PJM initiated the stakeholder process, through various committees, to consider the RECO Transfer. PSE&G opposed the RECO Transfer at these committee meetings." (RECO Response to RAR-MTC-54)

7/01. "Processes for the installation of communication and metering hardware were initiated in July 2001." (RECO Response to RAR-MTC-54) The minutes of an O&R Board Meeting on July 18, 2001 refer to "RECO's application to transfer its load from the New York Independent System Operator to the Pennsylvania-New

Jersey - Maryland ISO, which would permit lower cost PJM power to be streamed to RECO."

8/25/01. "The RECO Transfer proposal was present to the PJM Members Committee on August 25, 2001. As a result of vehement objections by PSE&G, the PJM Members Committee failed to endorse the RECO transfer." (RECO Response to RAR-MTC-54)

9/11/01. "Because of the September 11, 2001 terrorist attack, the installation of necessary communication equipment was delayed." (RECO Response to RAR-MTC-54)

10/1/01. "The RECO Transfer then was presented to the PJM Board of Managers, who approved it at its October 1, 2001 meeting." (RECO Response to RAR-MTC-54)

10/4/01. "The PJM Board of Managers' decision was announced at the October 4, 2001 PJM Members Committee meeting. PSE&G again made a strong statement in opposition." (RECO Response to RAR-MTC-54)

10/17/01. RECO and PJM submitted a Joint Application to FERC for approval of the RECO transfer. According to Con Edison, the purpose of the transfer was "primarily to facilitate RECO's participation in the Board-approved (BGS) Auction." (RECO's response to RECO ADR-S-65) "PSE&G and several other parties filed motions to intervene and protest." (RECO Response to RAR-MTC-54)

11/01 (approximately). "The Company retained Charles River Associates to assist it in evaluating and responding to the issues raised by the PSEG companies in opposition to the proposed transfer. Charles River Associates, which was retained after the Joint Application was filed, did not assist the Company in evaluating whether to transfer the Company's Eastern Division to PJM." (Response to RECO-ADR-L-110)

12/17/01. FERC approved the necessary amendments to the Power Supply Agreement between RECO and O&R, enabling RECO to purchase on its own behalf some or all of its electricity requirements.

12/21/01. FERC approved the RECO Transfer by order dated December 21, 2001.

1/9/02. An internal Con Edison memo discussed the proposed agenda for January 10, 2002 meetings with NYISO, including timeline of the transfer, technical issues, training needs, FERC filing, hand-over process from NYISO to PJM, etc.

1/10/02. The meeting of Con Edison/O&R and NYISO took place. A number of technical and operation issues were discussed. The NYISO said it would be ready for the transfer by February 1, 2002.

1/10/02. An internal Con Edison memo listed a number of hurdles that would have to be overcome to meet the planned March 1, 2002 transfer date. These included testing of circuits and installation of meters.

3/1/02. Transfer was effectuated on March 1, 2002.

In our assessment of the timeliness of the RECO Transfer, we divide the chronology into eight periods, one (period zero) prior to November 18, 1999, when the NYISO was formed, and seven subsequent periods totaling 27 months and culminating in the transfer on March 1, 2002:

0. The period leading up to the formation of the NYISO on November 18, 1999.

We considered setting the start date of our chronology before the start-up of NYISO, based on the history of lower electricity *costs* in PJM compared with the New York Power Pool, NYISO's predecessor. RECO has said it did not evaluate such a transfer as of the date of August 1, 1999, and has argued that "data from which such a study would be prepared were insufficient." (Response to RECO-ADR-S-73) We agree that it would be demanding too much of O&R and of Con Ed's Supply Department to find that they should have anticipated, based on the historical comparative cost data, that the new NYISO markets would with reasonable certainty have higher market prices than PJM's.

