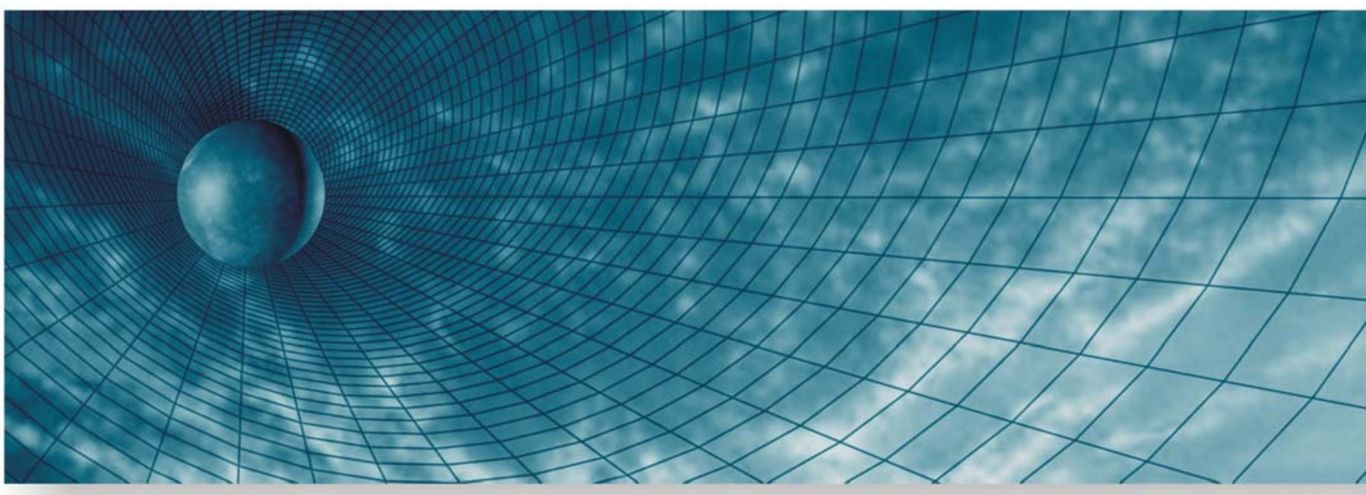
Presentation to

NYISO BSP Subcommittee

Regarding

Status Report on the Schedule 1 Evaluation Project

April 16, 2004



R·J·Rudden ASSOCIATES

OUTLINE

I. Review of Prior Meetings

II. Preliminary Results Presented at the Last BSP Meeting

III. Changes Since the Last BSP Meeting

IV. Revised Results

V. BSP Questions Received and Actions Taken

VI. Implementation Issues

VII. Next Steps

SECTION I
REVIEW OF PRIOR MEETINGS

PRIOR BSP MEETING TOPICS

Meeting 1 - December 11, 2003

- Reviewed Schedule 1 history
- Reviewed project methodology, goals and guiding principles
- Discussed MP involvement
- Presented project schedule

Meeting 2 - February 17, 2004

- Presented project status
- Discussed data collection and interview methods
- Discussed preliminary service categories
- Discussed preliminary allocation to service categories
- Received some questions and comments at the meeting

Meeting 3 (Last Meeting) – March 19, 2004

- Reviewed Service Category changes based on comments received
- Reviewed new treatment of billing and management services
- Discussed actions taken on each comment received
- Discussed preliminary billing unit selections
- Presented preliminary results of initial recommendations
- Received additional questions and comments on new recommendations

SECTION II
PRELIMINARY RESULTS PRESENTED AT THE LAST BSP MEETING

SERVICE CATEGORIES

The following revised service categories were presented at the beginning of the last BSP meeting:

1. System Reliability
2. Real-Time Operations
4. Energy/Ancillary Services Markets
5. Capacity Markets
6. TCC Markets
7. Billing & Customer Service
8. Management Services Type 1
9. Customer-Specific
10. Management Services Type 2
11. Billing Projects

SECTION III
CHANGES SINCE THE MARCH 19, 2004 BSP MEETING

Changes reflected in this report dated April 16, 2004

1. Remove Term Loan principal and interest ($12,060,000)
2. Management Services Type 1 was split into 2 subcategories - labor cost allocation and total cost allocation. Activities and costs that support personnel, and that vary with or are caused by payroll-type costs, were assigned to labor cost allocation, and allocated among the service categories based on payroll dollars (discussed below in Section V, action item 3 from March 19, 2004 meeting).
3. Proposed *Compromise Recommendation* for recovery of Energy and Ancillary Services Markets costs to 60% Load / 40% Supply (discussed below in Section V, action item 13 from March 19, 2004 meeting).
4. Proposed *Compromise Recommendation* for Energy and Ancillary Services Markets (EASM) Billing units (discussed below in Section V, action item 6 from March 19, 2004 meeting):

   The portion of EASM to be recovered from Load should have the following billing units:
   - 100% of energy market purchases excluding virtual load, plus
   - 50% of virtual load (instead of 100%), plus
   - 50% of energy bilateral withdrawals (instead of 0%).

