

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

California Independent System Operator	)	Docket No.	ER04-____-000
Corporation	)		
	)		
	)		

GRID MANAGEMENT CHARGE

VOLUME VIII OF IX

- Exhibit Numbers ISO-266 through ISO-334

Access Database 04-29-03.txt

From: lkirsch@svn.net
Sent: Tuesday, April 29, 2003 9:52 AM
To: McGuffin, Mike
Cc: Arikawa, Ben; Leiber, Phil; bbborissov@lrca.com;
rchemphill@lrca.com
Subject: Access Database

Mike:

As we discussed yesterday, you are burning a CD that will have SC-by-SC data for each 10-minute interval of the period 9/1/01 through 8/31/02. The data for each SC includes: a) "Masked Company" and "Masked ID" identifiers that match those used by the ISO in its bill impact analysis; and b) uninstructed deviations for each interval.

The first thing that we (Christensen Associates) will do with the dataset is make sure that its data matches the billing determinants used by the ISO in its bill impact analysis. For each SC, we will specifically look at the sum of the absolute uninstructed deviations over the twelve months, and at the maximum absolute uninstructed deviations over the twelve months.

Please send us the CD by overnight mail so that it reaches us on Wednesday. The person to send it to is: Blagoy Borissov / Christensen Associates / 4610 University Avenue, Suite 700 / Madison, WI 53705-2164. His phone number is (608) 231-2266.

If you have any questions or concerns, please give me a call at (415) 663-8608.

Thanks for your help.

Laurence

Laurence D. Kirsch	
Laurits R. Christensen Associates, Inc.	email:
LKIRSCH@LRCA.COM	
4610 University Avenue, Suite 700	voice: (415) 663-8608
Madison, WI 53705-2164	fax: (415)
663-8818	

Please visit our website at WWW.LRCA.COM

RE Net uninstructed energy database 05-02-03.txt

From: McGuffin, Mike

Sent: Friday, May 02, 2003 10:18 AM

To: Arikawa, Ben; Hemphill, Ross; Kirsch, Laurence; Pritchard, Jan

Cc: Leiber, Phil; Morrison, Stephen; Le Vine, Debi

Subject: RE: Net uninstructed energy database

I apologize for the ever changing Uninstructed Energy numbers. We are looking into the differences and trying to figure out why the queries are producing different results. As Ben mentioned, the differences may be due to rounding. If I come up with anything significant, I'll update the group.

Mike

-----Original Message-----

From: Arikawa, Ben

Sent: Friday, May 02, 2003 6:45 AM

To: Hemphill, Ross; Kirsch, Laurence; Pritchard, Jan

Cc: Leiber, Phil; Morrison, Stephen; McGuffin, Mike; Le Vine, Debi

Subject: Net uninstructed energy database

Ross, Laurence and Jan,

The database of uninstructed energy by masked ID and company ID will go out to Ross this afternoon subject to the NDA, etc. Sorry for the delay, but I needed to map the SC IDs to the masked and company IDs and I wanted to check the data for consistency with what we sent out earlier.

I did not check all IDs, but there are differences in the data from what we sent out earlier. Mike McGuffin tells me that these differences may be due to rounding as the data is being compiled. The total is still approximately 16.5 million MWWhs.

Note: the attached documents are circulated by the sender solely for the express purpose of informing discussion. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender, author or the California ISO.

Ben Arikawa

RE Net uninstructed energy database 05-02-03.txt
Senior Financial Analyst
California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630

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fax: (916) 351-2259

email: barikawa@caiso.com



2004 GMC Rate Structure Project Briefing

To: Participants in 2004 GMC Rate Structure Project
From: Ben T. Arikawa, Senior Financial Analyst
Date: May 5, 2003
Re: 2004 GMC Rate Structure Project related items

This Briefing contains:

- Availability of deviation data requested by MID;
- Availability of confidential documents and data;
- May 7, 2003 conference call information;
- Request for RSVPs for the May 12th meeting in Folsom; and,
- Additional meetings scheduled.

Availability of deviation data

MID requested 12 months (September 2001 to August 2002) of deviation data at the SC ID level with coding corresponding to that used in the bill impact analysis presented during the confidential portion of the April 28, 2003 2004 GMC Rate Structure Project meeting. This data has been provided to MID and is also available to other entities. If you would like a copy of this data, please e-mail me with your request. A CD containing the data will be sent to you.

You must have signed the Non-Disclosure Certificate and your organization must have executed the Confidentiality Agreement in order for this data to be released to you.

Availability of confidential documents and data

Attached to this e-mail message distributing this briefing is a listing of data provided under the Confidentiality Agreement. If you wish a copy of the data or documents, please let me know.

May 7, 2003 conference call information

A conference call has been scheduled for May 7, 2003 from 1:30 pm to 3:30 pm. As was discussed during the April 28th GMC meeting, the purpose of this conference call is to discuss options for the recovery of customer service costs. The ISO has requested that participants present written conceptual options for the recovery of customer service costs.

Created By: Ben Arikawa

LST UPDT: 05/05/03

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Conference call information (Please note the new passcode):

Exh. No. ISO- 268, Page 2 of 2

Date and time – Wednesday May 7, 2003, 1:30 to 3:30

Call in number – 888-788-6681

Passcode – 98563

Request for RSVPs for the May 12th meeting in Folsom

The May 12th meeting will be held in Folsom at the Lake Natoma Inn. All large conference rooms at the ISO have been booked for other meetings, so the May 12th meeting will be held at the Lake Natoma Inn in Folsom. This URL gives directions to the Inn:

<http://www.lakenatomainn.com/mapDirections.stm> . Written directions will be provided along with the agenda later this week.

Due to the need to reserve adequate space and food, we request that you RSVP for this meeting by noon, Wednesday, May 7, 2003. Please RSVP to Michelle Gamble, mgamble@caiso.com, (916) 351-2118, as soon as possible.

During a portion of this meeting, confidential data will be considered. Only individuals that have signed the Non-Disclosure Certificate may attend the confidential session. A separate call in number will also be provided.

We will make every attempt to have an agenda and meeting materials available by COB Thursday, May 8, 2003.

Additional meetings scheduled

As noted in an e-mail sent out yesterday, additional meetings and conference calls have been scheduled. In addition to the May 7th conference call and the May 12th meeting, these are:

Conference call, May 19 10:00 – 12:00 (tentative)

Meeting in Folsom, June 4, 2003 9:00 – 3:00

If you have any questions about any of the information contained in this memorandum or about the process, please do not hesitate to contact:

Phil Leiber pleiber@caiso.com (916) 351-2168	Ben Arikawa barikawa@caiso.com (916) 608-5958
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Questions About Billing Determinant Data 05-06-03.txt
From: lkirsch@svn.net
Sent: Tuesday, May 06, 2003 2:50 PM
To: Arikawa, Ben
Cc: McGuffin, Mike; Leiber, Phil; Pritchard, Jan; Neal, Sean;
rchemphill@lrca.com
Subject: Questions About Billing Determinant Data

Ben:

In examining bill impacts, I ed Grid Load Data Gross Load, for the discrepancies in the billing determinant data for Masked SC ID #31. The importance of the apparent discrepancies is that they lead to very large bill impacts for both the ISO and MID proposals. I also wonder if similar discrepancies appear in the billing determinant data for other SCs.

According to the data in the ISO-prepared spreadsheet entitled "GMC Analysis Tool- 2004-MID-masked.xls" (dated about 4/25/03), the annual billing determinant data for ID #31 include load (gross?) of 125 MWh, monthly peak loads that sum to 50 MW, trades of 48 MWh, energy imbalances that sum to 45 MWh for the year and peak at 50 MW, and trades of 9 MWh per year. Aside from rounding, that describes a small SC with intermittent activity. But the inter-regional transfers are somehow 7,287 MWh, and (here's the kicker) there are a whopping 69,777 schedules. How is it possible for this tiny SC to have such high inter-regional flows and schedules? The resulting scheduling charge of \$104,477 is the main source of the 5000% increase in this SC's bill relative to its total bill of \$2,389 under the old GMC.

Is there a problem with the data, or is there something that I misunderstand?

Laurence

Questions About Billing Determinant Data 05-06-03.txt

Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.
e-mail: LKIRSCH@LRCA.COM
voice: (415) 663-8608
fax: (415) 663-8818

Please visit our website at WWW.LRCA.COM

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System Operator

Agenda

2004 GMC Rate Structure Project
Wednesday, May 7, 2003
Location: California ISO, Folsom
1:30 a.m. to 3:30 p.m.

Conference Call-in #1-888-788-6681 Passcode: 98563

1. Introductions/roll call
2. Review of options submitted to ISO
3. Discussion of options

Created by: Ben Arikawa

CAISO

LSUPDT: 05/05/03

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Proposed Agenda
2004 GMC Rate Structure Project
Wednesday, May 7, 2003
Location: California ISO, Folsom
1:30 a.m. to 3:30 p.m.

Conference Call-in #1-888-788-6681 Passcode: 98563

1. Introductions/roll call
2. Review of options submitted to ISO
3. Discussion of options

Created by: Ben Arikawa

CAISO

LSUPDT: 05/08/03

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See list of attendees attached below.

CDWR started the discussion with its concerns about whether activities were properly functionalized in the Customer Service function. CDWR advocated assigning costs to the other functions to reduce cross subsidization. CDWR argued that these costs should be allocated to market functions to reflect "cost causation."

MID similarly argued the need for proper assignment of costs. MID also mentioned that the rate design should also provide incentives for the ISO to reduce costs.

David Cohen asked if the ISO had considered billing GMC directly to commodities, such as Ancillary Services. There was some discussion of similarities between the MID, CDWR and David Cohen arguments.

CDWR asked about documents and data showing the cost assignments and the reasoning behind the assignments. The ISO replied that it had provided these prior to the April 11th meeting and that they had been posted to the confidential discussion board. Usernames and passwords had been distributed.

Based on the comments during this conference call, the discussions between the ISO and various participants and the need for a viable form of cost recovery, the ISO had revised its initial proposal with respect to the Customer Service function. The ISO proposed that a monthly fee of about \$500 or an annual fee of \$6,000 be assessed on each SC ID.

This prompted a discussion of the number of SCs vs. the number of SC IDs and if there was a cost basis for the \$500 monthly fee. The ISO pointed out that there was a cost basis and it was possible to justify an even greater charge than the \$500. This amount was chosen as an amount that would recover some costs but not be so high as to drive SCs away from the ISO. This amount was also similar to the amounts that other ISOs assess in an annual fee.

Most parties reserved judgment on this fee until, at least, the May 12th meeting.

The ISO proposed that the remaining costs would be recovered using the billing determinants of the other functions. The ISO still believes that the Customer Service function is a proper functionalization and that the traditional method for recovery of Customer Service costs is a fixed charge. However, due to the impact of such a charge, and the lack of a viable, single billing determinant, the ISO was willing to use volumetric determinants. The ISO also thought that this method would mitigate some of the concerns of the participants.

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CDWR asked if the ISO would be able to provide some indicative costs and rates using this approach. The ISO did not commit to providing results, but would attempt to provide something if time permitted.

David Cohen asked if there would be some discussion of the recent FERC Order in the 2001 GMC proceeding. The ISO mentioned that there would be some information distributed soon concerning a May 12th lunchtime conference call with the parties to the Settlement. David also asked if the ISO would consider delaying the Board vote on the new GMC rate structure given that ISO personnel would be tied up working on compliance filings. The ISO stated that given the constraints on the Budget timeline, a delay would require deferral of the implementation of a new GMC structure until next year.

List of Callers

Last Name	First	Company	Telephone	E-mail Address	phone
Aoki	Rod	CAC	(415) 421-4143	rsa@a-klaw.com	x
Arikawa	Ben	ISO	(916) 608-5958	barikawa@caiso.com	x
Bonaly	David	CDWR	(916) 653-6241		x
Bray	Peter	PG&E			x
Brommer	Mike	TID	(209) 883-8320	mtbrommer@tid.org	x
Cogdill	Jan	ISO			x
Cohen	David	Navigant Consulting	(503) 708-7852	dcohen@navigantconsulting.com	x
Hansen	Bert	SCE	(626) 302-3649	berton.hansen@sce.com	x
Lam	Tony	EOB	(916) 322-8632	tlam@eob.ca.gov	x
Leiber	Phil	ISO	(916) 351-2168	pleiber@caiso.com	x
McGuffin	Mike	ISO	(916) 608-5753	mmcguffin@caiso.com	x
Menzel	Erik	PG&E	(415) 973-4417	exm0@pge.com	x
Mi	JingChao	CDWR	(916) 653-1095	jmi@water.ca.gov	x
Neal	Sean	MID			x
Peterson	Mike	ISO	(916) 608-5896	mpeterson@caiso.com	x
Sandino	David	CDWR	(916) 653-5129	dsandino@water.ca.gov	x
Springer	John	ISO		jspringer@caiso.com	x
Terry	Lee	CDWR	(916) 654-3327	lterry@water.ca.gov	x
Timson	David	ISO		dtimson@caiso.com	x
Walz	Edna	CDWR	(916) 324-1720	ewalz@doj.ca.gov	x
Withrow	David	ISO	(916) 608-7134	dwithrow@caiso.com	x
Yakin	Dale	PG&E	(415) 973-1752	dgy4@pge.com	x
Yap	Catherine	Barkovich and Yap			x

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RE Questions About Billing Determinant Data 05-07-03.txt
From: Leiber, Phil
Sent: Wednesday, May 07, 2003 6:39 PM
To: 'lkirsch@svn.net'
Cc: McGuffin, Mike; Pritchard, Jan; Neal, Sean; rchemphill@lrca.com; Arikawa, Ben
Subject: RE: Questions About Billing Determinant Data

Do you mean SC id 231?

This is an SC with a high amount of interSC trades, and with load in only one month 9/2001 for 125MWh.

Under the current 3 bucket GMC structure, someone who only does interSC trades pays nothing.

With a scheduling charge that assesses on load, exports, imports, generation, interSC trades, they would pay.

Hence the large increase 5000%. If it weren't for the small amount of load they had in 9/2001, their GMC under the current structure would have been zero, and the % increase would have been infinite!

I haven't studied this in-depth, but that's my quick conclusion.

-----Original Message-----

From: lkirsch@svn.net [mailto:lkirsch@svn.net]
Sent: Tuesday, May 06, 2003 2:50 PM
To: Arikawa, Ben
Cc: McGuffin, Mike; Leiber, Phil; Pritchard, Jan; Neal, Sean; rchemphill@lrca.com
Subject: Questions About Billing Determinant Data

Ben:

In examining bill impacts, I have found what appear to be strange discrepancies in the billing determinant data for Masked SC ID #31. The importance of the apparent discrepancies is that they lead to very

RE Questions About Billing Determinant Data 05-07-03.txt
large bill impacts for both the ISO and MID proposals. I also wonder if
similar discrepancies appear in the billing determinant data for other
SCs.

According to the data in the ISO-prepared spreadsheet entitled "GMC
Analysis Tool- 2004-MID-masked.xls" (dated about 4/25/03), the annual
billing determinant data for ID #31 include load (gross?) of 125 MWh,
monthly peak loads that sum to 50 MW, trades of 48 MWh, energy
imbalances that sum to 45 MWh for the year and peak at 50 MW, and
trades of 9 MWh per year. Aside from rounding, that describes a small
SC with intermittent activity. But the inter-regional transfers are
somehow 7,287 MWh, and (here's the kicker) there are a whopping 69,777
schedules. How is it possible for this tiny SC to have such high
inter-regional flows and schedules? The resulting scheduling charge of
\$104,477 is the main source of the 5000% increase in this SC's bill
relative to its total bill of \$2,389 under the old GMC.

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Laurence

Laurence D. Kirsch
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Please visit our website at WWW.LRCA.COM



CALIFORNIA ISO

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System Operator

Status Report: Grid Management Charge

May 8, 2003
Market Issues Forum

Ben T. Arikawa
Senior Financial Analyst
barikawa@caiso.com
(916) 608-5958

Exh. No. ISO- 273, Page 1 of 16



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Topics

- FERC Order in ER01-313-000, *et.al.*
- 2004 GMC Rate Structure Project
 - Purpose of Project
 - Project Materials
 - Meetings
 - Participants
 - Alternative Proposals
 - Next steps



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FERC Order in ER01-313-000

- Issued May 2, 2003
(<http://www1.caiso.com/docs/2003/05/05/2003050515021221884.pdf>)
- Affirms much of the Initial Decision
- Exceptions
 - Demand charge on entities with behind the meter generation (greater than 50 percent capacity factor)
 - Refund of \$1.8 million in overcharges for 2001 within 30 days (refund report within 60 days)
- ISO to define and bill “other appropriate parties”
- ISO to file Compliance filing within 30 days



Purpose of 2004 GMC Rate Structure Project

- Initial Decision in ER01-313-000, *et.al.* (affirmed by Commission Order)
 - Requires ISO to reevaluate its rate structure
 - Requires evaluation of different proposals
- Settlement in ER02-250-000, et. al
- Analyze different rate structures
- Develop basis for new ISO rate structure effective January 1, 2004



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2004 GMC Rate Structure Project Materials

- 2004 GMC Rate Structure Project web page on
CAISO website
 - Documents
 - Public Discussion Board
 - Confidential Discussion Board
 - Accessible from
<http://www.caiso.com/docs/2002/08/02/2002080216283419989.html>



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Past 2004 GMC Rate Structure Project Events

- Past meetings and conference calls
 - August 2002 – February 2003 meetings and conference calls
 - March 4, 2003 – conference call
 - March 17, 2003 – conference call
 - April 11, 2003 – meeting at ISO
 - April 28, 2003 – meeting at ISO
 - May 7, 2003 – conference call
- Scheduled
 - May 12, 2003 – meeting at ISO
 - May 19, 2003 – conference call (tentative)
 - June 4, 2003 – meeting at ISO



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Participants

- Participants
 - CAC/EPUC, CDWR/SWP, CMUA, CPUC, EMS, EOB, FERC staff, IEP, MID, **Mirant**, NCPA, Navigant (representing municipal utilities), PG&E, SCE, Sempra, TID, WAPA



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Alternative Proposals

- Southern California Edison
- Modesto Irrigation District
- California ISO
- CPUC requested charges for FTR MWhs and ETCs

Exh. No. ISO- 273, Page 9 of 16



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SCE Functionalization of ISO Services

- Control Area Services (CAS)
- Dynamic Dispatch Export Services (DDES)
- Scheduling Service (SS)
- Market Operation Services (MOS)
- Real Time Operation Services (RTOS)



Indicative Rates under SCE Proposal

Service	Rate	Billing Determinant
CAS	\$0.70/MWh	Net control area load plus exports
DDES	\$0.07/MWh	Exports from Mohave to NP and SRP
SS	\$0.05/MWh	Scheduled load
MOS	\$0.71/MWh	Purchases and sales of AS and instructed energy
RMOS	\$1.01/MWh	Net uninstructed deviations
Rates are based on 2003 Budget amounts and billing determinants from the period September 2001 through August 2002. If this proposal is adopted, actual rates for 2004 will differ from those shown.		