Con Edison argues as follows: "Mr. Holtman agrees that relative generation costs provide a basis for expected relative market prices during off-peak periods and non-peak months. However, during summer peak periods, opportunity costs, risk premiums, congestion and transmission losses significantly weaken that basis." (Response to RECO-ADR-S-81)

Testimony filed in RECO's Stranded Cost and Rate Unbundling proceedings, BPU Dockets. No. E97070464/465, dated January 21, 1998, supports the view that there was considerable uncertainty about future price trends in PJM and New York. This is exemplified by the testimony of Division of Ratepayer Advocate witness Doug Smith, who based his market price projections on simulations of the PJM system. "In order to approximate RECO's stranded generation costs at this time, I have assumed that O&R's generation resources will receive revenues from the competitive market at a level somewhat above my PJM results." However, he notes that, while New York is projected to have excess generating capacity through 2005, PJM is projected to need capacity earlier. (Direct Testimony, p. 18) This suggests that capacity prices and peak period prices could be higher in PJM than in New York in certain years.

New plants were being built, the structure of the increasingly competitive markets was evolving, and the hope was that prices would tend to equalize as "seams issues" between different control areas were resolved. It was also in the cards that a Northeast ISO, incorporating both NYISO and PJM, would be mandated by FERC. In an analysis prior to the start date of the NYISO, O&R used PJM prices as a proxy for NYISO prices, implying that it expected prices in the two areas to be similar. This does not seem to have been an unreasonable assumption to make, until it became clear that the Northeast ISO was not going to be created any time soon, seams issues would remain significant, etc.

1. <u>The period November 18, 1999 through August 2000 -- Waiting while comparative price data accumulated (9 months)</u>.

   During this period, the evidence of high NYISO prices -- prices that were higher than PJM's prices -- accumulated. NYISO prices were higher from the outset, as reflected in an O&R assessment which uses data back to January 2000. However, PJM capacity prices were "dysfunctional." No formal steps, either internal or external, were as yet taken by O&R. This period concluded with summer 2000, the first peak season during which the NYISO was operating.

2. <u>September 2000 through November 2000 -- Formal Evaluations by Supply Department (3 months).</u>

   In about September 2000, O&R, and Con Edison's Supply Department, started to formally investigate the economic and other features of the transfer. Around November 2000, it seems the conclusion was reached in the Supply Department that the transfer was likely to be economic, provided pricing in PJM was not highly volatile, and that it now made sense to approach PJM for the first time.

3. <u>December 2000 to May 2001 -- Internal and External Evaluations, Presentations and Discussions (6 months)</u>.

   Meetings with PJM and NYISO, as well as further internal O&R and Con Edison presentations by the Supply Department, including ongoing evaluation of price volatility in PJM.

4. <u>June 2001 through July 2001 -- Approval and Implementation Process Begins (2 months)</u>.

   Notification of PJM that O&R wanted to go ahead, and that work should start. Initial steps taken to prepare for installing new equipment. Target date set for October 1, 2001.

5. <u>August 2001 through September 2001 -- Delays (2 months)</u>.

   Objections by PSE&G delayed PJM decision process, as did September 11-related work problems. Around this time, Charles River Associates was hired by O&R to analyze the transfer, apparently for purposes of persuading PJM that the transfer was reasonable. No outside consultants had been hired to analyze the transfer up to this point in time.

6. <u>October 2001 through December 2001 -- Completion of approval process (3 months)</u>.

   On obtaining agreement by PJM's Board, O&R and PJM jointly applied to FERC for permission for transfer, which was obtained in December 2001.

7. <u>January 2002 through February 2002 -- Final implementation (2 months)</u>

   Equipment installed, personnel prepared, etc., culminating in transfer March 1, 2002.

We consider this 27-month chronology one period at a time, in light of the information available to RECO and to Con Edison's Supply Department during each period. We group the periods into three nine-month phases.

Period 1 lasted for nine months – November/December 1999 through August 2000 -- and accounted for one third of the 27-month period. During this period, the Company waited while data accumulated. While this seems like a long time, we note that the period could be considered a build-up to the summer of 2000, the first summer during which a direct comparison could be made between PJM prices and prices on the new NYISO.

The second nine-month phase consisted of Periods 2 and 3 and lasted from September 2000 to May 2001. During Period 2, formal evaluations of the transfer were conducted in Con Edison's Supply Department. After this three-month period, the transfer appeared economic, and in Period 3, which lasted six months, there were internal and external presentations, including meetings with PJM and NYISO. These periods together accounted for a further nine months. Two thirds of the 27-month chronology has now been accounted for.