   The portion of EASM to be recovered from Supply should have the following billing units:
   - 100% of energy market Sales excluding virtual supply, plus
   - 50% of virtual supply (instead of 100%), plus
   - No energy bilateral injections (remains 0%).
5. Proposed Capacity Market Service category billing units have been changed from a surcharge based on dollar value of transactions in the strip, monthly and deficiency auctions, to a per kW-month charge including all auction transactions (discussed below in Section V, action item 9 from March 19, 2004 meeting).
6. Proposed billing units for Transmission Congestion Contracts costs were changed to be the same as for Energy and Ancillary Services Markets, including a 60% Load / 40% Supply split (discussed below in action item 10 from March 19, 2004 meeting).
7. Assumed Net new financings to be $45 million, and were applied first, to reduce other Interest and Principal payments on 2003 Budget Facility ($13.85 million) and Hardware Financings ($3.6 million), and then the remaining $27.55 million was applied to reduce all rates proportionately (discussed below in action item 12 from March 19, 2004 meeting).
8. FERC Fees were changed from Management Services Type 2 to Management Services Type 1-for allocation (discussed below in Section V, action item 11 from March 19, 2004 meeting). Since FERC Fees were the only cost remaining in Management Services Type 2, this new change eliminates the need for the category.

As a result of items 1 and 7, the total amount to be recovered under Schedule 1 was reduced from $168.5 million to $111.4 million.

SECTION IV
REVISED RESULTS

The new results based on the changes discussed in Section III include the following tables, which have been revised to reflect the changes discussed in Section III above:

- Cost Allocations to Service Categories
- Costs and Billing Units By Service Category
- Billing Rates By Service Category and By Responsible Group
- Proposed Pro Forma and Present Rates For Load and Supply

COST ALLOCATIONS TO SERVICE CATEGORIES – APRIL 16, 2004

Group	Total	System Reliability	Real-Time Operations	Energy & Ancillary Svcs Mkts	Capacity Markets	TCC Markets	Billing and Customer Service	Mgmt Svcs Type 1 (Total Alloc.)	Mgmt Svcs Type 1 (Labor Alloc.)	Billing Projects
Finance & Compliance	100%	3%	10%	26%	3%	2%	17%	31%	2%	6%
Market Monitoring & Business Planning	100%	4%	2%	80%	1%	-	-	13%	-	-
Communications	100%	-	2%	2%	-	-	-	90%	6%	-
Operations & Reliability	100%	10%	72%	10%	-	-	-	8%	-	-
Market Services	100%	3%	4%	16%	15%	9%	1%	50%	2%	-
Executive	100%	-	-	-	-	-	-	100%	-	-
Legal / Regulatory	100%	1%	2%	2%	1%	-	4%	90%	-	-
Planning	100%	61%	1%	2%	1%	-	4%	31%	-	-
Information Technology	100%	-	25%	27%	1%	-	2%	35%	-	10%
Administration & Compliance	100%	1%	5%	6%	2%	-	1%	13%	65%	7%
Human Resources	100%	-	-	-	-	-	-	14%	86%	-
Corporate	100%	7%	10%	17%	4%	-	3%	9%	12%	10%
Category Shares Before Allocations	100%	**4%**	**17%**	**22%**	**3%**	**1%**	**4%**	**30%**	**7%**	**7%**
Category Shares After Allocations	100%	**6%**	**34%**	**53%**	**5%**	**2%**	-	-	-	-
Category Costs Before Allocations ($000)	156,422	5,577	27,021	34,192	4,195	1,434	5,779	55,886	11,460	10,877
Category Costs After Allocations ($000)	156,422	9,191	53,035	83,731	7,610	2,855	-	-	-	-
Category Costs After Net New Financing ($000)	111,422	6,706	38,445	59,948	4,158	2,165	-	-	-	-