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MID Functionalization of ISO Services

- Resolving Energy Imbalances (REI)
- Managing Transmission Flows (MTF)
- Administering Markets (AM)
- Forward Scheduling (FS)



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Indicative Rates under MID Proposal

Service	Rate	Billing Determinant
REI	\$125/customer-month	Non-coincident peak UE Net Uninstructed deviation
	\$456.62/MW-month	
	\$0.78/MWh	
MTF	\$375/customer-month	Non-coincident peak load Net control area load plus exports
	\$140.25/MW-month	
	\$0.16/MWh	
AM	\$2.28/MWh	Purchases and sales of AS and instructed energy
FS	\$1.49/schedule	Schedules submitted to SI (load, generation, import, export, inter-SC trade, awarded AS (including self- provided)
Rates are based on 2003 Budget amounts and billing determinants from the period September 2001 through August 2002. If this proposal is adopted, actual rates for 2004 will differ from those shown.		



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ISO Functionalization of Services

- Reliability Services
 - Core Reliability Services (CRS)
 - Energy & Transmission Services (ETS)
- Market Services
 - Forward Scheduling (FS)
 - Congestion Management
 - Market Usage (MU)
- ‘Customer Service’ (CS)



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Indicative Rates under ISO Proposal

Service	Rate	Billing Determinant
CRS	\$175/MW-month	Non-coincident peak demand including behind the meter demand
ETS	\$0.13/MWh \$0.47/MWh	Net control area load plus exports Net uninstructed deviations
FS	\$1.49/schedule	Schedules submitted to SI (load, generation, import, export, inter-SC trade, awarded AS (including self-provided)
CONG	\$0.11/MWh	Net scheduled interzonal flows
MU	\$0.63/MWh	Purchases and sales of AS, instructed energy and net uninstructed deviations
'CS'	TBD	Annual or monthly fee
Rates are based on 2003 Budget amounts and billing determinants from the period September 2001 through August 2002. Rates shown here do not include cost assignments of Settlements, Billing, Metering and Client Relations. If this proposal is adopted, actual rates for 2004 will differ from those shown.		



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Next Steps

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- **Timeline**
 - May – early June: Analyze bill impacts, continue to discuss functionalization
 - June 6: Initial presentation to ISO Board
 - June 26: Presentation to Board for approval
 - July: Incorporation into ISO Budget Process
 - November: FERC filing

Proposed Agenda
2004 GMC Rate Structure Project
Monday, May 12, 2003
Location: California ISO
101 Blue Ravine, Folsom
9:00 a.m. to 3:00 p.m.

Public Session (Conference Call-in #1-888-788-6681 Passcode: 98563)

1. Introductions/roll call
2. Stability of billing determinants
3. SCE proposal update
4. MID proposal update
5. ISO proposal update
 - a. Example bill calculation
 - b. Impact of 12 CP vs. 12 NCP on rates
 - c. Impact of DDES exemption on rates
 - d. Customer Service cost recovery discussion
6. Discussion of Order in ER01-313-000
7. Discussion of timeline

During lunch (12:00-1:00), there will be a conference call with the Parties to the 2002 GMC Settlement to discuss the impact of the FERC Order in ER01-313-000.

Confidential Session (a separate number will be distributed to parties that have executed the Non-Disclosure Agreement)

1. Discussion of billing impacts
 - a. SCE
 - i. Impact of DDES
 - b. MID
 - c. ISO
 - i. Impact of DDES
 - ii. Impact of 12 CP vs. 12 NCP

Created by: Ben Arikawa

CAISO

LSUPDT: 05/08/03

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Update on Modesto's GMC Proposal

**Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.
www.LRCA.com**

CAISO 2004 GMC Rate Design Project Meeting

**Folsom, California
May 12, 2003**

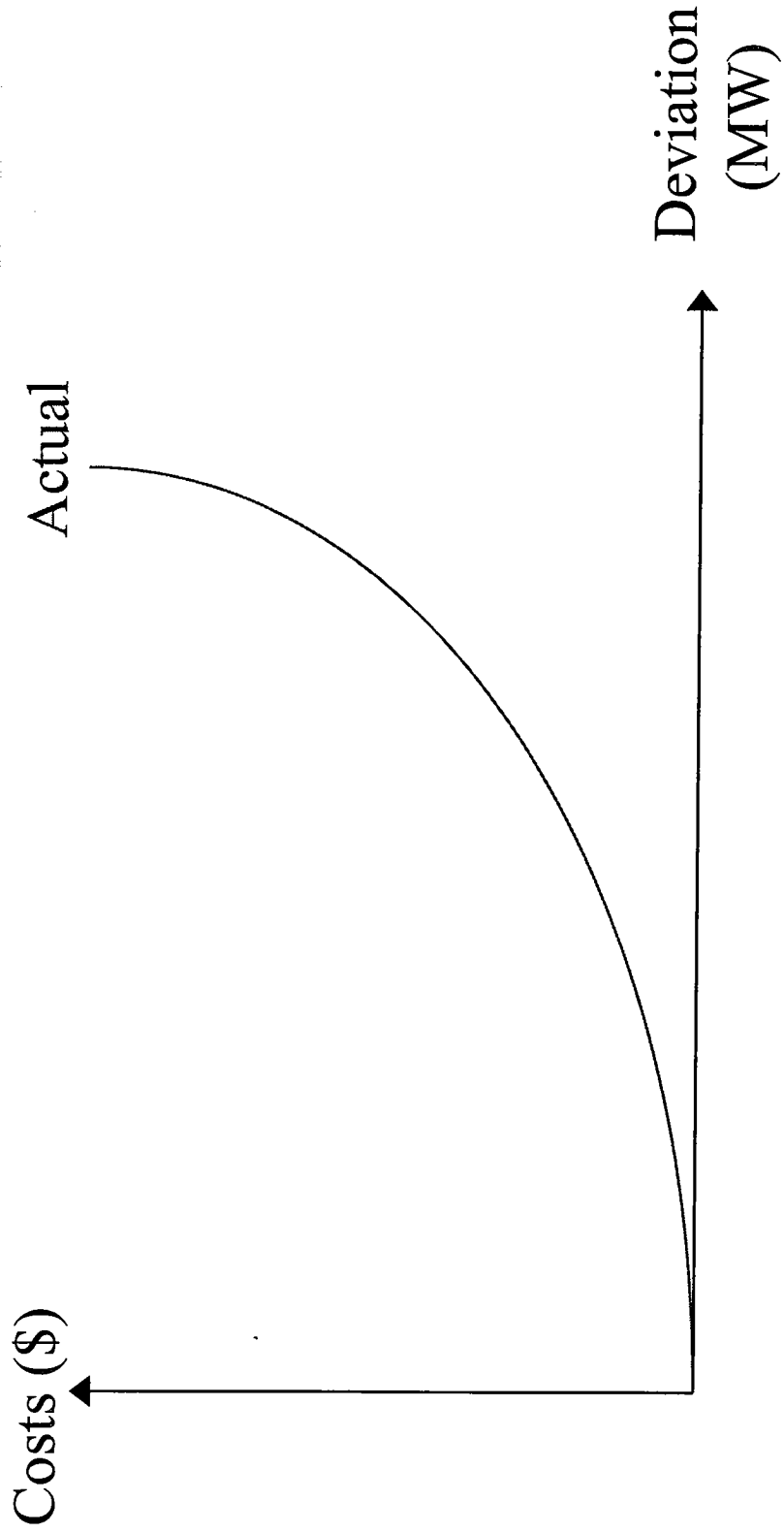


Recent Changes

1. Resolving Energy Imbalances
 - Adopt two-tier rate: Lower rates apply to smaller imbalances
2. Managing Transmission Flows
 - Eliminate the 12NCP demand charge: Recover all costs through energy charges

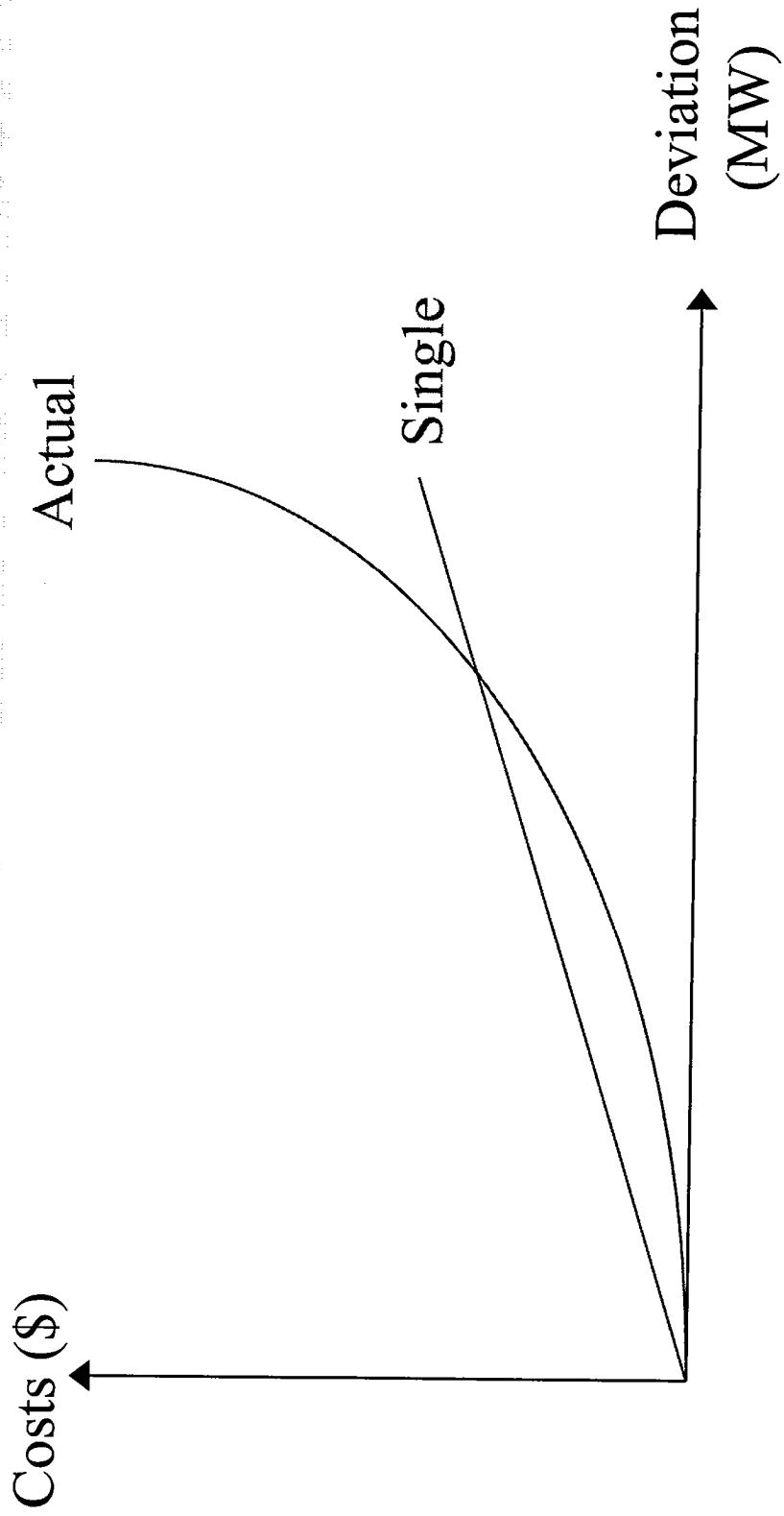
Resolving Energy Imbalances:

When Costs Exceed Demand



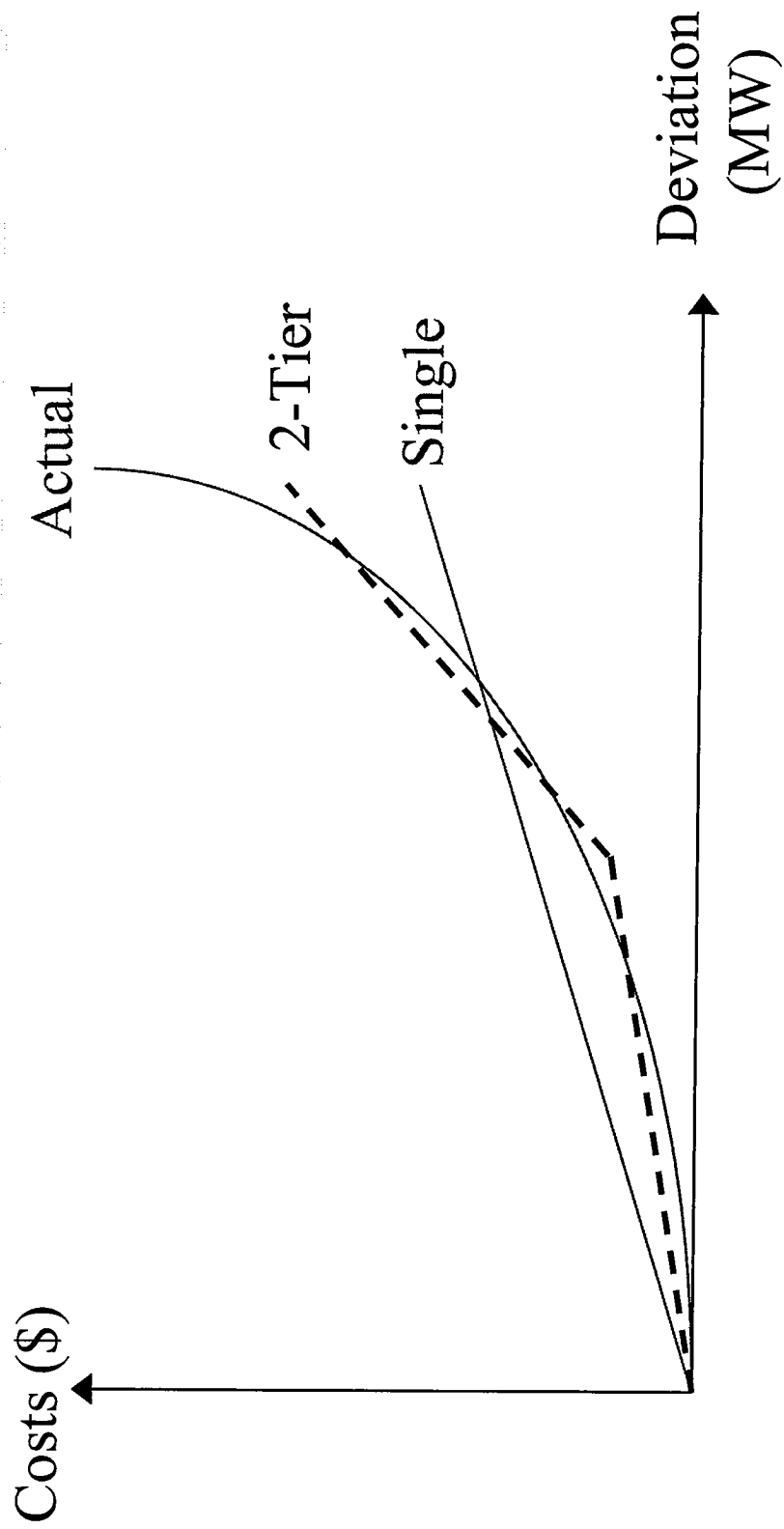
Resolving Energy Imbalances:

Example: For a 1000 MW capacity



Resolving Energy Imbalances:

Two-Tier Cost Recovery



Resolving Energy Imbalances: Alternatives

Single-Tier Rate

	Dollars	Quantity	Rate
uninstructed deviation energy	\$12,805,442	16,506,418 MWh	\$0.78 /MWh net deviation
uninstructed deviation demand	\$24,772,622	54,276 MW-months	\$456.42 /MW-month INCP net deviation
number of SCs	\$123,000	984 SC-months	\$125 /SC-month
	\$37,701,064		

Two-Tier Rate

	Dollars	Quantity	Rate
uninstructed deviation energy			
tier 1	\$280,866	4,873,932 MWh	\$0.0576 /MWh of 1st 5 MWh of net deviation
tier 2	\$12,524,576	11,577,685 MWh	\$1.0818 /MWh of over 5 MWh of net deviation
uninstructed deviation demand			
tier 1	\$49,658	3,806 MW-months	\$13.05 /MW-month of 1st 5 MW INCP net deviation
tier 2	\$24,722,964	46,319 MW-months	\$533.75 /MW-month of over 5 MW INCP net deviation
number of SCs	\$123,000	984 SC-months	\$125 /SC-month
	\$37,701,064		

Managing Transmission Flows

- Pros of eliminating the demand charge:
 - ISO costs are more related to system complexity than peak loads.
 - Demand-charge cost recovery may be unrelated to customer cost causations.
 - Cost shifts are smaller.
- Cons of eliminating the demand charge:
 - It may be appropriate to recover fixed costs through demand charges.