This second nine months seems like a long time in retrospect, but there are certain factors that should be considered. One of these was that the functioning of the new SOS was being scrutinized, and the possibility of a regional ISO was under review. The second was that continuing uncertainties about the SOS was underscored by the capacity market volatility in both NYISO and PJM, the volatility in the latter control area lasting until June 2001. Third, this was the first time there had been a proposed transfer of an area from one ISO to another. Fourth, Con Edison had to present the idea to both the New York ISO and PJM. If the transfer had been given top priority, perhaps this phase could have been reduced somewhat. In a fast-changing industry, however, management has a number of things to do in parallel. We think it is difficult to conclude that the pace at which Con Edison management moved was so slow as to be imprudent. After all, management did move forward steadily, if somewhat slowly.

Periods 4 through 7, making up the third nine months of the chronology – June 2001 through February 2002 -- were taken up with technical matters, as well as the approval process within NYISO and PJM, and with the various regulatory agencies concerned, primarily FERC. There were delays in both the technical and regulatory processes: the September 11, 2001 attack on the World Trade Center set back some of the technical work, and PSE&G vigorously opposed approval by PJM. Given these delays, the technical investigations, the procurement and installation of equipment, and the inherent difficulty in dealing with other organizations or entities, we conclude that RECO, or Con Edison on its behalf, acted with all deliberate speed during this period.

In light of the above discussion of the three nine-month phases of the transfer process, and on the information available to us, we do not conclude that the Company acted imprudently in arranging for the PJM Transfer. The transfer itself was undoubtedly a good idea. And, in our opinion, the timing was not unreasonable. In response to the question raised by the Task Force Report, we do not believe the Company was imprudent in not joining the PJM system earlier.

Chapter 9 - Cost Mitigation Efforts – Hedging Program

The next question is whether O&R, or, after August 1, 1999, Con Edison's Supply Department on its behalf, took appropriate steps to mitigate electricity supply costs for BGS service by hedging or contracting. The appropriate mitigation strategy would be an attempt to make up for the missed opportunity to hedge against cost increases by entering into a medium-term parting contract. If that opportunity had *not* been missed, there would have been no need for further mitigation, and the net costs of any subsequent mitigation strategy would not have needed to be incurred. Although no hedging costs were incurred in the first year (August 1, 1999 through July 31, 2000), these net hedging costs were significant in the following two years -- $6,932,000 in the 12 months ending July 31, 2001, and $4,662,000 in the 12 months ended July 31, 2002. (Testimony of Frank P. Marino, Exhibit FPM-2, pages 3 and 4.)

It should be noted here that Con Edison itself retained considerable "physical hedges" by its continued ownership of generating capacity. According to an internal presentation dated January 2, 2001, 54% to 71% of Con Edison New York energy requirements (depending on the month) was covered by "Company resources." It seems that O&R alone was left almost totally exposed to the spot electricity market after its short-term parting contracts with Mirant ended.

Our analysis in this section will answer the question asked in the Task Force Report: "Did utilities make reasonable decisions about purchasing power in the deregulated market?" The Supply Department did in fact develop a sophisticated program for entering into hedges or other contracts for subsequent capability periods, with particular emphasis on the summer capability periods during which tighter markets were more likely to result in high prices. RECO outlined the elements of a procurement strategy in Paragraph 9 its Restructuring Plan filed with the BPU on July 13, 1999, and approved in the Btu's Summary Order of July 28, 1999. The strategy would "consider a combination of products including, but not limited to, spot market purchases and short-term advance purchases, including bilateral contracts and/or financial instruments such as hedging."

Without the "physical hedge" of owned generation, or the equivalent hedge of a medium-term parting contract, the Supply Department did in fact consider entering into hedges or other contracts for subsequent capability periods, with particular emphasis on the summer capability periods during which tighter markets were more likely to result in high prices.