Allocation Methods: - Billing & Customer Service allocated to Real-Time Ops, Energy & Ancillary Svc, Capacity Market and TCCs proportional to their costs.
- Billing Projects added to Energy and Ancillary Svc
- Management Svc Type 1 allocated to remaining categories based on either labor cost or total costs of services

COSTS AND BILLING UNITS BY SERVICE CATEGORY – APRIL 16, 2004

	Total	System Reliability	Real-Time Operations	Energy And Ancillary Services Markets	Capacity Markets	TCC Markets
Total Costs After Net new financings ($000)	$111,422	$6,706	$38,445	$59,948	$4,158	$2,165
Share of Total	100.0%	6.0%	34.5%	53.8%	3.7%	2.0%
Billing Units		100% Load - MWh Actual Withdrawals Including Bilaterals, Excluding Virtual Load	100% Load - MWh Actual Withdrawals Including Bilaterals, Excluding Virtual Load	60% Load- 100% Energy Market Purchases, 50% Bilaterals, 50% Virtual Load; 40% Supply- 100% Energy Market Sales, 50% Virtual Supply	50% Load- kW-months; 50% Supply- kW-months	Same as Energy and Ancillary Services
Load- Actual incl. Bilateral	40.5%	100%	100%			
Load- EASM / TCC	33.4%			60%		60%
Supply- EASM / TCC	22.3%			40%		40%
ICAP- Load	1.9%				50%	
ICAP- Supply	1.9%				50%	
Total	**100.0%**					

COSTS AND BILLING UNITS BY SERVICE CATEGORY AND BY RESPONSIBLE GROUP – APRIL 16, 2004

	Total	System Reliability	Real-Time Operations	Energy And Ancillary Services Markets	Capacity Markets	TCC Markets
Dollars To Recover ($000)						
Load- Actual incl. Bilateral	$45,151	$6,706	$38,445			
Load- EASM / TCC	$37,268			$35,969		$1,299
Supply- EASM / TCC	$24,845			$23,979		$866
ICAP- Load	$2,079				$2,079	
ICAP- Supply	$2,079				$2,079	
Total Costs	**$111,422**	**$6,706**	**$38,445**	**$59,948**	**$4,158**	**$2,165**
Billing Units						
Load- Actual incl. Bilateral	MWh	160,780,644	160,780,644			
Supply- Actual incl. Bilateral	MWh					
Load- EASM / TCC	MWh			133,323,061		133,323,061
Supply- EASM / TCC	MWh			101,831,313		101,831,313
ICAP Load / Supply	kW-months				179,641	

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BILLING RATES BY SERVICE CATEGORY AND BY RESPONSIBLE GROUP – APRIL 16, 2004

		Total	System Reliability	Real-Time Operations	Energy And Ancillary Services Markets	Capacity Markets	TCC Markets
Load- Actual incl. Bilateral	$ / MWh Withdrawn	$0.2808	$0.0417	$0.2391			
Load- EASM / TCC	$ / MWh Transacted – (Purchased, Withdrawn, Virtual)	$0.2795			$0.2698		$0.0097
Supply- EASM / TCC	$ / MWh Transacted – (Sold, Virtual)	$0.2440			$0.2355		$0.0085
ICAP Load	kW-months Purchased	$11.5736				$11.5736	
ICAP Supply	kW-months - Sold	$11.5736				$11.5736	

PROPOSED PRO FORMA AND PRESENT RATES FOR LOAD AND SUPPLY– APRIL 16, 2004

		Proposed		Present	
Load:		**$ 000**		**$ 000**	
Present Bundled				$94,709	
System Reliability		$6,706			
Real-Time Operations		38,445			
TCC Markets		1,299			
Energy and Ancillary Services Markets		35,969			
ICAP Purchases		2,079			
Total for Load		**$84,498**	**75.8%**	**$94,709**	**85.0%**
Actual MWh Withdrawals incl. Bilaterals	MWh	160,780,644		160,780,644	
Total Pro Forma Rate for Load	$ / MWh	$0.5255		$0.5891	
Supply:					
Present Bundled				$16,713	
TCC Markets		$866			
Energy and Ancillary Services Markets		23,979			
ICAP Suppliers		2,079			
Total for Supply		**$26,924**	**24.2%**	**$16,713**	**15.0%**
Actual MWh Injections incl. Bilaterals	MWh	168,987,866		168,987,866	
Total Pro Forma Rate for Supply	$ / MWh	$0.1593		$0.0989	

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SECTION V
BSP QUESTIONS RECEIVED AND ACTIONS TAKEN

ACTION ITEMS FROM MARCH 19, 2004 MEETING

The following items provide a summary of the requests made by BSP Subcommittee members during the March 19, 2004 presentation on the status of the Schedule 1 Evaluation project. The responses represent Rudden's response to each of the requests.