Managing Transmission Flows: Alternatives

Three-Part Rate

	Dollars	Quantity	Rate
power withdrawals	\$38,718,087	242,456,619 MWh	\$0.16 /MWh net load
maximum power withdrawals	\$74,901,637	534,042 MW-months	\$140.25 /MW-month 12NCP net load
number of SCs	\$369,000	984 SC-months	\$375 /SC-month
	\$113,988,724		

Two-Part Rate

	Dollars	Quantity	Rate
power withdrawals	\$113,619,724	242,456,619 MWh	\$0.4686 /MWh net load
number of SCs	\$369,000	984 SC-months	\$375 /SC-month
	\$113,988,724		

Our Updated Parameters

Function	Dollars	Quantity	Rate
Resolving Energy Imbalances			
uninstructed deviation energy			
tier 1	\$280,866	4,873,932 MWh	\$0.0576 /MWh of 1st 5 MWh of net deviation
tier 2	\$12,524,576	11,577,685 MWh	\$1.0818 /MWh of over 5 MWh of net deviation
uninstructed deviation demand			
tier 1	\$49,658	3,806 MW-months	\$13.05 /MW-month of 1st 5 MW INCP net deviation
tier 2	\$24,722,964	46,319 MW-months	\$533.75 /MW-month of over 5 MW INCP net deviation
number of SCs	\$123,000	984 SC-months	\$125 /SC-month
	\$37,701,064		
Managing Transmission Flows			
power withdrawals	\$113,619,724	242,456,619 MWh	\$0.4686 /MWh net load
number of SCs	\$369,000	984 SC-months	\$375 /SC-month
	\$113,988,724		
Administering Markets			
Trading volumes	\$66,870,735	29,327,169 MWh	\$2.2802 /MWh traded
Scheduling			
Forward Scheduling	\$19,039,848	12,716,097 schedules	\$1.4973 /schedule HA
Totals	\$237,600,371		

Bill Impacts of the MID Proposal

Redacted in the Courtroom

Classification	Less Than	Count	2003 GMC	MID Proposal	
				Old Parameters	New Parameters
Small	\$ 100,000	35	\$ 571,975	\$ 4,842,924	\$ 3,649,895
Medium	\$ 5,000,000	30	\$ 44,497,240	\$ 61,692,071	\$ 54,550,976
Large	\$ 100,000,000	7	\$ 192,531,156	\$ 171,065,376	\$ 179,399,500
Totals		72	\$ 237,600,371	\$ 237,600,371	\$ 237,600,371



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ISO Rate Proposal Update

2004 GMC Rate Structure Project

May 12, 2003

(revised)

Ben Arikawa

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Some Outstanding Issues

- Core Reliability Services
 - NCP MW of QFs and other entities
- Customer Service
 - Discussion on May 7 conference call
 - Method to associate CS with other billing determinants
- Data verification
- Mitigation



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Comments

- Complexity
- 12 CP instead of 12 NCP



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Example Rate Calculation

April 28, 2003

2004 GMC Rate Structure Project

David Timson

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Overview

- Example transaction includes SC-SC energy trade, flow across zonal interfaces, metered Load, Export volume, A/S allocation, and schedule deviations.
- Assume same transaction 24 x 7 for one month.
- Calculate charges with 2003 rates.
- Calculate charges with proposed rates.



Assumptions used in Example

- Scheduling Coordinator transaction for 1 hour;
 - Metered Energy consumption of 318 MWh (schedule = 300 MW)
 - Non-coincident demand of 503 MW-month (includes metered Load and Exports)
 - 200 MWh of scheduled exports from SP15 to AZ3
 - 500 MWh SC trades between NP15 and SP15 (through ZP26, net)
 - 35 MW A/S Operating Reserve allocation
 - 18 MWh Load deviation
 - Real-time Operational Adjustment to Export Schedule resulting in 15 MWh deviation (schedule was cut, 185 MWh were actually exported)
 - 3 final hour-ahead schedules



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Control Area Services (CT 521) Calculation

$$\text{CASC} = \text{CASR} * (\text{CAGL} + \text{SE})$$

- CASC = Control Area Service Charge due ISO
 - CASR = Control Area Service Rate = \$0.569/MWh
 - CAGL = SC's Control Area Gross Load = 318 MWh
 - SE = SC's Exports = 185 MWh
- $$\$285.70 = \$0.568 * (318 \text{ MWh} + 185 \text{ MWh})$$



Congestion Management (CT 522) Calculation

$$IZSC = IZSR * NFU$$

- IZSC= Congestion Management Charge due ISO
- IZSR = Congestion Management Charge Rate = \$0.320/MWh
- NFU = Final hour-ahead net inter-zonal New Firm Use flow of Scheduling Coordinator j along path p on operating date t and operating hour h. New Firm Use refers to transmission usage without Existing Transmission Contracts.

$$\$384.00 = \$0.320 * [200 \text{ MWh export} + (500 \text{ MWh} * 2 \text{ zonal interfaces})]$$

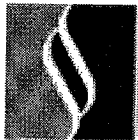


ASREO (CT 524) Calculation

$$\text{MOC} = \text{MOR} * [\text{ASP} + \text{ASS} + \text{IIE} + \text{UIE}]$$

- MOC = Market Operations Charge due ISO
- MOR = Market Operations Rate = \$1.296
- ASP = Ancillary Service purchases from SC = 0 MWh
- ASS = Ancillary Service sales (allocation) to SC = 35 MW
- IIE = Instructed Imbalance Energy for SC. This value is the net of
all IIE per SC per location per interval = 0 MWh
- UIE = Uninstructed Imbalance Energy = 18 MWh + 15 MWh = 33 MWh

$$\$88.13 = \$1.296 * (0 \text{ MWh} + 35 \text{ MW} + 0 \text{ MWh} + 33 \text{ MWh})$$



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Total GMC

- $\$285.70 + \$384.00 + \$88.13 = \$757.83/\text{hr}$
- Assume identical transaction each hour and 730 hours in average month
- Monthly charge in 2003 = $730 \times \$757.83 = \$553,216$



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Proposed Rates – Core Reliability Services

- Determinant = Gross non-coincident peak demand, MW (Load + Exports)
- 318 MW Load + 185 MW Exports = 503 MW x \$175.16/MW-Month = \$88,105.48/month



Proposed Rates – Energy and Transmission Services - Load

- Determinant = Net Control Area Load + Exports
- $(318 \text{ MWh} + 185 \text{ MWh}) \times \$126/\text{MWh} =$
\$63.38/hr



Proposed Rates – Energy and Transmission Services - Deviation

- Determinant = Absolute value of net uninstructed deviations by settlement interval (MWh)
- $(18 \text{ MWh} - 15 \text{ MWh}) \times \$465/\text{MWh} = \$1.40/\text{hr}$



Proposed Rates - Scheduling

- Determinant = Number of Final Hour-Ahead Schedules returned by Scheduling Infrastructure
- 3 final H/A schedules x \$1.497/schedule = \$4.49/hr



Proposed Rates – Congestion Management

- Determinant = Hour-ahead net inter-zonal New Firm Use flow (excludes ETCs)
- $[200 \text{ MWh export} + (500 \text{ MWh} * 2 \text{ zonal interfaces})] \times \$114/\text{MWh} = \$136.80/\text{hr}$



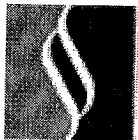
Proposed Rates – Market Usage

- Determinant = Purchases and sales of Ancillary Services, instructed energy, and absolute value of net uninstructed deviations.
- $[0 \text{ MWh} + 35 \text{ MW} + 0 \text{ MWh} + (18 \text{ MWh} - 15 \text{ MWh})] \times \$628/\text{MW} \text{ \& MWh} = \$20.72/\text{hr}$



Proposed Rates – Customer Service

- Determinant = Minimum of \$500/month fixed charge + \$.0289 per absolute value of all system generated billable quantities from final settlement statements for previous month.

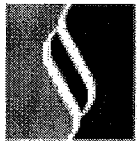


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Total Proposed GMC

- $\$63.38 + \$1.40 + \$4.49 + \$136.80 + \$20.72 = \$226.79/\text{hr}$
- Assume identical transaction each hour and 730 hours in average month
- Proposed monthly charge = $(730 \times \$226.79) + \$88,105.48 = \$253,662$ (Excluding Customer Service Charge)



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Questions?

Exh. No. ISO- 277, Page 16 of 16

Created By: dt

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LST UPDT: 04/25/2003

Disclaimer Regarding the Attached Data

The data is intended for the designated recipients only and is provided solely for the purpose of furthering discussion and research in the ISO's '2004 Rate Structure Project'. The data, in the form attached, is provided in response to Stakeholders' requests and as such does not necessarily indicate the ISO's concurrence in, or support for, its usefulness in developing a rate methodology. No implications may be drawn regarding the ISO's position on any subject in the Project from either the inclusion or exclusion of any specific data. The ISO does not warrant the completeness or accuracy of the data.

Date: May 9, 2003

This data is subject always to the Disclaimer issued by the ISO at the time of its distribution.

Comparison of Rates Under ISO Proposal
12 NCP vs. 12 CP

Core Reliability Services (\$/MW of
NCP demand)

12 NCP	\$	175.16
12 CP	\$	212.15

Note: The rates shown are for Core Reliability Services of the ISO Rate Proposal. The ISO proposes to use a 12 NCP rate to assess the CRS charge on non-coincident peak demand. The 12 CP rate is shown at the request of participants in the 2004 GMC Rate Structure Project. These data should be considered preliminary and subject to change.

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Comparison of Rates Under ISO Proposal Without and with Mohave Rate				
	CRS	CRS for Mohave	ETS	ETS for Mohave
Base Proposal without Mohave Rate \$	175.16		\$ 0.13	
Base Proposal with Mohave Rate \$	178.30	\$ 17.83	\$ 0.13	\$ 0.013

Note: The Mohave rate is assumed to be 10 percent of the applicable CRS and ETS rate. Mohave generation was assumed to be 3,300,000 MWhs. These data should be considered preliminary and subject to change.

Proposed Agenda
2004 GMC Rate Structure Project
Monday, May 12, 2003
Location: California ISO
101 Blue Ravine, Folsom
9:00 a.m. to 3:00 p.m.

Exh. No. ISO- 279, Page 1 of 7

Public Session (Conference Call-in #1-888-788-6681 Passcode: 98563)

1. Introductions/roll call
2. Stability of billing determinants
3. SCE proposal update
4. MID proposal update
5. ISO proposal update
 - a. Example bill calculation
 - b. Impact of 12 CP vs. 12 NCP on rates
 - c. Impact of DDES exemption on rates
 - d. Customer Service cost recovery discussion
6. Discussion of Order in ER01-313-000
7. Discussion of timeline

During lunch (12:00-1:00), there will be a conference call with the Parties to the 2002 GMC Settlement to discuss the impact of the FERC Order in ER01-313-000.

Confidential Session (a separate number will be distributed to parties that have executed the Non-Disclosure Agreement)

1. Discussion of billing impacts
 - a. SCE
 - i. Impact of DDES
 - b. MID
 - c. ISO
 - i. Impact of DDES
 - ii. Impact of 12 CP vs. 12 NCP

See notes below:

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See attached list for attendees.

The meeting started with a discussion of a document, "ETCs under MD02," that the ISO had issued previously on February 12, 2003. The ISO updated the document with the definition of an ETC and the Tariff sections that were relevant to ETC administration. The ISO had added the language at the request of David Cohen.

Mr. Cohen (Navigant) did not think that the additional language was sufficient. He specifically asked that a current date be placed on the document and that the ISO document how the figures shown were derived. He also asked for the ISO to make an attempt to estimate costs of programming ETC administration into the system applications. Finally, he asked that the ISO attach Appendix B of the Tariff identifying contract holders.

Tony Lam (EOB) agreed with Mr. Cohen that some measure of the "bottom line" cost of including ETC administration be added.

Kevin Smith (CMUA) asked if this document was prepared post-MSS implementation. Phil Leiber (ISO) responded that it was post-MSS implementation.

Southern California Edison was given the opportunity to give an update on its proposal. Bert Hansen (SCE) gave the SCE update. Mr. Hansen asked that a scenario be developed that included a DDES rate set at 25 percent of the applicable CAS or Reliability Services rate. The ISO responded that this would be done prior to the next meeting.

Mr. Hansen recounted the reasoning behind having a reduced charge for Mohave exports. There was some discussion of the ownership shares of Mohave and the parties to which exports were directed.

Mr. Cohen asked if Mr. Hansen had discussed the 25 percent rate with SCE management. Mr. Hansen had and SCE was willing to discuss the percentage with participants.

Mr. Cohen thought that his clients would accept the special rate if it applied only for one year and was used as a revenue credit back to the applicable CAS or Reliability Services revenue requirement. He thought that there might be other entities to which this rate could apply.

Other parties were uncertain if they or their clients would accept a special rate for Mohave exports to Nevada Power and Salt River Project. They did not have a clear understanding of the magnitude of bill impacts.

Mr. Hansen recounted the SCE offer to discuss the DDES charge or a comparable rate on Reliability Services. Mr. Cohen stated that he thought SCE had two choices: to push a negotiated settlement prior to the ISO filing or to litigate, in which SCE would be

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required to do a cost study to justify its assumption of 10 or 25 percent cost assignment to the DDES.

Dale Yakin (PG&E) asked the ISO's opinion of what whether special case contracts caused the ISO problems and if the ISO agreed with SCE on the level of effort associated with Mohave exports. Debi Le Vine (ISO) responded that the ISO had not done a separate study, but that it could look at the services provided to Mohave. She thought that the ISO provided some services to Mohave, but possibly not all services.

There was some discussion as to what services the DDES could be applied in the ISO rate proposal. Mr. Hansen replied that it could be applied to the Reliability Services, Core Reliability Services and Energy and Transmission Services.

Laurence Kirsch (Christensen Associates, MID) gave the next presentation for MID. Dr. Kirsch discussed the changes to the MID proposal. These changes were done to mitigate bill impacts. The specific changes were to create a two-tiered energy rate for Resolving Energy Imbalances and eliminating the demand charge on Managing Transmission Flows.

Dr. Kirsch gave a brief justification for a two-tiered energy charge by describing the ISO's Resolving Energy Imbalances cost function as a quadratic equation. This generated some discussion concerning the nature of the function and how it was determined to be quadratic. Several participants requested that the mathematics underlying this justification be developed and presented to participants.

Mr. Cohen asked if MID had considered developing a deviation bandwidth for the Resolving Energy Imbalances charge. The costs not recovered from the deviations would be rolled into the customer charge for this function. Mr. Cohen thought that this would reduce the complexity of the charge.

There was some discussion of what the deviation data represented and if the data that MID was using was consistent with the data the ISO was using.

At this point, the ISO began a discussion of the differences between "netting" for the purposes of the GMC and "netting" for market transactions. During part of this discussion, Kevin Smith asked if the application of the new GMC would be consistent with the terms of MSS agreements.

There were additional questions to Dr. Kirsch asking for clarification on how the demand charge in the Resolving Energy Imbalances was determined. Dr. Kirsch had taken the percentage allocations from the ISO's Reliability Services split between CRS and ETS.

Dr. Kirsch next presented the revised Managing Transmission Flows charge. The demand charge had been removed and these costs were recovered through a customer charge and a volumetric rate. CDWR noted that removal of the demand charge was counter to the recent FERC decision. CDWR also asked why MID chose non-

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coincident peak rather than coincident peak. Dr. Kirsch replied that an entity would have control over its own peak, but would not have control over the system peak.

There was some discussion of the bill impacts of the MID proposal. Dr. Kirsch stated that some SCs with little or no load, but many schedules would get big increases in their GMC bills.

Ben Arikawa (ISO) gave an update to the ISO proposal outlining what remained for the ISO to do. These were to update the billing determinant for CRS to include some measure of the behind the meter NCP, modification of the recovery of Customer Service costs consistent with the opinions expressed on the May 7th conference call, verification of data to address apparent anomalies and finally, additional mitigation to address significant bill impacts.

There was a discussion of comments on the ISO proposal received from participants. SCE raised the issue of whether generation connected at distribution level qualified as behind the meter. Mr. Hansen gave the example of a UDC with both generation and load behind a meter. Currently the ISO would charge the UDC only for the portion of load that was met with flows over transmission lines under a "net" approach. Mr. Hansen compared this with a more complex UDC with generators connected at the distribution level meeting the needs of non-retail customers. He thought that load of this more complex UDC should be reduced to account for this generation that did not touch transmission lines.

Mr. Cohen asked that the ISO should address Appendix B of the 2002 GMC Settlement, in particular the methodology for recovery of cost centers 1441 and 1424.

Mr. Hansen pointed out that the IOUs did not have a particular problem with passing GMC charges through to other entities. PG&E also agreed. The ISO noted that it would revise its presentation to remove this point.

David Timson (ISO) presented an example rate calculation. This presentation was done at the request of some participants who thought the billing of the ISO's GMC was complicated. The example that Mr. Timson presented was for an SC with load and exports, load, export, and inter-SC trade schedules and transactions crossing zonal boundaries.

There were a number of clarifying questions, such as, whether AS volumes were in MWhs or MWs (MWhs since the AS MWs are scheduled for one hour), whether the AS volumes included self-provided AS (does not), and how real time adjustments in load and generation are assessed charges (load following does not incur a charge for deviations).

There was a discussion of how schedules were processed and whether Day-Ahead schedules were processed differently than Hour-Ahead schedules. This discussion began from the observation that some SCs submitted Day-Ahead schedules 5 days in

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advance and the comment that having the schedules early must mean that it was less work for the ISO.

Mr. Timson's presentation was interrupted by a lunchtime conference call with parties to the 2002 GMC Settlement. This call was scheduled to meet the requirements of the Settlement to meet within 10 days of a FERC order on the Initial Decision in the 2001 GMC proceeding. This call was not part of the 2004 GMC Rate Structure Project, but was done at this time, as many of the parties to the Settlement were also participants in the Project.

After lunch, Mr. Timson continued his presentation. During the discussion of Congestion Management charges, Jim Ross (CAC) asked what entity would be charged (entity that schedules the energy across the interzonal boundary).

Mr. Cohen asked if the ISO would consider asking the Board to vote only on the functionalization portion of any rate proposal with the rate design issues being done after the June 26th Board meeting. Mr. Cohen expressed a desire to have the participants involved in the cost assignment and rate development. He wanted to know if the ISO and its consultants had sufficient information to do the cost assignment prior to the June 26th meeting.

The ISO responded that, though the rate development could follow the functionalization, it would be presenting full proposals to the Board.

Mr. Cohen asked what stakeholder process would be like after the June 26th Board vote.

Lee Terry (CWDR) asked what if the ISO could accept the use of the 12 CP (coincident peak) method. Ms. Le Vine replied that the ISO needed to staff its operations center to meet the demands placed on it regardless of the time of day, even in the middle of the night. She noted that the ISO needed to have operators to meet contingencies caused by disruptions not only at the time of system peak, but at other times, for entities with off-peak load.

During the confidential session, SCE gave its permission to release SC-related data in which SCE might be identifiable. This data showed the bill impacts to entities under the SCE proposal and under the ISO proposal using 12 NCP, 12 CP, and a Mohave rate that was 10 percent of the applicable CRS and ETS rates.

At the end of the confidential session, the meeting adjourned. The ISO committed to providing a list of outstanding issues prior to the next meeting on June 4th.

List of Attendees to May 12, 2003 GMC meeting

Aoki	Rod	CAC	(415) 421-4143	rsa@a-klaw.com
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Cogdill	Jan	ISO		
Cohen	David	Navigant Consulting	(503) 708-7852	dcohen@navigantconsulting.com
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Key	Jennifer	SCE		
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Kreamer	Perry M.	MID		
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Neal	Sean	MID		
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Yap	Catherine	Barkovich and Yap		
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2004 GMC Rate Structure Project Briefing

To: Participants in 2004 GMC Rate Structure Project
From: Ben T. Arikawa, Senior Financial Analyst
Date: May 14, 2003
Re: 2004 GMC Rate Structure Project related items

This Briefing contains:

- May 19th conference call;
- Meeting schedule for June;
- New postings of documents and data; and,
- Outstanding issues list from May 12th meeting.