In February 2000 the Supply Department solicited quotes from several market participants for energy for the Summer 2000 capability period (June through September). Only one bid was received for Zone G. It was for less than 20% of O&R's requirement, and was for the high price of $84.50 per MWh (8.45 cents per kWh). Mr. Holtman (Direct Testimony, p. 18) reports that, "The Supply Department concluded that the immaturity of the NYISO market at the time was the primary reason for the small amount of energy offered by the market participants. For this reason, no hedges were entered for the summer of 2000."

The Company addressed this matter further in response to data requests. "As noted in the testimony of Mr. Holtman at page 18, lines 1 through 8, the Supply Department sought price hedge opportunities in Spring 2000. At that time, forward prices (for Summer 2000, to which the costs of hedging during that summer period were related) greatly exceeded the Supply Department's expectations. The Company therefore chose to rely on the spot market. However, it was expected that the market would be more mature in Summer 2001, so the Supply Department sought hedge opportunities for that period through the November 30, 2000 RFP." (Response to RECO-ADR-S-83, explanatory material in parentheses added) "At that time, the Department expected that summer prices would reflect generators' operating costs more closely than actually happened. The response significantly exceeded this outlook, and therefore was not accepted." (Response to RECO-ADR-S-74)

It should be added that in early 2000 the NYPSC Staff was still skeptical about financial hedges. In light of the information available to the Company at the time, as well as regulatory skepticism, the decision *not* to enter into any hedges for Summer 2000, does not appear to have been imprudent. However, this experience confirms that when O&R failed to enter into medium-term parting contracts as part of the sale of its generation assets, it could no longer hold down its purchased power costs, even if it entered into physical or financial contracts or hedges. It had let the horse out of the barn prior to August 1999.

On November 30, 2000, the Supply Department issued an RFP for alternative sources of power for periods such as the Summer 2001 capability period. While nine counterparties responded to the RFP with a variety of offers, none of them was a fixed-price bid, and the Company concluded that they did not offer savings compared with the market prices that it expected. While this assessment does not assess the eventuality that actual prices might exceed forward prices, it was clearly O&R's view that the contracts were too expensive.

An internal Con Edison presentation dated January 2, 2001 outlined a strategy for 2001, including the optimal percentage of load covered, and a proposal to review the plan with the NYPSC. Among the action items in an internal memo dated January 10, 2001, referring to Con Edison New York, was an item "to obtain all necessary executive and board approvals to buy the physical energy or do the financial deals."

Reference was made in that memo to "political cover," and in the January 2, 2001 presentation, the Hedging Strategy Objectives were given as reduction of monthly price volatility and "viewed as prudent by regulators." It seems that part of the reason for entering into at least minimal hedging in January 2001was to satisfy the concerns of NYPSC staff, who had by that time become anxious about price volatility after the extreme volatility experienced in Summer 2000. We note, however, that the hedging goals developed by the Company exceeded minimal amounts. **BEGIN RECO CONFIDENTIAL** "

" **END RECO CONFIDENTIAL**

This shows that the New York PSC staff was no longer skeptical about hedging. It also suggests that, although regulatory concerns might have influenced Con Edison's start-up of the hedging strategy, they were soon overtaken by prudent planning considerations. However, it should be repeated that the January 2, 2001 memo refers to Con Edison New York, not to RECO. With regard to percentage coverage, the internal presentation dated January 2, 2001 (referred to above), stated: [**BEGIN RECO CONFIDENTIAL**]
"

" [**END RECO CONFIDENTIAL**]

An internal O&R presentation dated March 19, 2001outlined a hedging strategy for O&R for the summer capability period. It listed the objectives for summer requirements as "reduce price volatility," and "limit regulatory risk." An internal document (provided in response to RECO-ADR-L-53) prepared around this time, [**BEGIN RECO CONFIDENTIAL**]

[**END RECO CONFIDENTIAL**]

On April 1, 2001, Con Edison's Regulated Risk Management Committee (RRMC) approved a *Regulated Electric Energy Trading Risk Management Policy*. This policy document established the objectives and procedures for entering into financial hedges to protect full-service customers from exposure to the spot markets. The Committee's responsibilities covered both electricity and gas.