1. **Compare the Rudden recommendations for assigning activities to the Service Categories, with the assignments for similar activities used in the prior NYISO study, that lead to the existing rate design allocating 85% of the costs to load and 15% to supply. In particular, analyze the causes for the change in the overall effect from 85/15 to 70/30.**

   Response*:*

   The difference in the 85/15 of the prior study and the 70/30 presented by Rudden at the March 19, 2004 meeting appear to be largely driven by the allocation of the Market Support Functions (which is most similar to Rudden's Energy and Ancillary Services Markets - EASM). In the prior study, most of the costs identified as Market Support Functions were split 75% LSEs (Load) / 25% Generators (Supply). Rudden assumes the 75/25 allocation was a proposed compromise or estimate since Rudden found no quantitative basis for the split.

   In the present study, to assign responsibility and to select billing units on the basis of a cost causation, Rudden examined the activities involved in the EASM Category. While this requires judgments as to several of the activities, the range of outcomes under several sets of assumptions was 60/40 to 40/60 and, therefore, a 50/50 split was judged most appropriate. If a 75/25 split were used for EASM, the cumulative results of the allocation of all of the categories in the present study would be nearly identical to the prior study, i.e., resulting in 85/15.

2. **Compare the overall effect of the Rudden recommendations for Schedule 1 on Load vs. Supply, to the other ISOs.**

   Response*:*

   The following tables show the approximate shares of total costs paid by Load and Supply in each of the four ISOs with unbundled cost recovery.

	Load	Supply
NYISO (3/19/04 Proposal, as Revised 4/1/04)	72.3%	27.7%
NYISO (4/16/04 Proposal, BEFORE Net New financings- See item 12)	75.4%	24.6%
NYISO (4/16/04 Proposal, AFTER Net New financings- See item 12)	75.8%	24.2%
California ISO	89.1%	10.9%
ISO New England	67.9%	32.1%
PJM	79.1%	20.9%

3. **Consider the allocation of some of the departments in the Management Services Type 1 costs (e.g., the Human Resources Department) based on labor dollars versus total dollars.**

Response*:*

Rudden agrees that this refinement would better reflect cost causation. Therefore, Management Services Type 1 was split into 2 subcategories - Labor Cost Allocation and Total Cost Allocation. Approximately $11.5 million of activities and costs that support personnel, and that vary with or are caused by payroll-type costs, were put into Management Services Type 1- Labor Cost Allocation, and allocated among the Service Categories based on payroll dollars.

4. **Review the possibility of moving external legal services, auditing and market monitoring to Management Services Type 2 (MS2). Consider whether the full MS2 category should be allocated 50% to load and 50% to supply.**

Response*:*

MS2 is used for costs requiring special allocation. Costs that support the "support the activities required for all of the Service Categories" are similar to Administrative & General (A&G) costs in a typical utility cost of service study, and are included in Management Services Type 1 (MS1) and allocated in proportion to the Service Categories they support. To assign cost responsibility 50/50 for these costs eliminates the "functionalization" step for these costs, which is an important part of the study.

Auditing costs clearly "support the activities required for all of the Service Categories" and should be included in MS1 and allocated as stated above.

External legal costs could be allocated among Service Categories, but this would require a special study, which would be time-consuming and costly. In the absence of such a study, allocation based on other activities is the preferred approach.

Market Monitoring costs clearly are aligned with the Service Categories of Energy and Ancillary Services Markets, Capacity Markets and TCC Markets, and have been included in those Service Categories.

5. **Provide a list of "A" Projects, and a list of billing projects, and how they were allocated in the Rudden recommendations.**

<u>**Response**</u>*:*

The list of "A" Projects, including recommended allocations, was provided to the NYISO for distribution to the BSP.

6. **Review the reasoning and potential market impacts resulting from the following recommendations for recovering costs for the Energy and Ancillary Services Markets (EASM) Service Category:**

   - **Excluding bilateral contracts, as the exclusion of bilaterals could result in inducing market participants to pursue physical bilateral arrangements rather than to participate in the NYISO energy markets.**
   - **Including virtual load and virtual supply, as the allocation of significant charges to virtual bids might interfere with the converging of the NYISO day-ahead and real-time markets.**

<u>**Response**</u>*:*

Bilaterals were "excluded" and virtual bids were "included" based on cost causation. However, as Rudden has noted, one of the criteria for rate design is to "Minimize impact on market behavior and on NYISO operations."