May 19th conference call

The ISO would like to reschedule the May 19th conference call unless parties desire to have then. We do not have sufficient progress on updating our proposal in order to a meaningful discussion. We also have not had time to update the bill impacts using the latest rates of the MID proposal.

We propose a conference call for the week of May 26th for review of updates to the ISO proposal, as well as the SCE or MID proposal. Please e-mail me with suggested times for a conference call during that week.

Meeting schedule for June

The next meeting is scheduled for June 4, 2003, 9:00 – 3:00, at the ISO in Folsom.

We would also like you to consider an additional meeting in June. We have meeting rooms available on Thursday, June 19th and Friday, June 20th. We will firm up the date on the next conference call or at the June 4th meeting.

New postings of documents and data

We have posted draft notes for the April 11 and April 28 meetings and the May 7 conference call. Please review them for accuracy. If you have any edits or comments, please let me know.

On Tuesday, May 13, we posted on the confidential discussion board the spreadsheets and presentation from the confidential session of the Monday, May 12th meeting. Today, we also posted updates to those spreadsheets using

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a DDES and Mohave rate of 25 percent of the applicable Control Area Services or Reliability Services rates. These documents can be found at the bottom of the confidential discussion board page (items are listed in reverse chronological order). These documents replace any previous versions issued.

Finally, all public documents from the May 12th meeting have been posted to the GMC main web page, with the exception of the update to the "ETCs under MD02" document. Both the versions that were posted on May 9th and distributed during the May 12th meeting and the version originally distributed on February 12th have been taken off the GMC web page.

The GMC main web page and the discussion boards can be accessed from:

<http://www.caiso.com/docs/2002/08/02/2002080216283419989.html>.

If you would like a username and password, please let me know. You will need them in order to access the confidential discussion board.

Outstanding Issues List from May 12th meeting

Based on the discussion at the May 12th meeting, we developed this list of outstanding issues. If there are additional issues that are not captured on this list, please let us know.

Issue	Resolution
1. Calculate bill impacts using a DDES rate of 25% of CAS and RS rates	Done and posted on confidential discussion board, May 15, 2003, updated previous released spreadsheets
2. Listing and disposition of issues under Appendix B of the 2002 GMC Settlement	In progress
3. Amend comments of other parties in presentation on ISO Rate Proposal update	Done and updated version posted to GMC main web page, May 13, 2003
4. Amend ETCs under MD02 spreadsheet	All versions taken off GMC main web page pending revisions, May 13, 2003
5. Update Customer Service cost recovery consistent with conversation on May 7 th conference call	In progress
6. Update NCP to include measure of behind the meter load	In progress
7. Post spreadsheets showing calculations behind bill impacts of 12 CP, DDES and Mohave rate (i.e., GMC Analysis Tool)	In progress
8. Compile more recent data for all billing determinants	In progress
9. Update bill impacts using MID's latest update to their rate proposal	Not yet started

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If you have any questions about any of the information contained in this memorandum or about the process, please do not hesitate to contact:

Phil Leiber pleiber@caiso.com (916) 351-2168	Ben Arikawa barikawa@caiso.com (916) 608-5958
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Uninstructed energy tiers and scheduling clarification 05-19-03.txt
From: Arikawa, Ben
Sent: Monday, May 19, 2003 11:24 AM
To: Kirsch, Laurence
Cc: Hemphill, Ross; Pritchard, Jan
Subject: Uninstructed energy tiers and scheduling clarification

Laurence,

I compiled the tiered energy and NCP data using the dataset that I sent you. I was able to match the NCP MWs exactly, but the energy data does not match. I summarized my results and MID's in the attached spreadsheet.

The difference is small, about 11,000 MWhs.

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Ben Arikawa
Senior Financial Analyst
California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

Scheduling clarification 05-19-03.txt

From: Arikawa, Ben
Sent: Monday, May 19, 2003 11:43 AM
To: Kirsch, Laurence
Cc: Pritchard, Jan; Leiber, Phil; Morrison, Stephen
Subject: Scheduling clarification

Laurence,

I forgot to include this with the earlier e-mail on the data. In response to your request for clarification about what the ISO does for

SCs when it processes schedhe Board.t which time the $\square$ MC rate struc during the next conference call or at the next meeting. If your questions aren't specifically addressed, we can have one on one follow-up discussions.

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Proposed Agenda

2004 GMC Rate Structure Project

Wednesday, May 28, 2003

1:30 p.m. to 3:30 p.m.

Conference Call-in #1-888-788-6681 Passcode: 98563

1. Introductions/roll call
2. SCE proposal update
3. MID proposal update
4. ISO proposal update
 - a. Initial review of data and calculations
 - b. Implementation of Settlements, Metering and Client Relations cost recovery
 - c. Application of CRS charge to Standby Tariff NCP
5. Bill impact analysis
6. Initial discussion of scheduling activities
7. Initial review of Appendix B issues
8. Discussion of timeline

Created by: Ben Arikawa

CAISO

LSUPDT: 05/27/03

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2004 GMC Rate Structure Project

Comparison of Rate Proposals

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EXISTING STRUCTURE								
	Control Area Services	Congestion Management	Ancillary Services and Real Time Energy	Total				
% of Total	58%	12%	30%	100%				
Revenue Requirement	\$ 137,856,869	\$ 27,400,520	\$ 72,342,981	\$ 237,600,371				
9/2001-8/2002 Volume	251,615,170	87,927,387	73,292,051					
Rate / MWh	\$ 0.548	\$ 0.312	\$ 0.987					
Description	Gross Control Area Load & Exports	Net interzonal Scheduled load	Purchases & sales of A/S & RT Energy					
Previously used determinants	242,456,619	87,927,387	73,374,094					
ISO PROPOSED STRUCTURE								
	Core Reliability Services	Energy & Transmission Services Load	Energy & Transmission Services Deviation	Scheduling	Congestion Management	Market Operations	Customer Service	Total
% of Total	39%	13%	3%	8%	4%	12%	20%	100%
Revenue Requirement	\$ 93,544,836	\$ 30,670,132	\$ 7,667,533	\$ 19,039,848	\$ 10,017,448	\$ 28,775,078	\$ 47,885,496	\$ 237,600,371
9/2001-8/2002 Volume	536,762	242,456,619	16,403,169	12,307,710	87,927,387	45,707,872	1,562	
Rate / MW, MWh, Cust Mo	\$ 174.28	\$ 0.13	\$ 0.47	\$ 1.55	\$ 0.11	\$ 0.63	\$ 500.00	
Rate / MWh Cust Serv Adder		0.09	0.34		0.05	0.32		
Total Rate / MW, MWh, Cust Mo	\$ 174.28	\$ 0.22	\$ 0.81	\$ 1.55	\$ 0.16	\$ 0.95	\$ 500.00	
Description	Non-coincident peak demand/MW including diversified demand under Standby Tariffs	Net Control Area Load plus exports in MWh	Absolute value of net uninstructed deviations by settlement interval in MWh	Final HA schedules submitted, no charge for changes to DA schedules	Net Scheduled Interzonal load (flows)/MWh	Purchases and sales of Ancillary Services, instructed energy and absolute value of net uninstructed deviations by settlement interval	Number of customer months	
Previously used determinants	534,042	242,456,619.45	16,506,418.01	12,819,845	87,927,387	45,833,587	1,653,395,978	

MID PROPOSED STRUCTURE
Ver 1

	% of Total												
	5%	10%	0%	16%	31%	0%	28%	8%	100%				
Revenue Requirement	\$ 12,788,124	\$ 24,739,120	\$ 173,820	\$ 38,666,133	\$ 74,801,131	\$ 521,460	\$ 66,870,735	\$ 19,039,848	\$237,600,371				
9/2001-8/2002 Volume	16,403,169	45,688	1,562	242,456,619	534,042	1,562	29,304,703	12,307,710					
Rate / MW, MWh, Cust Mo	\$ 0.78	\$ 541.47	\$ 111.28	\$ 0.16	\$ 140.07	\$ 333.84	\$ 2.28	\$ 1.55					
Description	Uninstructed deviation energy	Uninstructed deviation demand (most recent 12 months)	Number of customer months	Power withdrawals	Maximum power withdrawals	Number of customer months	Trading volumes	Trading volumes	Trading volumes				
Previously used determinants	16,506,418	25,238	984	242,456,619	534,042	984	29,327,169	12,819,845					

MID PROPOSED STRUCTURE
Ver 2

	5%		10%		0%		48%		0%		28%		8%		100%	
% of Total																
Revenue Requirement	\$	12,780,821	\$	24,724,993	\$	195,250	\$	113,402,974	\$	585,750	\$	66,870,735	\$	19,039,848	\$	237,600,371
9/2001-8/2002 Volume Base/Tier 1		4,868,337		3,746		1,562		242,456,619		0		1,562		29,304,703		12,307,710
9/2001-8/2002 Volume Tier 2		11,534,832		44,179												
Rate / MW or MWh Base/Tier 1	\$	0.06	\$	13.23	\$	125.00	\$	0.47	\$	-	\$	375.00	\$	2.28	\$	1.55
Rate / MW or MWh Tier 2	\$	1.08	\$	558.53												
Description		Uninstructed deviation energy		Uninstructed deviation demand (most recent 12 months)		Number of customer months		Power withdrawals		Number of customer months		Trading volumes		Trading volumes		Trading volumes
Previously used determinants		16,403,169		47,926		984		242,456,619		534,042		984		29,327,169		12,819,845
Previously used determinants		16,506,418		25,238		984										

SCE PROPOSED STRUCTURE	CAS	DDES	SS	MOS	RMOS	Total
---------------------------	-----	------	----	-----	------	-------

% of Total	70.3%	0.1%	6.8%	15.6%	7.1%	100.0%
Revenue Requirement	\$ 167,089,477	\$ 230,558	\$ 16,270,959	\$ 37,136,426	\$ 16,872,951	\$ 237,600,371
9/2001-8/2002 Volume	239,156,619	3,300,000	237,779,865	29,304,703	16,403,169	
Rate / MW or MWh	\$ 0.699	\$ 0.070	\$ 0.068	\$ 1.267	\$ 1.029	
Description	MWh of Control Area Load (Exclusive of retail behind-the-meter)	MWhs of gen dynamically dispatched to other Control Areas over non-ISO T	MWh of scheduled energy + self-provided AS (final schedules)	MWh of pur/sales of energy + AS	MWh of uninstructed imbalance energy	
Previously used determinants	239,156,619	3,300,000	244,244,847	29,327,169	16,506,418	

DWR Variation on ISO Proposed Structure	Core Reliability Services	Energy & Transmission Services	Energy & Transmission Services Deviation Load	Scheduling	Congestion Management	Market Operations	Customer Service	Total
--	------------------------------	--------------------------------------	--	------------	--------------------------	-------------------	------------------	-------

% of Total	39%	13%	3%	8%	4%	12%	20%	100%
Revenue Requirement	\$ 93,544,836	\$ 30,670,132	\$ 7,667,533	\$ 19,039,848	\$ 10,017,448	\$ 28,775,078	\$ 47,885,496	\$ 237,600,371
9/2001-8/2002 Volume	440,946	242,456,619.45	16,403,168.73	12,307,710	87,927,387	45,707,872	1,562	
Rate / MW, MWh, Cust Mo	\$ 212.15	\$ 0.13	\$ 0.47	\$ 1.55	\$ 0.11	\$ 0.63	\$ 500.00	
Rate / MWh Cust Serv Adder	\$ 212.15	\$ 0.09	\$ 0.34	\$ 1.55	\$ 0.05	\$ 0.32	\$ 500.00	
Total Rate / MW, MWh, Cust Mo	\$ 212.15	\$ 0.22	\$ 0.81	\$ 1.55	\$ 0.16	\$ 0.95	\$ 500.00	
Description	Gross coincident peak demand MW-- 12 CP Basis	Net Control Area Load plus exports in MWh	Absolute value of net uninstructed deviations by settlement interval in MWh	Final HA schedules submitted, no charge for changes to DA schedules	Net Scheduled Interzonal load (flows)MWh	Purchases and sales of Ancillary Services, instructed energy and absolute value of net uninstructed deviations by settlement interval	Minimum of \$500/mo	
Previously used determinants	440,946	242,456,619.45	16,506,418.01	12,819,845	87,927,387	45,833,587	1,653,395,978	

Note: The following is pasted from the GMC Analysis Tool-MID & MID file REI Data.xls

Resolving Energy Imbalances	Managing Transmission Flows	Administering Markets	Scheduling
Resolving Energy Imbalances	Managing Transmission Flows	Administering Markets	Scheduling

Revenue Requirement		% of Total		8%		16%		28%		5%		16%		28%		8%	
9/2001-8/2002 Volume		12,810,042		19,039,848		12,819,845		66,870,735		12,805,442		113,619,724		66,870,735		\$ 19,039,848	
9/2001-8/2002 Volume		16,506,418		12,819,845		29,327,169		242,456,619		4,873,932		242,456,619		29,327,169		12,716,097	
Description		Uninstructed deviation energy		Trading volumes		Trading volumes		Power withdrawals		Uninstructed deviation energy		Trading volumes		Trading volumes		Trading volumes	
Rate / MW or MWh		\$ 0.7761		\$ 1.4852		\$ 2.2802		\$ 0.1597		\$ 0.0576		\$ 0.4686		\$ 2.2802		\$ 1.4973	
										Rate / MWh: Tier 1		Rate / MWh: Tier 2					
										Rate / MWh: Tier 1		Rate / MWh: Tier 2					

% of Total		Ratio of REI-1 to MTF-2 REI Ratio of MTF-1 to MTF-2	Ratio of Tier 1 & 2 Rev	Ratios of Tier 1 & 2 Rev
Revenue Requirement 9/2001-8/2002 Volume	\$ 24,781,522	\$ 74,928,336	34%	REI-1 2%
	25,238	534,042	34%	REI-2 0.2%
Description	Uninstructed deviation demand (most recent 12 months)	Maximum power withdrawals		99.8%
Rate / MW:	\$ 981.92	\$ 140.30		

	% of Total
Revenue Requirement	
9/2007-8/2002 Volume	
Description	
Rate / Customer Month	

	% of Total	0%	0%
Revenue Requirement	\$	123,000	\$ 369,000
2001-8/2002 Volume		984	984
Description	Number of customer months	Number of customer months	Number of customer months
Rate / Customer Month	\$	125.00	\$ 375.00

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	Current Annual GMC charge		Proposed Annual GMC charge	
	\$0.57 per MWh		#####	
PG&E				
Total	\$	1,224,857	\$	213,530
SCE				
Total	\$	1,847,326	\$	228,273
SDG&E				
Total	\$	261,637	\$	34,641
Total 3 IOUs	\$	3,333,821	\$	476,444

re time of its distribution.

Change

\$(1,011,327)

\$(1,619,053)

\$ (226,997)

\$(2,857,377)

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	Current Annual GMC charge \$0.57 per MWh
PG&E	
Small Standby @ Transmission	\$ -
Small Standby @ Primary Distribution	\$ 825
Small Standby @ Secondary Distribution	\$ 3,511
Large Standby @ Transmission	\$ 1,084,105
Large Standby @ Primary Distribution	\$ 134,698
Large Standby @ Secondary Distribution	\$ 1,718
Total	<u>\$ 1,224,857</u>
SCE	
Small Standby @ Secondary Distribution	\$ 2,990
Large Standby @ Transmission	\$ 1,587,137
Large Standby @ Primary Distribution	\$ 239,950
Large Standby @ Secondary Distribution	\$ 17,249
Total	<u>\$ 1,847,326</u>
SDG&E	
Small Standby	\$ 2
Large Standby	\$ 261,636
Total	<u>\$ 261,637</u>
Total 3 IOUs	<u>\$ 3,333,821</u>

/ the ISO at the time of its distribution.

Proposed Annual GMC charge	Change
#####	
\$ 259	\$ 259
\$ 567	\$ (258)
\$ 985	\$ (2,526)
\$ 185,790	\$ (898,315)
\$ 25,062	\$ (109,636)
\$ 867	\$ (851)
<u>\$ 213,530</u>	<u>\$ (1,011,327)</u>
\$ 3,653	\$ 663
\$ 170,377	\$ (1,416,760)
\$ 47,399	\$ (192,550)
\$ 6,844	\$ (10,405)
<u>\$ 228,273</u>	<u>\$ (1,619,053)</u>
\$ 1	\$ (1)
\$ 34,640	\$ (226,996)
<u>\$ 34,641</u>	<u>\$ (226,997)</u>
<u>\$ 476,444</u>	<u>\$ (2,857,377)</u>

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	Contract Capacity (kW)	Effective Demand Factor
PG&E		
Small Standby @ Transmission	770	0.16
Small Standby @ Primary Distribution	1,227	0.22
Small Standby @ Secondary Distribution	2,130	0.22
Large Standby @ Transmission	552,429	0.16
Large Standby @ Primary Distribution	54,195	0.22
Large Standby @ Secondary Distribution	1,875	0.22
Total	<u>612,626</u>	
SCE		
Small Standby @ Secondary Distribution	7,900	0.22
Large Standby @ Transmission	506,600	0.16
Large Standby @ Primary Distribution	102,500	0.22
Large Standby @ Secondary Distribution	14,800	0.22
Total	<u>631,800</u>	
SDG&E		
Small Standby	2.0	0.22
Large Standby	102,998	0.16
Total	<u>103,000</u>	
Total 3 IOUs	<u>1,347,426</u>	

Note:

Effective demand factor taken from Appendix B: Circuit Analysis for Determining Effective Demand, "Phase 2 of 2003 General Rate Case Marginal Cost and Revenue Proposals," SCE, March 2003.

e time of its distribution.

Effective Demand
(kW)

123
270
469
88,389
11,923
412
<u>101,586</u>

1,738
81,056
22,550
3,256
<u>108,600</u>

0
<u>16,480</u>
<u>16,480</u>
<u>226,666</u>

mination of
nd Sales Forecast

Table B-3
Effective Demand Factors by Standby Customers

Group	12 kV	66 kV	220 kV
Less than 50 kV	0.22	0.06	0.04
Greater than 50 kV		0.16	0.01

From Appendix B: Circuit Analysis for Determination of Effective Demand, "Phase 2 of 2003 General Rate Case Marginal Cost and Sales Forecast Proposals," SCE, March 2003, p. B-11.