By the spring of 2001, the outlook for Summer 2001 had settled down, and on April 18, 2001, O&R'S Board of Directors approved the hedging of electricity, gas and oil prices. A memo to Con Edison's Board of Trustees from the Company's Chief Financial Officer dated April 12, 2001 had explained the subject of financial hedging and described the various kinds of hedges that were available. These included swaps, options and collars. The authorization was broad, covering just about any derivative instruments that the management might choose to acquire.

Subsequently, Con Edison management was specifically authorized from time to time to enter into hedging contracts for specific periods, up to specified limits. The Supply Department then purchased some hedges for the first time, to protect against price spikes during the forthcoming summer.

In 2001, two types of hedging instruments were utilized: swap (which is sometimes referred to as a contract for differences or 'CFD') and collar. The swap enabled O&R to lock in a fixed price. The collar established both a ceiling price and a floor price for a fixed amount of megawatts. The collar allowed for downward participation in prices to the floor price level. By utilizing more than one hedging instrument, the portfolio gave us the upside price protection as well as the inherent lowering of costs if the energy prices came in lower than the swap price. This made the energy supply portfolio more robust in the face of significant price uncertainty. (Response to RECO-ADR-L-50)

Prices moderated in the summer of 2001, compared with the previous summer. Mr. Holtman acknowledges (Direct Testimony, p. 22) that, "those lower prices did make the hedges appear uneconomic in hindsight."

On July 5, 2001, the RRMC had the first of a series of monthly meetings to review hedging strategies and procedures. The Committee formed a Policy and Procedures (2-P) Committee which would meet more frequently, e.g., weekly or every other week.

At its September 5, 2001 meeting, the RRMC reviewed the electricity price and hedging experience of the summer, and considered what lessons might be learned, in view of hedging losses suffered for the period.

The 2001/2001 hedge program was reviewed at the RRMC's November 15, 2001 meeting. There was an internal presentation on *Electricity Supply Hedging* on December 20, 2001 in which the plans for 2002 were discussed:
[**BEGIN RECO CONFIDENTIAL**]

[**END RECO CONFIDENTIAL**]
The documentary record outlined above, supplemented by our discussions with Con Edison staff, support a finding that Con Edison's Supply Department kept up to date with market conditions and devoted a considerable amount of analysis to the determination of an appropriate hedging strategy for O&R in 2001 and 2002.

As a rough range, the target percentage of load covered by hedges was [**BEGIN RECO CONFIDENTIAL**]

[**END RECO CONFIDENTIAL**]

Based on the information provided to us by the Company, we believe that its decisions regarding hedging and contracting during the August 1, 1999 through July 31, 2002 were not imprudent. In terms of the language of the Task Force Report, and based on the information we have reviewed, we believe that RECO did make "reasonable decisions about purchasing power in the deregulated market."

Chapter 10 - Cost Mitigation Efforts – Renegotiation of NUG Contracts

This Chapter discusses RECO's contracts with Non-Utility Generators ("NUGs") and the reasonableness of the Company approach to addressing above-market NUG contracts.

O&R had approximately 30 MW of NUG contracts at the August 1, 1999 start of the transition period. RECO's share of these contracts was approximately 10 MW. RECO has said that it concluded that it would not have been economic to renegotiate these contracts because they represented only 2.5 percent of RECO's total supply needs. (RECO's August 15, 2002 Response to Deferred Balances Task Force Questionnaire, at page 6)

The Company also has said that none of the owners of the NUG projects indicated any desire to be bought out and that the impact on RECO of any NUG contract renegotiation or buyout would have been small. (Response to RECO-ADR-S-88) Moreover, according to RECO, the impact of any renegotiation or buyout "most likely [would] have been negative":

> Front-loading payments to the NUGs in order to reform or terminate the agreements, then replacing that power from other markets, simply trades a stream of payments for a large near-term payment and foregoes future energy deliveries. Such a practice has questionable value. (Response to RECO-ADR-S-88)

We find the Company's explanation reasonably persuasive. Nevertheless, we would have liked to have seen some effort by the Company to talk with the NUGs about restructuring the contracts. It may have been true that RECO's 10 MW of NUG contracts represented only 2.5 percent of its supply needs at the start of the transition period and, therefore, there were other, more pressing issues that required management's attention. However, over time, the above-market NUG contracts increased the amount of deferred balances by approximately $2 million to $2.5 million per year. (Exhibit FPM-3) This was not an inconsequential amount. This amount also would have been substantially higher if, as the Company's says it anticipated in 1999, future energy market prices would be lower due to increased market liquidity and competition.