Bilateral Arrangements

Rudden agrees with the implicit assumption, regarding bilateral arrangements, that changes in the number or MWh volume of market transactions do not affect NYISO costs, and that the cost per NYISO energy market transaction will increase if more MWh are supplied under bilateral arrangements and fewer through NYISO energy market transactions.

However, it is not known if avoiding a cost of approximately $0.39 per MWh will cause a significant shift to bilateral arrangements, although what starts as a small shift could snowball into a large shift that could make it too costly to participate in NYISO energy market transactions.

Reasons to Exclude Bilaterals: A shift from NYISO market transactions to bilaterals may help to stabilize prices over the long term. While a less liquid market could cause apparent price spikes, fewer MWh would actually be impacted, and NYISO market mitigation procedures would protect consumers. Similarly, higher volumes of NYISO market transactions cause greater price uncertainty and, over the long term, probably cause higher NYISO costs. Therefore, it is desirable to have an incentive for the use of bilateral arrangements and a disincentive for over-reliance on, or exclusive use of, the NYISO energy markets.

Reasons to Include Bilaterals: The lower the cost of NYISO energy market transactions, the greater the volume of opportunistic exports and wheel-throughs, which helps the economy (by making low-cost energy available) and helps to reduce costs to NYISO load by increasing the denominator for cost recovery. However, the decision to spread these costs over a wider base, rather than collect the costs only from the parties that benefit from the ability to export and wheel-through, is a policy decision.

In addition, EASM includes the costs of administering the ancillary services markets, including items such as spinning reserves that allow load to enter into bilateral arrangements with the assurance that a backup supply exists if the bilateral counterparty fails. This is a tangible benefit to parties that are considering bilateral arrangements, although it is difficult to quantify.

Virtual Markets

Rudden agrees that a cost of approximately $0.39 per MWh for virtual market transactions could reduce the liquidity of the virtual markets, which would work against the goal of helping prices to converge between the NYISO day-ahead and real-time markets.

If the goal of price convergence between the day-ahead and real-time markets is achieved, the beneficiaries of virtual bids are not only those parties that engage in them, but all parties that use the NYISO energy markets. However, a more direct benefit is received by those that use virtual markets, and they should pay a greater share of the costs, as should those that use the virtual markets without using the NYISO energy markets.

Conclusion and Recommendation

Bilaterals: Rudden believes that bilaterals should not bear the full costs of the EASM Service Category, because they do not use all of the services, but should pay a portion of the costs. A cost of approximately $0.39 per MWh to use the NYISO energy markets may be high enough to cause a shift towards bilaterals that, if continued, could hurt market liquidity. However, some share of the costs being allocated to bilaterals is justified.

Virtual Markets: Rudden also believes that virtual market transactions should pay some costs, but not a full share, to recognize that a full share may discourage use of the virtual markets.

Therefore, the following compromise recommendation is proposed, subject to review by NYSIO, market experts and market participants:

Compromise Recommendation:

The portion of EASM to be recovered from Load should have the following billing units:

- 100% of energy market purchases excluding virtual load, plus
- 50% of virtual load (instead of 100%), plus
- 50% of energy bilateral withdrawals (instead of 0%).

The portion of EASM to be recovered from supply should have the following billing units:

- 100% of energy market sales excluding virtual supply, plus
- 50% of virtual supply (instead of 100%), plus
- No energy bilateral injections (remains 0%).

7. **The NYISO Vice Presidents should review Rudden's recommendations for the Schedule 1 allocations, in particular the impact of the recommendations for bilaterals and virtual trading.**

<u>Response</u>*:*

NYISO has presented Rudden's March 19, 2004 recommendations to the NYISO vice presidents. No substantiative issues or changes were identified at this time.

8. Review the possibility of using MW to allocate the System Reliability Service Category rather than MWh.

Response*:*

It is believed that MWh is a better billing unit for the System Reliability Service Category than MW because:

- The costs are caused by the need to maintain reliability hour-by-hour, in addition to the peak.
- MWh is more stable and predictable from year-to-year than MW.
- An MWh billing unit could encourage users to shift usage away from the system peak. While this is desirable, the costs of providing this service would not change. This is unlike transmission system costs, where a shift in usage away from the peak does help to reduce costs.
- This would be the only service category with MW billing units, and this would create an additional cost for implementation and administration.