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Estimation of Gross Load for Standby Customers

	Contract Capacity (kW)	Comparable Full Service Class	Full Service Load Factor
PG&E			
Small Standby @ Transmission	770	E19VT	0.0%
Small Standby @ Primary Distribution	1,227	A10P, E19VP	13.5%
Small Standby @ Secondary Distribution	2,130	A10S, E19VS	33.1%
Large Standby @ Transmission	552,429	E19T, E20T	39.4%
Large Standby @ Primary Distribution	54,195	E19P, E19P	49.9%
Large Standby @ Secondary Distribution	1,875	E19S, E20S	18.4%
Total	<u>612,626</u>		40.1%
SCE			
Small Standby @ Secondary Distribution	7,900	GS-2	7.6%
Large Standby @ Transmission	506,600	TOU-8-SUB	62.9%
Large Standby @ Primary Distribution	102,500	TOU-8-PRI	47.0%
Large Standby @ Secondary Distribution	14,800	TOU-8-SEC	23.4%
Total	<u>631,800</u>		58.7%
SDG&E			
Small Standby	2.0	A	15.2%
Large Standby	102,998	>20 kW	51.0%
Total	<u>103,000</u>		51.0%
Total 3 IOUs	<u>1,347,426</u>		49.7%

Notes:

Data originally from Exhibit 13 of James Price's testimony in ER01-313-000

istribution.

Average Demand (kW)	Annual Demand MWh	Monthly Demand MWh
-	-	-
166	1,451	121
705	6,175	515
217,657	1,906,676	158,890
27,043	236,900	19,742
345	3,022	252
245,916	2,154,225	179,519

600	5,260	438
318,651	2,791,386	232,616
48,175	422,013	35,168
3,463	30,338	2,528
370,890	3,248,996	270,750

0.3	2.7	0.22
52,529	460,154	38,346
52,529	460,157	38,346
669,335	5,863,377	488,615



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Preliminary Bill Impacts

2004 GMC Rate Structure Project

May 28, 2003

Ben Arikawa

(916) 608-5958

barikawa@caiso.com

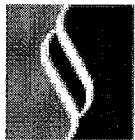
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What is New?

- Initial data verification
 - SC IDs
 - Duplicate data
- Behind the meter Standby NCP

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Bill Impacts

- SCE Proposal
- MID Proposal
- ISO Proposal (12 NCP)
- DWR Proposal (12 CP)

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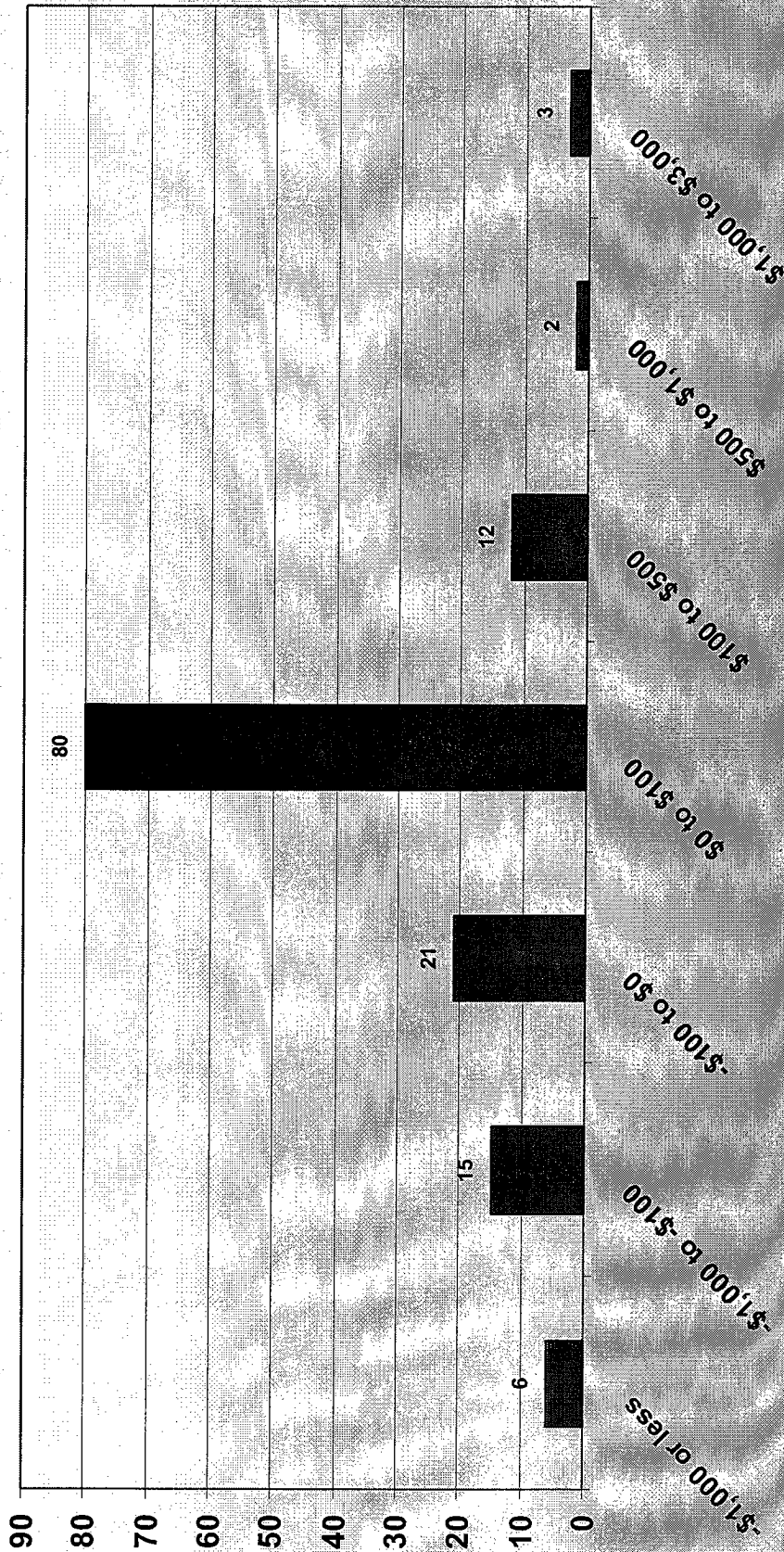
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Distribution of Bill Impacts: SCE Proposal (in thousands of dollars)



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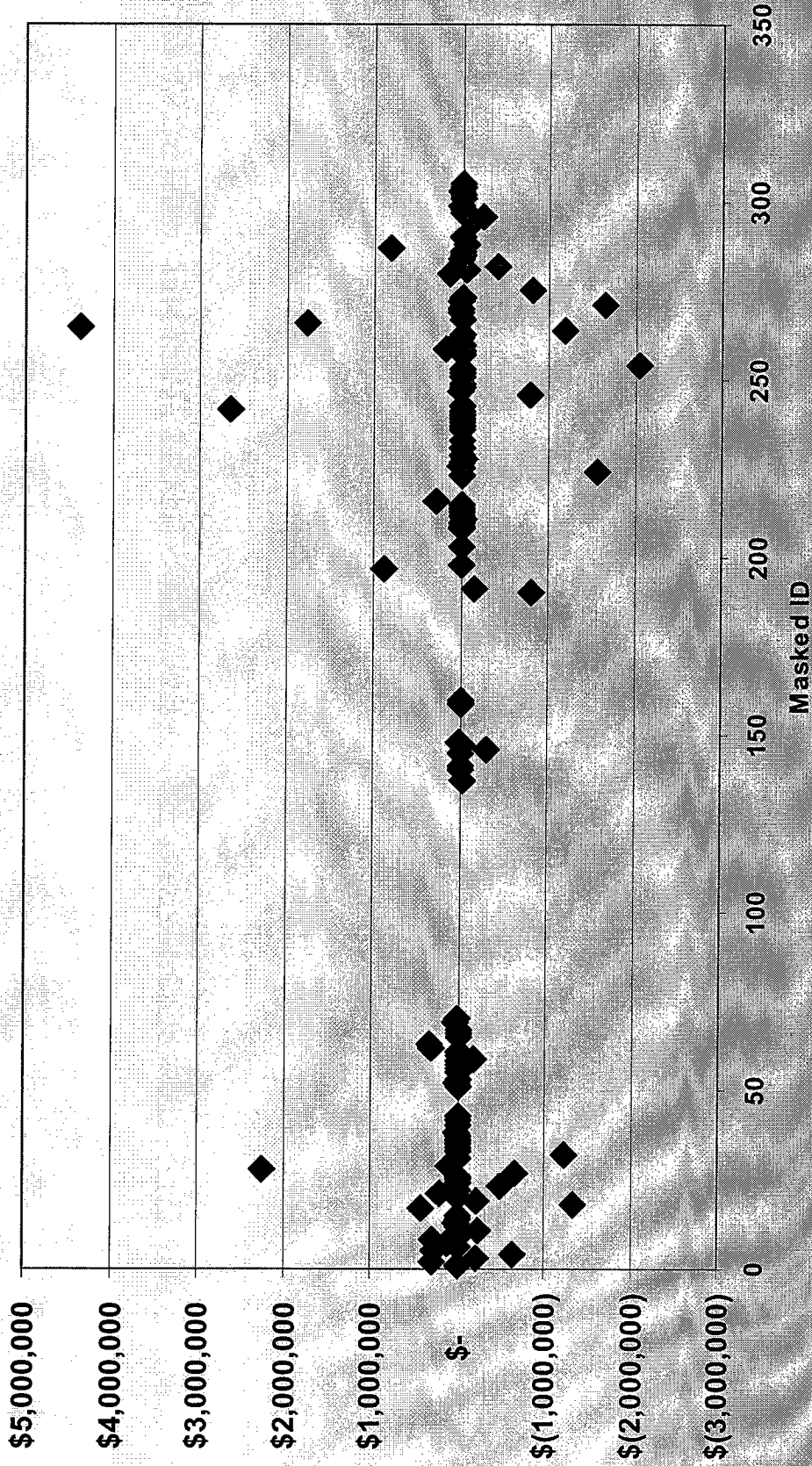
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Distribution of Bill Impacts SCE Rate Proposal

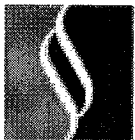


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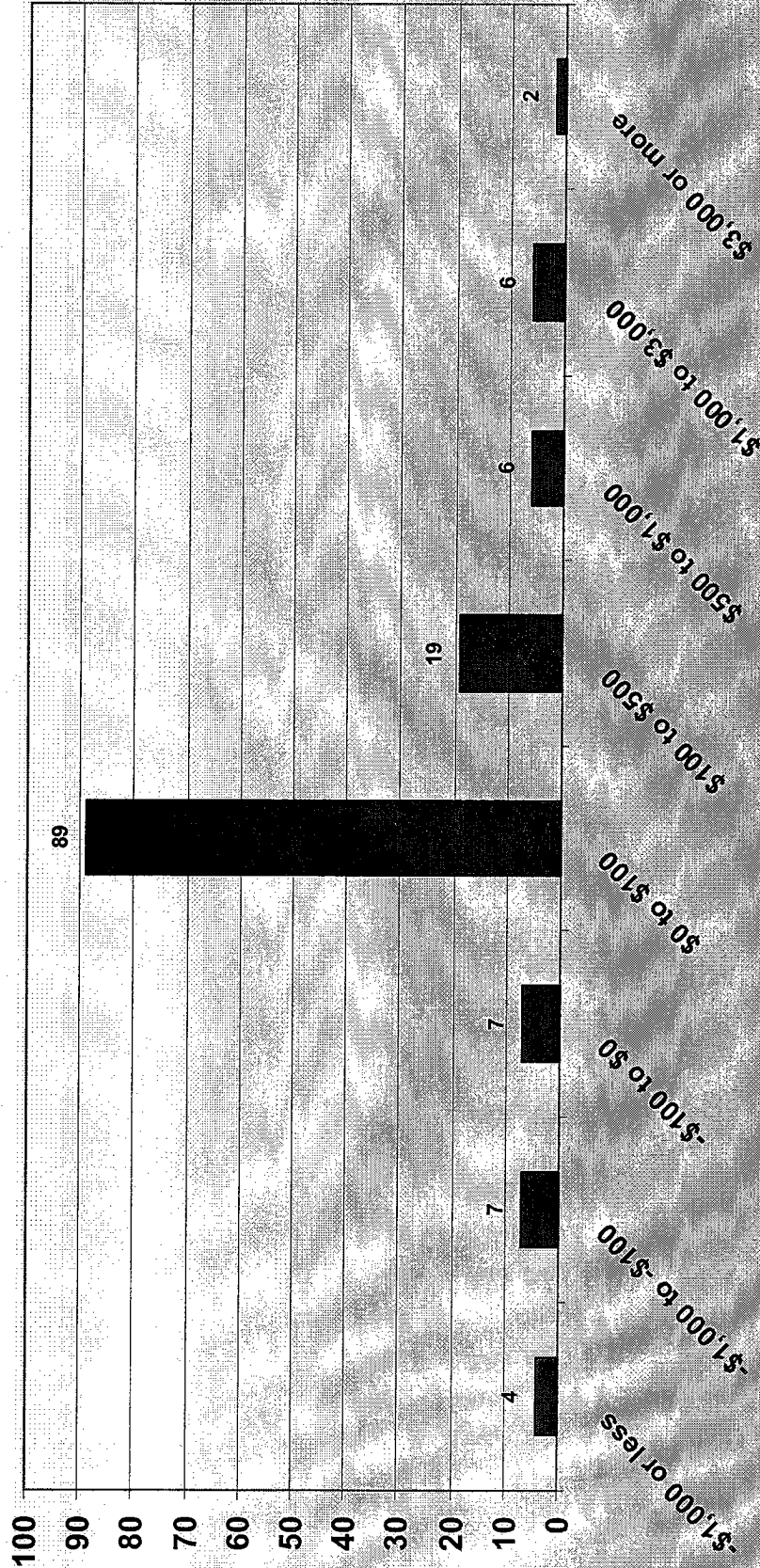
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Distribution of Bill Impacts: MID Proposal (in thousands of dollars)



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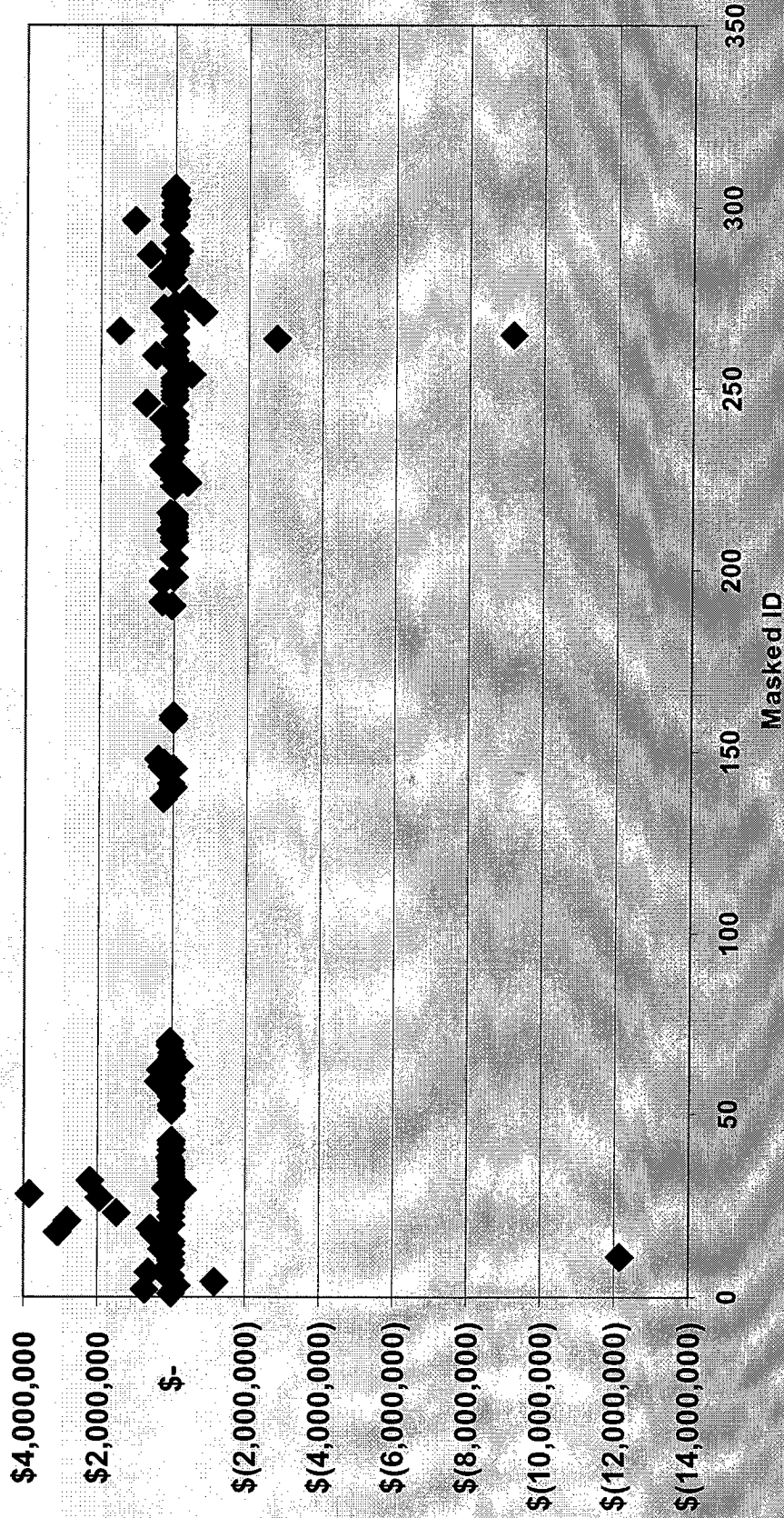
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Distribution of Bill Impacts MID Proposal