Nevertheless, we do not find that the Company's failure to attempt to renegotiate or buyout its small amount of NUG contracts was imprudent.

Chapter 11 - Quantification of Imprudence

Synapse has quantified the consequences of the Company's imprudent failure to enter into a multi-year transition power purchase agreement when it divested its electric generating assets in June 1999. This quantification compares the Company's actual monthly energy and capacity costs with what those costs would have been if O&R had entered into a three year transitional power purchase agreement for 50 percent of its anticipated requirements. To be conservative, this quantification also assumes that O&R would have had to pay approximately 20 percent more for such an extended agreement, as the Company has claimed. The results of the Synapse quantification are presented in Table 11-1 on the following page.

In addition, if O&R had entered into such a multi-year transition power purchase agreement to prudently protect the customers of RECO from energy price volatility, RECO would not have incurred the $11.594 million in hedging costs during the period August 1, 1999 through July 31, 2002. These costs also are the direct consequence of the Company's imprudence. For this reason, they also are included in the Synapse quantification of the costs resulting from the Company's imprudent failure to enter into a multi-year transition power purchase agreement when it divested its electric generating assets in June 1999 shown in Table 11-1 on the following page.

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Table 11-1
Imprudent RECO Costs During the Period
August 1, 1999 through July 31, 2002

Month	*Imprudent Energy Costs*	*Inprudent Capacity Costs*	*Imprudent Hedging Costs*	*Total Imprudent Costs*
May-00	$ 2,069,747			$ 2,069,747
Jun-00	$ 2,525,810			$ 2,525,810
Jul-00	$ 1,500,366			$ 1,500,366
Aug-00	$ 2,089,134			$ 2,089,134
Sep-00	$ 1,546,905			$ 1,546,905
Oct-00	$ 1,557,317			$ 1,557,317
Nov-00	$ 1,158,713	$ (1,073,567)		$ 85,146
Dec-00	$ 1,831,164	$ (726,406)		$ 1,104,758
Jan-01	$ 789,782	$ (725,998)		$ 63,784
Feb-01	$ 738,659	$ (723,585)		$ 15,074
Mar-01	$ 1,093,678	$ (725,107)		$ 368,571
Apr-01	$ 775,165	$ (727,888)		$ 47,277
May-01	$ 1,485,420	$ (217,605)	$ 45,000	$ 1,312,814
Jun-01	$ 1,423,260	$ 102,779	$ 1,376,000	$ 2,902,039
Jul-01	$ 1,125,682	$ (30,376)	$ 5,511,000	$ 6,606,306
Aug-01	$ 3,029,984	$ 2,916	$ 2,102,000	$ 5,134,900
Sep-01	$ 396,916	$ 131,115	$ 1,014,000	$ 1,542,031
Oct-01	$ 87,038	$ 109,940	$ 1,160,000	$ 1,356,977
Nov-01	$ 49,951	$ (609,774)	$ 2,000	$ (557,823)
Dec-01	$ (5,621)	$ (604,554)	$ 74,000	$ (536,175)
Jan-02	$ 14,641	$ (599,297)	$ 140,000	$ (444,656)
Feb-02	$ (172,786)	$ (643,345)	$ 81,000	$ (735,131)
Mar-02	$ (56,091)	$ (700,640)	$ -	$ (756,730)
Apr-02	$ 33,545	$ (801,360)	$ (4,000)	$ (771,815)
May-02	$ (200,033)	$ (810,316)	$ 1,000	$ (1,009,349)
Jun-02	$ 144,222	$ (448,390)	$ 29,000	$ (275,168)
Jul-02			$ 63,000	$ 63,000
Total	**$ 25,032,567**	**$ (9,821,458)**	**$ 11,594,000**	**$ 26,805,109**