9. Review the recommendations for: a) collecting Capacity Market Service Category costs through a surcharge on the ICAP market transactions, b) excluding spot auction excess transactions, and c) excluding self-supplied ICAP from the charges.

Response*:*

Surcharge Mechanism vs. Per kW-month or Per kW: To reflect cost causation more closely, and to avoid a "regressive" tax (i.e., where those LSEs that pay the most for ICAP would also pay the most for the Capacity Market Service Category), Rudden agrees that these costs should not be recovered using a surcharge based on transaction value. The prior concerns that recovering the costs of this category on a per MW or a per MW-month could be a significant portion of the transaction value for some transactions, was found, on further analysis of the data, to have only a minor impact. For only 16.1% of transactions, measured by value, would the Capacity Market Service Category cost to Load be 1% of transaction value or greater, and the same is true of Supply if costs are split 50/50 as proposed. If desired, a maximum charge per transaction could be developed (based on a percent of transaction cost), with the under-collection recovered from other ratepayers in the service category.

Neither kW-months nor kW are closely correlated to cost causation, due to the fact that almost all of the costs incurred in running the capacity markets are fixed. However, kW-months are more closely related to benefits received than kW, therefore, a charge based on kW-months is recommended to recover Capacity Market Service Category costs.

Spot Auction Excess Transactions: Spot Auction Excess Transactions have been included in the denominator.

Self-Supplied ICAP: LSEs and ICAP suppliers that do not participate in the auctions should not have responsibility for the costs of the auctions. While excluding self-supplied ICAP from the Billing Units could reduce the number of auction participants and increase the cost per transaction, including self-supplied ICAP would fail to differentiate between those that use the service and those that do not. It is recommended that self-supplied ICAP be excluded from Billing Units, but that the effects be monitored closely, and the Billing Units for this Service Category be changed if the effects are determined to be adverse.

Summary: The proposed Capacity Market Service Category billing units have been changed from a surcharge based on dollar value of transactions in the strip, monthly and deficiency auctions, to a Per kW-month charge including all auction transactions.

10. Review the proposed treatment of combining the Transmission Congestion Contracts (TCC) Market with the Real-Time Operations Service Category. Consider combining the TCC Services Category with Energy and Ancillary Services Markets Service Category, reflecting the view that these contracts provide financial hedges for transactions in the energy markets. In addition, consider the possibility that the TCC costs may grow with the potential influx of merchant transmission, and the impact this would have on the proposed rate design.

Response*:*

Since these contracts provide financial hedges for transactions in the energy market, the billing units for TCC were changed to be the same as for Energy and Ancillary Services Markets, including a 60% Load / 40% Supply split.

Further, while it is possible that a large amount of merchant transmission will occur and will cause large costs to be incurred by the NYISO to develop the TCC market, in the event that occurs, the NYISO would have to re-evaluate its rate design for these costs. However, the same is true of any change in market operations or other aspect of NYISO business. It is expected that the NYISO will periodically review its Schedule 1 rate design to ensure that it remains fair and reasonable.

11. In the analysis of present charges, correct the treatment of the FERC fees to reflect the allocation method used in the existing rate design. Consider an alternative allocation that reflects the view that FERC activities govern, and the FERC fee is caused by and benefits both load and supply.

Response*:*

The allocation of FERC Fees in the Present rate design was changed to add the fees to the Management Services Type 1 costs for allocation to the other service categories. Rudden agrees that while the FERC's jurisdiction over NYISO was originally primarily a function of NYISO's role as a transmission provider, the relationship between the NYISO and the FERC has evolved and now touches every part of NYISO operations. Therefore, Rudden recommends including FERC Fees in Management Services Type 1- Total Allocation

12. Develop a recommendation on how to treat the actual net costs, after any financing, versus the gross costs, prior to financing, that are currently used in the analysis.

Response*:*

Based on discussions with the NYISO, new financings in any year are sized to approximate the amount spent on projects that will benefit future periods. However, there is no specific allocation of cash to those projects. In addition, the need for financing is based on the desire to stabilize rates, and it is assumed that in future periods less cash will be required for projects that will benefit future periods and, thus, (if revenue is stable) cash will be available to repay financings.

It is assumed that Net new financing in 2004 will be $45 million, reducing the amount to be recovered under Schedule 1 from $156.4 million (2004 Budget less existing Term Loan) to $111.4 million. "Net new financing" means the proceeds of any new financings less current year payments on the new financings.

Listed below are the options identified for treating the 2004 Net new financing in the development of Schedule 1 rates. In order to apply in full the Net new financings, it may be necessary to select more than one of the options identified below.