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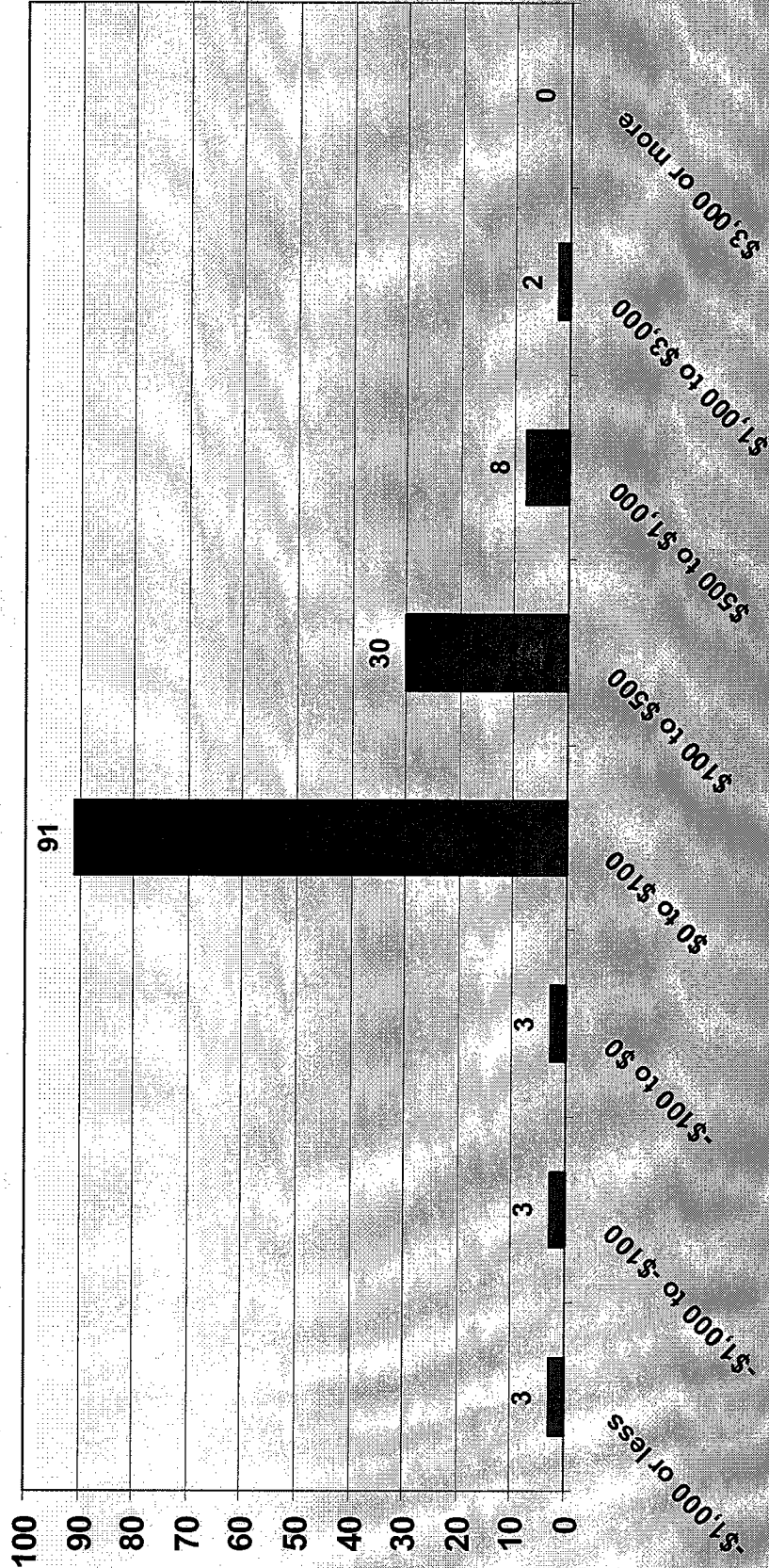
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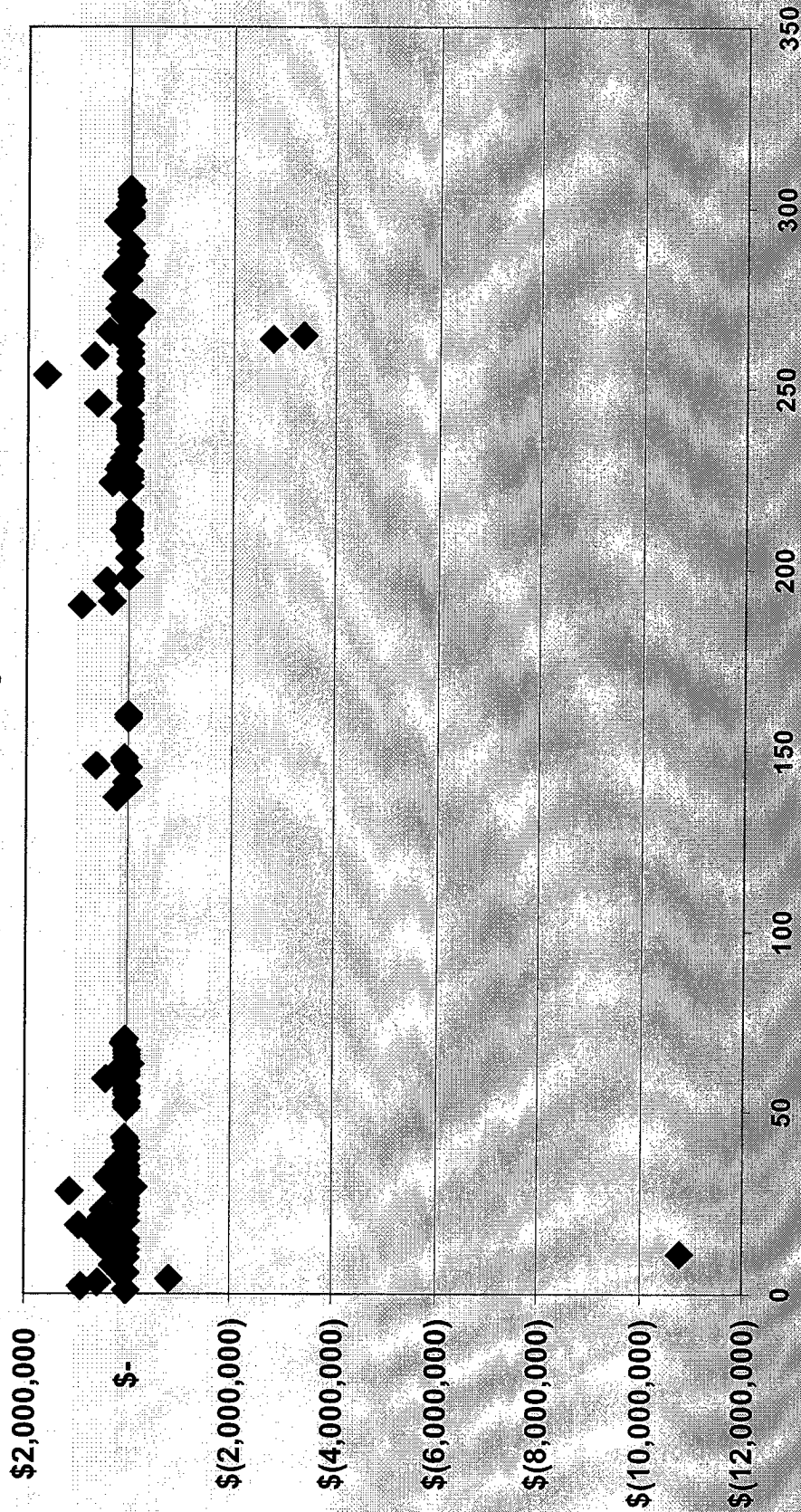
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Distribution of Bill Impacts ISO Rate Proposal



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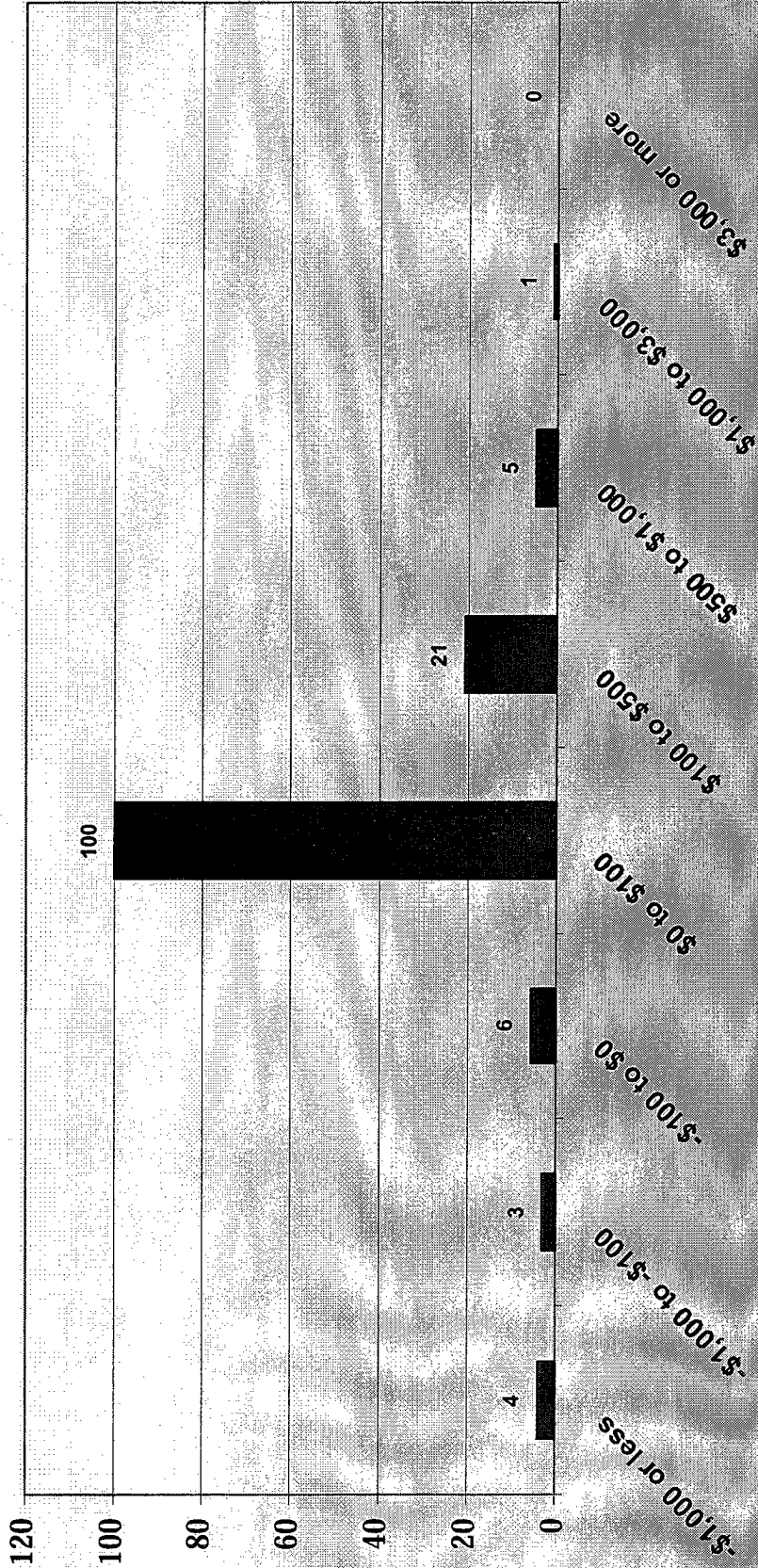
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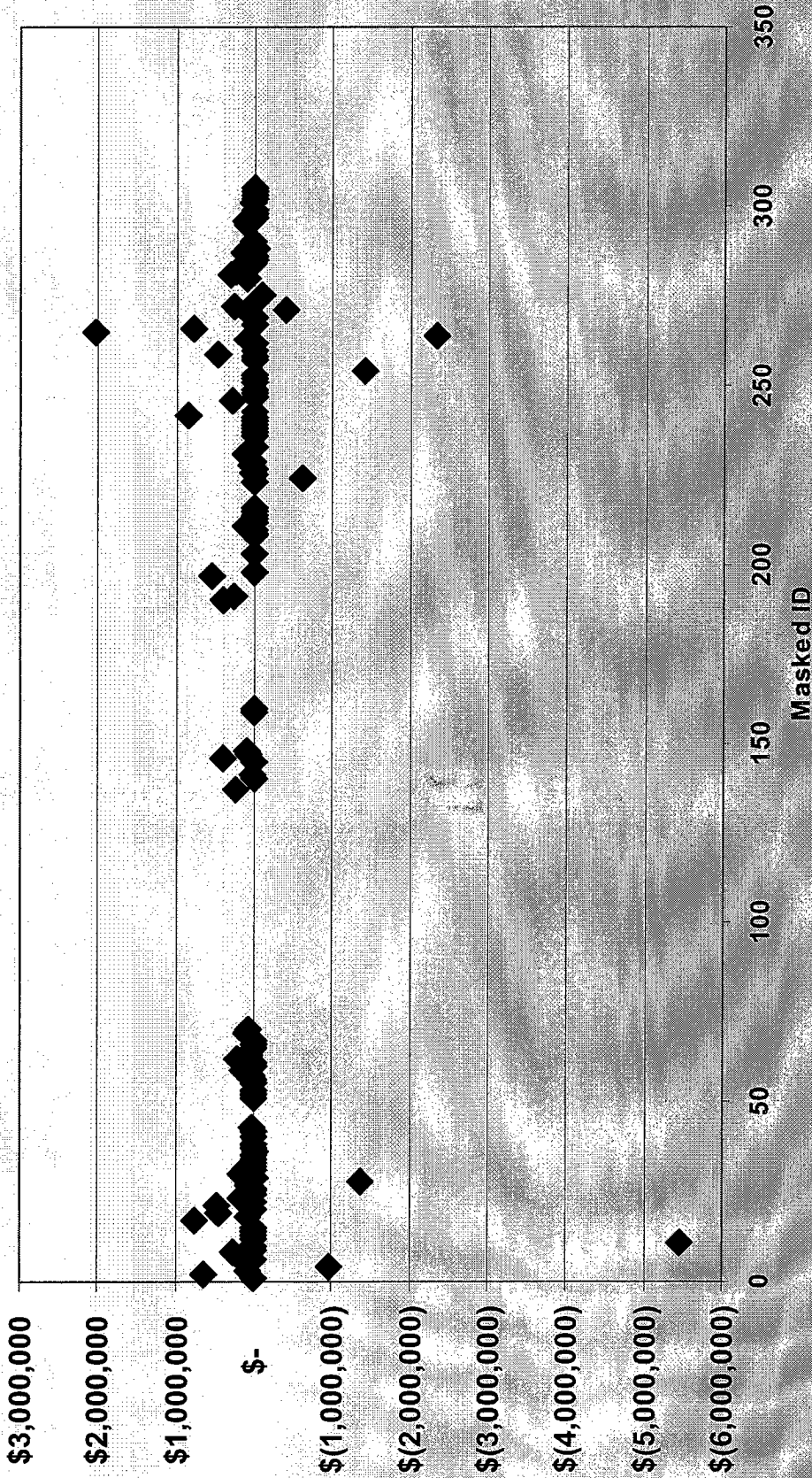
LST UPDT: 05/28/2003



CALIFORNIA ISO

California Independent
System Operator

Distribution of Bill Impacts DWR Rate Proposal (12 CP)



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Next Steps

- Review of data
- Review of calculations
- Introduce NCP of behind the meter muni load
- Pursue additional mitigation, if necessary

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California ISO

Disclaimer Regarding the Attached Data

purpose of furthering discussion and research in the ISO's '2004 GMC Rate Structure Project'. The data, in the form attached, is provided in response to Stakeholders' requests and as such does not necessarily indicate the ISO's concurrence in, or support for, its usefulness in developing a rate methodology. No implications may be drawn regarding the ISO's position on any subject in the Project from either the inclusion or exclusion of any specific data. The ISO does not warrant the completeness or accuracy of the data.

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tion.

Assessment of Rate Impact with Functional Association of Customer Service Revenues Based on Charge Type Analysis

Existing Rates		Control Area Services	Congestion Management	Ancillary Services and Real Time Energy					
% of Total		58%	12%	30%					
Revenue Requirement		\$ 137,856,869	\$ 27,400,520	\$ 72,342,981					
9/2001-8/2002 Volume		242,456,619	87,927,387	73,374,094					
Rate / MWh		\$ 0.569	\$ 0.312	\$ 0.986					
Description of Billing Determinant		Gross Control Area Load & Exports	Net Interzonal Scheduled load	Purchases & sales of A/S & RT Energy					
New Rate Design		Core Reliability Services	Energy & Transmission Services Load	Energy & Transmission Services Deviation	Congestion Management	Scheduling	Market Operations	Customer Service	
% of Total		39%	13%	3%	4%	8%	12%	20%	
Revenue Requirement		\$ 93,544,836	\$ 30,670,132	\$ 7,667,533	\$ 10,017,448	\$ 19,039,848	\$ 28,775,078	\$ 47,885,496	
9/2001-8/2002 Volume		536,762	242,456,619	16,403,169	87,927,387	12,307,710	45,707,872	1,562	
Rate / MWh or MWh		\$ 174.28	\$ 0.13	\$ 0.47	\$ 0.11	\$ 1.55	\$ 0.63	\$ 500	
Calculation of Rates After Customer Service Revenues Are Reassigned									
Cust Add Rate Opt 1 /1		\$	0.09	\$ 0.34	\$ 0.05	\$	0.32	\$	
Total Rate Opt 1		\$ 174.28	\$ 0.22	\$ 0.81	\$ 0.16	\$ 1.55	\$ 0.95	\$ 500	
Description of Billing Determinant		Non-coincident peak demand/MW including diversified demand under Standby Tariffs	Net Control Area Load plus exports in MWh	Absolute value of net uninstructed deviations by settlement interval in MWh	Net Scheduled Interzonal load (flows)MWh	Final HA schedules submitted, no charge for changes to DA schedules	Purchases and sales of Ancillary Services, instructed energy and absolute value of net uninstructed deviations by settlement interval MWh	Per customer month	