A. Reduce all rates proportionately. For example, if the pre-financing cost is $100 million and the NYISO plans $20 million of Net new financing, all rates are reduced by 20%.

B. Apply the net new financing to reduce Project costs ($13.1 million) and Billing Project costs ($17.4 million), which aggregate $30.5 million. If this option is selected, one or more other options also will be selected for the remaining $14.5 million of Net new financing.

C. Apply the Net new financing to reduce other Interest and Principal payments on 2003 Budget Facility ($13.85 million) and Hardware Financings ($3.6 million), which aggregate $17.45 million. If this option is selected, one or more other options also will be selected for the remaining $27.55 million of Net new financing.

D. Apply the Net new financing to reduce the Management Services Type 1 costs, which aggregate $56.3 million.

Option B is supported by the fact that new financings are sized to approximate the amount spent on projects that will benefit future periods. However, there is no specific allocation of cash to projects. In addition, choosing this option would mean that repayments of the new financings, when included in future years, should be recovered in the same manner as the benefits received from the original borrowings. This would require additional record keeping to account for the financing and repayments for each project, in order to align the benefits (i.e., lower rates in the year debt is issued) with the costs (i.e., higher rates when debt is repaid).

Options A and C are supported by the facts that Net new financings are used for general NYISO purposes and not for specific projects, and are based on the desire to stabilize rates. In addition, when repayments of the new financings are included in future years, the amounts could be recovered using a proportionate increase in rates. Between option A and option C, option C more closely reflects the NYISO purpose of stabilizing rates and looking at cash flows on an aggregate basis.

Option D does not reflect any of the NYISO's purposes in securing new financings.

In conclusion, Rudden recommends that Net new financings be applied using option C and option A, as follows:

- Apply the Net new financing to reduce other Interest and Principal payments on 2003 Budget Facility ($13.85 million) and Hardware Financings ($3.6 million), which aggregate $17.45 million.
- Use the remaining $27.55 million of Net new financing to reduce all rates proportionately.

13. Review why ancillary services are included with energy markets, when these costs are necessitated only due to the manner in which real-time operations must be run and, therefore, should be included in the Real-Time Operations Service Category.

Response*:*

Rudden agrees that unlike energy, most ancillary services (AS) cannot be obtained by an individual LSE though bilateral arrangements or self-supply (e.g., spinning reserves). For these AS, only the NYISO can obtain the services, which are required for reliability purposes and are caused by users (i.e., Load). The NYISO has elected to obtain these AS through market operations and not through contracts, so suppliers are needed for a functioning market AS and should be encouraged to participate. It would more properly reflect cost causation if the costs of running the AS markets were assigned to Load and not to Supply.

It was not possible to isolate the costs of running the AS markets in order to include them in real-time operations, due to the time and budget and the information available. Further, a separate billing unit for the costs of running the AS markets would add significant cost and complexity to implementation of unbundled rates.

Therefore, the following compromise recommendation is proposed, subject to review by NYSIO, market experts and market participants:

Compromise Recommendation:

To reflect that the portion of EASM costs attributable to AS markets should be recovered from Load, the costs of the EASM Service Category should be recovered 60% from Load / 40% from Supply, instead of 50/50.

14. The NYISO should ask its markets expert to review Rudden's recommendations for the Schedule 1 allocations.

Response:

NYISO has agreed to have David Patton review the latest Rudden recommendation during the second half of April.

SECTION VI
IMPLEMENTATION ISSUES

1. **<u>Start Date for Unbundled Rates</u>**
   - **A.** This unbundling project uses 2004 Budget costs.
   - **B.** <u>Full Year Rates</u> - The full year rates developed for 2004 are used commencing on the start date. This is easy to do.
   - **C.** <u>Pro Rata Part Year Rates</u> - The rates are recomputed using: Numerator- pro rata share of annual costs; denominator- estimated Billing Units for the balance of the year. This is also easy to do.
   - **D.** <u>Estimated Part Year Rates</u> - The rates are recomputed using: Numerator- estimated costs for the balance of the year; Denominator- estimated Billing Units for the balance of the year. If the numerator is developed by category, this will be difficult to do.
   - **E.** In either case, the True-Up would use actual costs commencing on the start date.
   - **F.** Start date must allow for any billing system changes necessary to accommodate new rate design

   Recommendation: Assuming the final recommended rate design results in only a change to the current allocation percentage (i.e. changing the 85/15 to a new ratio), the BSP should target for an MC approval by June 30, 2004, a FERC filing by August 31, 2004 and new rates in effect by January 1, 2005.