Association of Settlement System with Functional Categories

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Charge Type ID	Charge Description	Billable Quantity	Price	Count of Charge Types and Functional Association on a Count Basis	No of Trans w/Chg Type	Percent age	CAS Count	CONG Count	Sched Count	MS Count
1	Day Ahead Spinning Reserve due SC	Spinning Reserve accepted bid quantity [per SC, per location]			1,917	0.9%	1,438			479
2	Day Ahead Non-Spinning Reserve due SC	Non-Spinning Reserve Accepted Bid Quantity [per SC, per location]			1,452	0.7%	1,089			363
4	Day Ahead Replacement Reserve due SC	Replacement Reserve Accepted Bid Quantity [per SC, per location]			506	0.2%	380			127
5	Day Ahead Regulation Up due SC	Day Ahead Regulation Up Accepted Bid Quantity [per SC, per location]			1,818	0.9%	1,364			455
6	Day Ahead Regulation Down due SC	Day Ahead Regulation Down Accepted Bid Quantity [per SC, per location]			1,931	0.9%	1,448			483
7	Demand Relief Monthly Capacity Payment	location]			6	0.0%	5			2
24	Withhold	[per SC, per location]	compliance less than 90%		189	0.1%	142			47
51	Hour Ahead Spinning Reserve due SC	Hour Ahead additional Spinning Reserve accepted bid quantity [per SC, per location]	hour for its bid in Capacity		2,336	1.1%	1,752			584
52	Hour Ahead Non-Spinning Reserve due SC	location]	Price = Max (Bid price, HA Zonal Non-Spinning Reserve MCP)		1,938	0.9%	1,454			485
54	Hour Ahead Replacement Reserve due SC	location]	Price = Max (Bid price, HA Zonal Replacement Reserve MCP)		918	0.4%	689			230
55	Hour Ahead Regulation Up due SC	Hour Ahead Regulation Up Accepted Bid Quantity [per SC, per location]	Price = Max (Bid price, HA Zonal Regulation Up MCP)		1,958	0.9%	1,469			490
56	Hour Ahead Regulation Down due SC	Hour Ahead Regulation Down Accepted Bid Quantity [per SC, per location]	Price = Max (Bid price, HA Zonal Regulation Down MCP)		1,981	0.9%	1,486			495
61	(HA Price)	location]	Zonal Spinning Reserve Capacity Hour Ahead Market Clearing Price for Trading Interval		1	0.0%	1			1
65	Amount of Regulation Up Pre-empted below close of HA Market [per SC, per location]	location]	Zonal Regulation Up Capacity Hour Ahead Market Clearing Price for Trading Interval		1	0.0%	1			1
66	(HA Price)	location]	Zonal Regulation Down Capacity Hour Ahead Market Clearing Price for Trading Interval		1	0.0%	1			1
71	Price)	Ahead Price [per SC, per location]	Zonal Spinning Reserve Capacity Day Ahead Market Clearing Price for Trading Interval		26	0.0%	26			26
72	(DA Price)	Day Ahead Price [per SC, per location]	Zonal Non-Spinning Reserve Capacity Day Ahead Market Clearing Price for Trading Interval		61	0.0%	61			61
81	Price)	Ahead Price [per SC, per location]	Zonal Spinning Reserve Capacity Hour Ahead Market Clearing Price for Trading Interval		2	0.0%	2			2
82	(HA Price)	Hour Ahead Price [per SC, per location]	Zonal Non-Spinning Reserve Capacity Hour Ahead Market Clearing Price for Trading Interval		3	0.0%	3			3
84	(HA Price)	Hour Ahead Price [per SC, per location]	Zonal Replacement Reserve Capacity Hour Ahead Market Clearing Price for Trading Interval		2	0.0%	2			2
111	Spinning Reserve due ISO	Net Reserve Obligation [per SC, per zone]	where		11,629	5.5%	8,722			2,907
112	Non-Spinning Reserve due ISO	Net Reserve Obligation [per SC, per zone]	where		11,497	5.5%	8,623			2,874
114	Replacement Reserve due ISO	Net Reserve Obligation [per SC, per zone]	where		9,796	4.7%	7,347			2,449
115	Regulation Up due ISO	Net Reserve Obligation [per SC, per zone]	where		11,306	5.4%	8,480			2,827
116	Regulation Down due ISO	Net Reserve Obligation [per SC, per zone]	where		11,342	5.4%	8,507			2,836
117	Demand Relief Monthly Capacity Charge	Control Area [per SC]	Total capacity payments for DRP / Total Metered Demand in Control Area		172	0.1%	6			172
124	Capacity Withhold	Location]	dispatched by ISO [per SC, per region]		6	0.0%	6			6
141	No Pay Charge - Spinning Reserve	Location]	User Rate for Replacement Reserve in the Region (i.e. price for CT114)		1,384	0.7%	1,384			1,384
142	No Pay Charge - Non-Spinning Reserve	Per Location]	multiplying with the corresponding MCP for Spin Reserve.		690	0.3%	690			690
144	No Pay Charge - Replacement Reserve	SC, Per Location]	multiplying with the corresponding MCP for Non-Spin Reserve.		153	0.1%	153			153
145	Non-Compliance Charge for Regulation Up	Unavailable A/S Capacity [per SC, per location]	prorating the billable quantity between DA and HA markets and multiplying with the		1,322	0.6%	1,322			1,322
146	Non-Compliance Charge for Regulation Down	Unavailable A/S Capacity [per SC, per location]	prorating the billable quantity between DA and HA markets and multiplying with the		1,403	0.7%	1,403			1,403
203	Day-Ahead Inter-Zonal Congestion Settlement	SC's Day-Ahead net New Firm Use (NFW) import into a Zone [per SC, per Zone]	Price = Day-Ahead Zonal MCP (Reference Price, I)		6,932	3.3%	6,932			6,932
204	due TO	NFW loading [per SC, per Branch Group]	Price = Day-Ahead Congestion Price of Branch Group (Shadow Price, m)		2,608	1.2%	2,608			2,608
253	Hour-Ahead Inter-Zonal Congestion	Zone]	Price = Hour-Ahead Zonal MCP (Reference Price, I)		5,739	2.7%	5,739			5,739
254	due TO	Branch Group NFW loading from Day-Ahead to Hour-Ahead [per SC, per Branch Group]	Price = Hour-Ahead Congestion Price of Branch Group location (Shadow Price, m)		2,020	1.0%	2,020			2,020
255	Hour-Ahead Inter-Zonal Congestion Debit to TOs	Branch Group NFW loading from Dayahead to Hourahead [per SC, per Branch Group]	Price = Day-Ahead Congestion Price of Branch Group (Shadow Price, m)		493	0.2%	493			493
302	Supplemental Reactive Power due SC	Group]	Path) / Total DA Path Flow in the Congested Direction		1,203	0.6%	1,203			1,203
372	High Voltage Access Charge due SC	Transmission Owner's area [per Transmission Owner]	N/A; Set to 1		12	0.0%	12			12
374	High Voltage Access Revenue due PTO	Proportionality, and Burden Caps [per SC, per TAC Area]	Please refer to ISO Tariff 7.1.3 and Section 10 of Appendix F Schedule 3		84	0.0%	84			84
382	High Voltage Wheeling Charge due ISO	location]	rate if there are multiple owners from different TAC areas		60	0.0%	60			60
383	Low Voltage Wheeling Charge due ISO	location]	weighted Low Voltage Access rate if there are multiple owners		408	0.2%	408			408
384	High Voltage Wheeling Revenue due TO	percentage [per TO, per location]	rate if there are multiple owners from different TAC areas		69	0.0%	69			69
385	Low Voltage Wheeling Revenue due TO	percentage [per TO, per location]	weighted Low Voltage Access rate if there are multiple owners		65	0.0%	65			65
401	Insulted Energy	Per Location/interchange]. Insulted energy is settled in the following sequence:	(+ve Suppl. Inbal. Energy * INC MCP) +		35	0.0%	35			35
406	SC Unaccounted for Energy (U/E-Logical)	U/E Quantity [per SC, per Zone]	Price = Amount Due / Billable Qty		4,553	2.2%	2,277			2,277
					13,560	6.5%	6,790			6,790

Charge Type

Have excluded these from analysis subject to further investigation

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Proposed Agenda
2004 GMC Rate Structure Project
Wednesday, May 28, 2003
1:30 p.m. to 3:30 p.m.

Exh. No. ISO- 288, Page 1 of 5

Conference Call-in #1-888-788-6681 Passcode: 98563

1. Introductions/roll call
2. SCE proposal update
3. MID proposal update
4. ISO proposal update
 - a. Initial review of data and calculations
 - b. Implementation of Settlements, Metering and Client Relations cost recovery
 - c. Application of CRS charge to Standby Tariff NCP
5. Bill impact analysis
6. Initial discussion of scheduling activities
7. Initial review of Appendix B issues
8. Discussion of timeline

Notes and list of attendees follow:

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There was some agreement that this delay was a good thing. There was some concern over the exact nature of what the change would mean.

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At this point, Bert Hansen was asked if SCE had any updates to their proposal. Bert noted that SCE was still studying the FERC Order to see if they needed to make changes for consistency.

Laurence Kirsch recapped the changes that MID was making in its proposal. He stated that there would be two options for the Resolving Energy Imbalances charge, options A and B. Option A would have a demand charge. Option B would not. Laurence also noted that MID was dropping the ISO's Forward Scheduling charge as it was unclear what the ISO was using as the billing determinant for this being covered by the charge.

The ISO gave an update on its initial review of data and calculations. The ISO had found some duplicate data and reviewed the listing of SC IDs. This “cleaned-upped” data was used to develop the bill impact analysis that would be reviewed later in the call.

Cathy Yap and Barbara Barkovich discussed how they had associated Settlements, Metering and Client Relations (formerly Customer Service) costs to the other billing determinants. There was a flat \$500 per month SC ID charge and the remaining costs would be recovered from the other billing determinants. The association used the occurrence of charge types in the ISO's Settlements system. This review led to associations of 59 percent to Energy and Transmission Services, 9 percent to

Congestion Management and 32 percent to Market Usage. No costs were associated with Core Reliability Services or Scheduling because these are new charges and the ISO did not want to increase the bill impacts of these charges.

There was a discussion of how Barkovich and Yap had developed their association. There appeared to be some agreement on the method, but that specific associations needed explanation. Also, most parties reserved final judgment until they had more time to review the method.

David Cohen offered to work on an alternative customer charge that would recover more of the Settlements, Metering and Client Relations costs. He implied that this method would involve a tiered customer charge.

Peter Kissel asked if the ISO had done a study to justify the \$500 monthly fee. The ISO had not, but that the \$500 monthly fee was justified, as what Client Relations thought would retain less active SCs and discourage "fly by night" operations. Barbara Barkovich went through the options for recovery of these costs and how they and the ISO determined that a single, flat monthly charge would not be viable.

Jingchao Mi asked why these costs could not be directly assigned to the various functions. Barbara Barkovich noted that these costs were being recovered from those billing determinants, but that the Settlements, Metering and Client Relations function was distinct and separate from the other functions. Cathy Yap emphasized that the functionalization was correct, but that bill impacts required an alternative method of cost recovery.

The ISO asked for a response from participants on whether they thought this cost association method was reasonable or viable. David Cohen stated that the method could be maintained, but that the \$500 monthly fee was too low. He also stated that this method offered a greater level of detail than the ISO had previously provided. Sean Neal stated that MID needed to take this under advisement and spend some time looking more closely at the method. Peter Kissel expressed CDWR's appreciation, but echoed Sean Neal's comments.

The next topic of discussion was the method of assessing Core Reliability Services costs on behind the meter load under Standby Tariffs. Ben Arikawa reviewed the method for participants. He clarified that the ISO had not and would not be assessing a charge on QFs in general, but that the charge would be on those entities with Standby contracts with the IOUs. The proposed method used the contract capacity under Standby agreements shown in Jim Price's testimony in the 2001 GMC proceeding. An effective demand factor would be applied to this contract capacity to derive the expected value of standby load appearing on the ISO grid. The ISO used the effective demand factors developed by SCE in its current GRC filing. The ISO also showed the reduction in assessment from using this method relative to what is currently assessed.

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Katie Kaplan was concerned that the ISO was not relying on the best data for its method, though at first blush, she did not have problems with the methodology. She expressed concern that the method might not be appropriate for intermittent resources as the contract capacity would be higher than the resource would ever operate.

There were questions about the ISO's openness to using more updated data or using data supplied by the entities other than the IOUs. The ISO responded that it was open to receiving data from different sources and was not locked into the numbers shown.

The ISO pointed out that it also needed to develop a measure of the NCP of behind the meter load of governmental entities. However, that method had not yet been developed. There was some concern that the method for governmental entities be consistent with that for entities under Standby agreements. The ISO noted that QFs, cogen or self-gen were fundamentally different from integrated utilities and therefore the treatment of such did not need to be identical.

As time was short, the ISO noted that it would have a discussion of scheduling activities and an initial review of Appendix B issues at the meeting on June 4th.

List of Persons on May 28th Conference Call

Last Name	First	Company	Telephone	E-mail Address
Aoki	Rod	CAC	(415) 421-4143	rsa@a-klaw.com
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Barkovich	Barbara	Barkovich and Yap		
Bonaly	David	CDWR	(916) 653-6241	bonaly@water.ca.gov
Bray	Peter	PG&E		
Brommer	Mike	TID	(209) 883-8320	mtbrommer@tid.org
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Hansen	Bert	SCE	(626) 302-3649	berton.hansen@sce.com
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Kargoll	Robert	PG&E	(415) 973-4001	reke@pge.com
Kirsch	Laurence	Christensen Associates	(415) 663-8608	lkirsch@lrca.com
Kissel	Peter	CDWR		
Lam	Tony	EOB	(916) 322-8632	tlam@eob.ca.gov
Leiber	Phil	ISO	(916) 351-2168	pleiber@caiso.com
LeVine	Debi	ISO	(916) 351-2144	dlevine@caiso.com
Lyon	Deane	ISO	(916) 351-2428	dlyon@caiso.com
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Peterson	Mike	ISO	(916) 608-5896	mpeterson@caiso.com
Pritchard	Jan	MID	(209) 526-7490	janp@mid.org
Regan	William	ISO	(916) 351-4450	wregan@caiso.com
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Springer	John	ISO		jspringer@caiso.com
Terry	Lee	CDWR	(916) 654-3327	lterry@water.ca.gov
Timson	David	ISO		dtimson@caiso.com
Withrow	David	ISO	(916) 608-7134	dwithrow@caiso.com
Yap	Catherine	Barkovich and Yap		

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There were questions about the ISO's openness to using more updated data or using data supplied by the entities other than the IOUs. The ISO responded that it was open to receiving data from different sources and was not locked into the numbers shown.

The ISO pointed out that it also needed to develop a measure of the NCP of behind the meter load of governmental entities. However, that method had not yet been developed. There was some concern that the method for governmental entities be consistent with that for entities under Standby agreements. The ISO noted that QFs, cogen or self-gen were fundamentally different from integrated utilities and therefore the treatment of such did not need to be identical.

As time was short, the ISO noted that it would have a discussion of scheduling activities and an initial review of Appendix B issues at the meeting on June 4th.

List of Persons on May 28 th Conference Call				
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Yap	Catherine	Barkovich and Yap		

Created by: Ben Arikawa

CAISO

LSUPDT: 06/25/03

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Updated Modesto Rate Design Proposal 05-29-03.txt

From: lkirsch@svn.net
Sent: Thursday, May 29, 2003 11:21 AM
To: Arikawa, Ben
Cc: Pritchard, Jan; Neal, Sean; rchemphill@lrca.com
Subject: Updated Modesto Rate Design Proposal

Ben:

The updated write-up is attached, and can be distributed as you think appropriate.

Laurence

Laurence D. Kirsch
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Please visit our website at WWW.LRCA.COM

California ISO

BUS	ASSOC ID	SHORT NAME	NAME	CLASS
4553	ALLG	Allegheny Energy Supply Company, LLC		3
3001	AEP1	American Electric Power Service Corp		3
2408	AEPS	American Electric Power Service Corporation		3
2149	AQPC	Aquila Power Corporation		3
3371	AZCO	Arizona Electric Power Cooperative, Inc.		3
1011	APS1	Arizona Public Service Company-APS1		3
4976	APS4	Arizona Public Service Company-APS4		3
3751	APX3	Automated Power Exchange Inc-APX3		3
1020	APX1	Automated Power Exchange, Inc-APX1		3
3992	APX4	Automated Power Exchange-APX4		3
4239	APX5	Automated Power Exchange-APX5		3
4774	APX6	Automated Power Exchange-APX6		3
4833	APX7	Automated Power Exchange-APX7		3
3451	AVA1	AVISTA CORPORATION		3
1648	AEI1	Avista Energy Inc		3
1227	BPA1	Bonneville Power Administration		3
3112	PWRX	British Columbia Power Exchange		3
4793	PWR2	British Columbia Power Exchange - PWR2		3
1528	BCHA	British Columbia Power Exchange Corporation		3
3951	CMWD	Calif. Department of Water Resources		2
3652	CERS	California Department of Water Res.		2
1088	CDWR	California Department of Water Resources		2
1023	CAPP	California Polar Power Brokers LLC		3
1247	PXC1	California Power Exchange		3
3335	PXC2	California Power Exchange 2		3
3336	PXC3	California Power Exchange 3		3
3553	PXC4	California Power Exchange 4		3
3571	PXC5	California Power Exchange 5		3
3632	PXC6	California Power Exchange 6		3
3572	CALP	Calpine Energy Services		3
3211	CAL1	Cargill Alliant, LLC		3
5056	CEPL	Citadel Energy Products LLC		3
1168	CPS1	Citizens Power Sales		3
1708	ANHM	City of Anaheim		2
5018	TO09	City of Anaheim - PTO		2
1868	AZUA	City of Azusa		2
4996	TO06	City of Azusa - PTO		2
1869	BAN1	City of Banning		2
5016	TO07	City of Banning - PTO		2
3431	BURB	City of Burbank, Public Service Department		3
1628	GLEN	City of Glendale		3
1688	PASA	City of Pasadena		2
1107	RVSD	City of Riverside		2
5021	TO08	City of Riverside - PTO		2
1630	SNCL	City of Santa Clara, dba Silicon Valley Power		2
1008	VERN	City of Vernon		2
5019	TO10	City of Vernon - PTO		2