2. **<u>Annual vs. Monthly Rate-Setting</u>**
   - **A.** <u>Annual</u> - Total annual dollars for each category are divided by estimated billing units. Provides rate certainty for customers, but variable revenues for NYISO as billing units vary each month.
   - **B.** <u>Monthly</u> - Each month, divide 1/12 of annual dollars for each category by estimated monthly billing units. Provides level cash receipts to the NYISO, but creates variable rates for customers.
   - **C.** Current NYISO practice is to develop monthly rates, but to stabilize at 74 cents per MWH, which has the same effect as annual rates.

   Recommendation: Set rates based on an annual basis.

3. **<u>True-Ups - Annual vs. Monthly vs. Retrospective</u>**
   - **A.** Under or Over collections arise from differences in actual costs compared to budget costs, and actual billing units compared to budget Billing Units
   - **B.** <u>Annual</u> - Differences at the end of one year are included in the amount recoverable for the next year. Provides natural smoothing. However, as members and their usage change, causes intergenerational shifts, but these amounts usually are not significant.

- **C.** Monthly - Differences in each month are included in the next month's revenue requirement. Must be used with Monthly Rate-Setting; if used with Annual Rate-Setting, rate stability is lost. Can cause very volatile rates. Cost shifts arising from changes in monthly usage are considered more significant than intergenerational shifts arising from Annual true-ups.
- **D.** Retrospective - Invoices are adjusted retrospectively to reflect actual costs and actual Billing Units. Requires assignment of actual costs among categories using Actual By Category (very difficult- discussed below) or Allocated By Category (not as precise- discussed below). Eliminates cost shifts. Compromises rate stability, but if combined with Annual Rate-Setting, customers get rate stability for a year and natural smoothing can reduce large true-ups.

> **Recommendation:** True-up rates annually with the methods currently used at NYISO.

4. True-Ups - Actual By Category vs. Allocated By Category vs. Pooled

- **A.** Under or over collections can be computed, and true-ups can be assessed, either by category using actual data, by category using allocated data or in the aggregate.
- **B.** Actual By Category - Actual costs for each category are computed using the same method that was used originally to set the rates. Under or over amounts are collected from the categories from which they arose, using annual, monthly or retrospective true-ups (discussed above). Requires a great deal of work to allocate costs. Small categories can have very large true-ups.
- **C.** Allocated By Category - Actual costs are allocated among categories using the same ratios as originally derived to set the rates. Much easier to calculate than actual by category but not as precise.
- **D.** Pooled - The entire under or over collection is either allocated to the single largest category or collected on an MWh basis. If True-Ups are small, this saves effort and has minimal cost shifts.

> **Recommendation:** True-up the rates based on allocation to the categories in the same ratios as derived in the new rates.

5. Future Years- Redo Study vs. Update Costs

- **A.** Redo Study Annually - This would be time-consuming, and implementing changes could be controversial. This is the approach that ISO-New England uses, but it is very time-consuming.
- **B.** Update Costs - This would involve applying the allocation percentages from the Unbundling Study to the updated budget costs each year. While easy to implement, changes in activity levels could cause doubt as to whether the results are applicable each year.
- **C.** Determine Life of Study - The rate design determined by this current study cannot remain unreviewed indefinitely. A time frame should be established to review the rate design

(categories descriptions, cost allocations, billing determinants) and require an update or determine whether an update is warranted.. This Study life could be one year as indicated in 6a. above or a longer period such as 3 or 5 years.

D. Establish annual review - To assess whether new service categories need to be established or existing ones eliminated or combined.

E. Determine treatment of large items that are known to be ending after 2004, such as Start-Up Cost amortization and possibly Billing System projects.

Recommendation: Maintain rates design for three years. Redo the study every three years and let MC decide whether filing and implementing a new rate design is warranted based on results of the three-year study.

6. OATT and MST vs. Combining all charges in the OATT

A. MST was created to accommodate billing to Generators, who do not take service under the OATT as currently written

B. Reflecting all service categories in both tariffs is the easiest approach

C. Another alternative is amending the OATT so that it applies to Generators

D. Determine treatment of Start-Up costs, which are specifically assigned 50% to OATT and 50% to MST in the current arrangement.

Recommendation: Further analysis is required to form a recommendation on this issue.

SECTION VIII
NEXT STEPS

- Address comments from this meeting
- Review individual MP impacts
- Analyze implementation issues and form recommendations
- Create draft report to communicate study