3471	CRSP	Colorado River Storage Project	2
3712	CONN	Conectiv Energy Supply, Inc.	3
4956	CNCO	ConocoPhillips Company	3
3251	CPSI	Constellation - DO NOT USE	3
4894	HDPP	Constellation Power Source - HDPP	3
3271	CPSC	Constellation Power Source Inc.	3
2770	CRLP	Coral Power, LLC	3
1021	DETM	Duke Energy Trading and Marketing, L.L.C.	3
1024	ECH1	Dynegy Power Marketing, Inc.	3
2509	EMMT	Edison Mission Marketing & Trading, Inc.	3
1004	ESRC	Edison Source	3
2590	EPE1	El Paso Electric Company	3
4434	ELPM	El Paso Merchant Energy	3
4513	ELPE	El Paso Merchant Energy - ELPE	3
4256	EPME	El Paso Merchant Energy, L.P.	3
2289	EPPS	El Paso Power Services Company	3
2369	EESI	Enron Energy Services, Inc.	3
1005	EPMI	ENRON Power Marketing Inc	3
4494	ENRJ	ENRON POWER MARKETING, INC.	3
3711	EWEB	Eugene Water and Electric Board	3
4673	EXPT	Exelon Generation	3
1588	HFET	HAFSLUND ENERGY TRADING L.L.C.	3
4113	IDAC	IDACORP Energy, L.P.	3
1668	IPC1	Idaho Power Company	3
1249	IEPI	Illinova Energy Partners, Inc	3
2999	KET3	Koch Energy Trading	3
1189	LDWP	Los Angeles Water & Power	2
1009	LGE1	Louisville Gas and Electric Company	3
2910	MEGA	Merchant Energy Group of the Americas, INC	3
3611	MERL	Merrill Lynch Capital Services	3
4813	MWSC	Midway Sunset Cogeneration Company	3
2429	MIEC	Mieco, Inc.	3
1026	SCEM	Mirant	3
4654	MAEM	Mirant Inc.	3
1308	MID1	Modesto Irrigation District	2
2998	MSCG	Morgan Stanley Capital Group, Inc.	3
1750	NEVP	Nevada Power Company	3
3011	NEI1	NewEnergy Inc.	3
1010	NCPA	Northern California Power Agency	2
3935	TO05	Pacific Gas & Electric Com	1
3931	PGAB	PACIFIC GAS & ELECTRIC COM.	2
3932	PCGB	PACIFIC GAS & ELECTRIC COMP	1
5057	PCG2	Pacific Gas & Electric Company-PCG2	2
1187	TO01	Pacific Gas and Electric Co	1
1015	PGAE	Pacific Gas and Electric Company	2
3771	PCG1	Pacific Gas and Electric Company,	1
1006	PAC1	PacificCorp	3
3174	PCPM	PacifiCorp Power Marketing Inc.	3
3573	PAC3	PacifiCorp-Green	3
2918	PECO	PECO Energy Company	3
1017	PGES	PG & E Energy Services	3
4032	PGET	PG&E Energy Trading	3

2830	PETP	PG&E Energy Trading Power, L.P.	3
3933	COTB	PGAE & COTB	2
1147	COTP	PGAE & COTP	2
1016	PORT	Portland General Electric Company	3
1067	PRM1	Power Resource Managers, L.L.C.	3
3191	PPLM	PP&L MONTANA, LLC	3
3231	PSCO	Public Service Company of Colorado	3
1448	PNM1	Public Service Company of New Mexico	3
3391	GCPD	Public Utility District No. 2 of Grant County	3
3131	PSE1	Puget Sound Energy	3
1068	NES1	Reliant Energy Services, Inc.	3
4853	RWET	RWE Trading Americas Inc.	3
2995	SMUD	Sacramento Municipal Utility District	2
1012	SRP1	Salt River Project	3
1188	TO02	San Diego Gas & Electric Co.	1
3511	SDG3	San Diego Gas & Electric, Merchant	3
1007	SDGE	San Diego Gas and Electric Company	1
3811	SDG4	San Diego Gas and Electric, Merchant	3
1029	SCL1	Seattle City Light	3
3531	SEES	Sempra Energy Solutions	3
1022	SETC	Sempra Energy Trading Corporation	3
3333	SPPC	Sierra Pacific Power Company	3
4713	SCE5	Southern California Edison (5)	2
1268	SCE2	Southern California Edison Co	2
1207	TO03	Southern California Edison Co.	1
1014	SCE1	Southern California Edison Company	1
5076	SCE6	Southern California Edison-SCE6	1
5077	SCE7	Southern California Edison-SCE7	1
2997	SET1	Statoil Energy Trading Inc.	3
4072	SEL2	Strategic Energy LLC	3
2890	SEL1	Strategic Energy, LLC	3
1769	TCL1	Tacoma City Light	3
4473	TEND	TenderLand Power Company	3
4573	TEMU	TransAlta Energy Marketing (U.S.) Inc	3
3392	TRAL	Transalta Energy Marketing Inc.	3
3000	RNT3	Transmission Agency of Northern California	2
1488	TEP1	Tucson Electric Power	3
3591	TID1	Turlock Irrigation District,	2
4873	TXUE	TXU Energy Trading	3
4693	UBSW	UBS AG	3
3911	VSYN	VIASYN, INC	3
1013	VGE1	Vitol Gas and Electric LLC	3
1770	WALC	Western Area Lower Colorado	2
4896	WCSL	Western Area Power Admin. - City of Shasta Lake	2
4897	WEPA	Western Area Power Admin.-Eastside Power Aut	2
3952	WRDG	Western Area Power Admin.-Redding	2
1127	WAMP	Western Area Power Administration	2
4237	WDOE	Western Area Power Admin-WDOE	2
5037	WEMT	Williams Energy Marketing & Trading-WEMT	3
1167	WESC	Williams Energy Marketing and Trading	3

California ISO															Market Participant Category															SC Categories															Comments														
BAID		Acronym/SCID		NAME		BA TYPE		PTO		SC		NMP		IOU		Muni - GE		Generator		Other SC		Market/Broker		Comments																																			
														1		2				3																																							

California ISO									
BAID BUS_ASSOC_ID	Acronym/SCID SHORT_NAME	NAME	Market Participant Category				SC Categories		
			BA TYPE	PTO	SC	NMP	IOU	Muni - GE	Generator
									Other SC Marketer/Broker
2770	CRLP	Coral Power, LLC					1	2	3
1021	DETM	Duke Energy Trading and Marketing, L.L.C.	SF		SC				1
1024	ECH1	Dynegy Power Marketing, Inc.	SF		SC				1
2509	EMMT	Edison Mission Marketing & Trading, Inc.	S		SC				1
1004	ESRC	Edison Source	S		SC				1
2590	EPE1	El Paso Electric Company	N			NMP			1
4434	ELPM	El Paso Merchant Energy	SI		MULT				1
4573	ELPE	El Paso Merchant Energy - ELPE	SI		MULT				1
4256	EPME	El Paso Merchant Energy, L.P.	SIF		MULT				1
2289	EPFS	El Paso Power Services Company	SI		SC				1
2369	EESI	Enron Energy Services, Inc.	SIF		Inactive				1
1005	EPMI	ENRON Power Marketing Inc	SF		SC				1
4494	ENRJ	ENRON POWER MARKETING, INC.	SF		MULT				1
3711	EWEB	Eugene Water and Electric Board	N			NMP			1
4673	EXPT	Exelon Generation	SF		SC				1
1588	HFET	HAFSLUND ENERGY TRADING L.L.C.	S		Inactive				1
4113	IDAC	IDACORP Energy, L.P.	SF		MULT				1
1668	IPC1	Idaho Power Company	SF		SC				1
1249	IEPI	Illinova Energy Partners, Inc	S		Inactive				1
2999	KET3	Koch Energy Trading	SIF		SC				1
1189	LDWP	Los Angeles Water & Power	SI		Inactive		1		1
1009	LGE1	Louisville Gas and Electric Company	S		Inactive				1
2910	MEGA	Merchant Energy Group of the Americas, INC.	SIF		SC				1
3611	MERL	Merrill Lynch Capital Services	SIF		SC				1
4813	MWSC	Midway Sunset Cogeneration Company	SI		SC			1	1
2429	MIEC	Mieco, Inc.	SI		SC				1
1026	SCEM	Mirant	SF		MULT				1
4654	MAEM	Mirant, Inc.	SF		SC				1
1308	MID1	Modesto Irrigation District	SF		SC			1	1
2998	MSCG	Morgan Stanley Capital Group, Inc.	SF		SC				1
1750	NEVP	Nevada Power Company	N			NMP			1
3011	NE11	NewEnergy Inc.	SF		SC				1
1010	NCPA	Northern California Power Agency	S		SC			1	1
3935	TO05	Pacific Gas & Electric Com	TU	MULT			1		
3931	PGAB	PACIFIC GAS & ELECTRIC COM.	SF		MULT			1	
3932	PCGB	PACIFIC GAS & ELECTRIC COMP	S		MULT			1	
5057	PCG2	Pacific Gas & Electric Company-PCG2	SF		MULT				
1187	TO01	Pacific Gas and Electric Co	TU	PTO			1		
1015	PGAE	Pacific Gas and Electric Company	SF		SC			1	
3771	PCG1	Pacific Gas and Electric Company,	S		MULT		1		
1006	PAC1	PacificCorp	S		SC				1
3174	PCPM	PacificCorp Power Marketing Inc.	S		SC				1
3573	PAC3	PacificCorp-Green	S		MULT				1
2918	PECO	PECO Energy Company	SIF		SC				1
1017	PGES	PG & E Energy Services	SF		Inactive				1
4032	PGET	PG&E Energy Trading	SF		MULT				1
2830	PETP	PG&E Energy Trading Power, L.P.	SF		SC				1
3933	COTB	PGAE & COTB	S		MULT			1	
									Schedules ETCs. Could be classified as IOU or Muni/GE.

California ISO										Market Participant Category										SC Categories																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																															

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Scheduling coordinators were assigned to these classifications as indicated below:

Company	Grp	Desc
SCE (LADWP/Mojave)	n/a	Government Entity
SDG&E (PV/APS/IID)	n/a	
CDWR	GE	
PGAE & COTP	GE	
PG&E	GE	
SCE (Other Muni)	GE	
SDG&E (other Muni)	GE	
WAPA	GE	
Anaheim	GE	
APS (various)	GE	
Azuza	GE	Other Scheduling Coordinators
Banning	GE	
Cal PX (Tracy load)	GE	
Illinova (Bear Valley)	GE	
Pasadena	GE	
Riverside	GE	
Sempra (Vista load)	GE	
Vernon	GE	
American Elec Pwr	SC	
Aquila Power	SC	
Avista	SC	
Brit Columbia Pwr	SC	
BC Hydro	SC	
BPA	SC	
Calif Polar Pwr	SC	
Citizens Pwr Sales	SC	
City of Seattle	SC	
Coral Power LLC	SC	
Edison Mission Mktg	SC	
Edison Source	SC	
Idaho Power	SC	
LADWP	SC	
Mieco	SC	
Modesto	SC	
Montana Power	SC	
NCPA	SC	

PacificCorp	SC	
Public Serv of NM	SC	
Puget Sound Energy	SC	
Portland General	SC	
Sempra Energy Trdg	SC	
Rounding & Other	SC	
Arizona Public Svcs	SC	
ENRON Power Mktg	SC	
Illinova	SC	
LG&E	SC	
PG&E Energy Svcs	SC	
Salt River Project	SC	
Cal PX	SC	Scheduling Coordinator
QFs	QF	Qualified Facilities
APX	Mkt	Marketers
Duke Energy Trdg	Mkt	
Dynergy Power Mktg	Mkt	
Reliant Energy	Mkt	
South Co Energy Mktg	Mkt	
Williams Energy Svcs	Mkt	

The distinction between Marketers and Other SCs is not meaningful.

The ISO has suggested that, based on a discussion between ISO staff and CPUC/EOB, staff Four classifications could be of use:

1. IOUs
2. GEs
3. QF load
4. Other Scheduling Coordinators

Proposed Agenda
2004 GMC Rate Structure Project
California ISO, Folsom
Wednesday, June 4, 2003
9:00 p.m. to 3:00 p.m.

Exh. No. ISO- 292, Page 1 of 1

Public Session

Conference Call-in #1-888-788-6681 Passcode: 98563

1. Introductions/roll call
2. Discussion of June 6 Board Presentation
3. Initial review of Appendix B issues
4. Initial review of billing determinant stability
5. SCE proposal update
6. MID proposal update
 - a. Development of tiered rates
 - b. New portions of proposal
7. ISO proposal update
 - a. Behind the meter load NCP
 - b. Discussion of scheduling activities
 - c. Discussion of functional association of Settlements, Metering and Client Relations costs
 - d. Discussion of cost assignment method (if time permits)

Confidential Session

1. Bill impact analysis
2. Discussion of cost assignment method (if time permits)

Update on Modesto's GMC Proposal

**Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.
www.LRCA.com**

CAISO 2004 GMC Rate Design Project Meeting

**Folsom, California
June 4, 2003**



**CHRISTENSEN
ASSOCIATES**

Recent Changes

1. Abandon the ISO's Forward Scheduling Service Charge
 - We are concerned about the relevance of its billing determinant to the ISO's costs of arranging schedules
2. Offer two options for measuring customers' use of the Managing Transmission Flows function
 - Option A: Include a demand charge
 - Option B: Exclude a demand charge

Arguments for Option A:

Including a Demand Charge

- Managing Transmission Flows is a service that only the ISO can provide.
- It may be appropriate to recover fixed costs through demand charges.
- The Commission favors an NCP demand charge for some loads.

Arguments for Option B:

Excluding Demand-Side

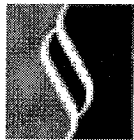
- q ISO costs of Managing Transmission Flows are more related to system complexity than to peak loads.
- q Demand-charge cost recovery may be unrelated to customer cost causations.
- q Cost shifts are smaller.

Our Updated Parameters: Option A

Function	Dollars	Quantity	Rate
Resolving Energy Imbalances			
uninstructed deviation energy			
tier 1	\$315,695	4,873,932 MWh	\$0.0648 /MWh of 1st 5 MWh of net deviation
tier 2	\$14,077,705	11,577,685 MWh	\$1.2159 /MWh of over 5 MWh of net deviation
uninstructed deviation demand			
tier 1	\$55,816	3,806 MW-months	\$14.66 /MW-month of 1st 5 MW INCP net deviation
tier 2	\$27,788,773	46,319 MW-months	\$599.94 /MW-month of over 5 MW INCP net deviation
number of SCs	\$195,250	1,562 SC-months	\$125 /SC-month
	\$42,433,238		
Managing Transmission Flows			
power withdrawals	\$43,519,838	242,456,619 MWh	\$0.1795 /MWh net load
maximum power withdrawals	\$84,190,810	534,042 MW-months	\$157.65 /MW-month 12NCP net load
number of SCs	\$585,750	1,562 SC-months	\$375 /SC-month
	\$128,296,398		
Administering Markets			
Energy Trades	\$12,326,784	5,406,097 MWh	\$2.2802 /MWh traded
AS Trades	\$54,543,951	23,921,072 MWh	\$2.2802 /MWh traded
FTR Trades	\$0		
Trading volumes	\$66,870,735		
Totals	\$237,600,371		

Our Updated Parameters: Option B

Function	Dollars	Quantity	Rate
Resolving Energy Imbalances			
Uninstructed deviation energy			
tier 1	\$315,695	4,873,932 MWh	\$0.0648 /MWh of 1st 5 MWh of net deviation
tier 2	\$14,077,705	11,577,685 MWh	\$1.2159 /MWh of over 5 MWh of net deviation
Uninstructed deviation demand			
tier 1	\$55,816	3,806 MW-months	\$14.66 /MW-month of 1st 5 MW INCP net deviation
tier 2	\$27,788,773	46,319 MW-months	\$599.94 /MW-month of over 5 MW INCP net deviation
Number of SCs	\$195,250	1,562 SC-months	\$125 /SC-month
	\$42,433,238		
Managing Transmission Flows			
power withdrawals	\$127,710,648	242,456,619 MWh	\$0.5267 /MWh net load
number of SCs	\$585,750	1,562 SC-months	\$375 /SC-month
	\$128,296,398		
Administering Markets			
Energy Trades	\$12,326,784	5,406,097 MWh	\$2.2802 /MWh traded
AS Trades	\$54,543,951	23,921,072 MWh	\$2.2802 /MWh traded
FTR Trades	\$0		
	\$66,870,735		
Totals	\$237,600,371		



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ISO Proposal Update 2004 GMC Rate Structure Project

June 4, 2003

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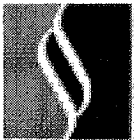
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Topics

- Functionalization
- Billing determinants
- Scheduling Activities
- Functional association of charge types

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Functionalization

- Reliability Services
 - Core Reliability Services
 - Energy and Transmission Services
- Market Services
 - Forward Scheduling
 - Congestion Management
 - Market Usage
- Settlements, Metering, and Client Relations

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Billing Determinants

- Core Reliability Services
 - Non-coincident peak demand monthly by SC ID
 - ISO Tariff requires SCs to submit gross meter data
 - Subject to decision in QF PGA proceeding (ER98-997 - 000)
 - ISO will assume SCs abide by Tariff

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Billing Determinants (cont.)

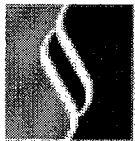
- Energy and Transmission Services
 - ISO “Controlled Grid load plus exports”
 - Slight change numerically from net Control Area load plus exports

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Billing Determinants (cont.)

- Forward Scheduling
 - Number of final Hour-Ahead schedules, not including changes from Day-Ahead schedules
 - Load, generation, import, export, inter SC trades and awarded AS schedules (self and market provided)

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Billing Determinants (cont.)

- Congestion Management
 - Net scheduled Hour-Ahead interzonal flows
 - Charged for each time energy is scheduled across a zonal boundary

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Billing Determinants (cont.)

- Market Services
 - Purchases and sales of Ancillary Services (market only), instructed energy and the absolute value of net uninstructed deviations within an interval by SC ID

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Billing Determinants (cont.)

- Settlements, Metering and Client Relations
 - \$500 per SC ID monthly charge regardless of activity
 - Balance of Settlements, Metering and Client Relations costs recovered by association with other billing determinants

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Scheduling Activities

- Processing charge per final Hour-Ahead schedule
 - Regardless of time of submission, in advance of Day-Ahead, Day-Ahead or Hour-Ahead
- ISO processes schedules to confirm
 - Path ratings are not exceeded
 - Sufficient AS is or will be procured (self or market)
 - Balanced SC portfolio (load and resources)

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Scheduling Activities (cont.)

- All schedules are processed for each hour regardless of time of submission
 - ISO processes each hour of an advanced Day-Ahead schedule and Day-Ahead schedule
 - Software runs discretely for each hour
 - Problems are resolved for each hour
 - ISO also processes each Hour-Ahead schedule by hour
 - ISO re-processes each hour of a Day-Ahead schedule that rolls to the Hour-Ahead (even if unchanged)
- Processing of import and export schedules is in addition to Control Area operations check-ins and check-outs (e.g., E-Tags)

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Functional Association of Charge Types

- Bulk of costs are Settlements related
- B&Y analyzed charge type flows through Settlements System for September 2001 – August 2002
 - Reviewed charge type definitions
- B&Y associated charge type with billing determinants of:
 - Energy and Transmission Services
 - Congestion Management
 - Market Usage

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Next Steps

- Update billing determinants
- Discuss if mitigation is needed
- Other issues
 - 12 NCP vs. 12 CP

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Cost Assignment Methodology 2004 GMC Rate Structure Project June 4, 2003

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Topics

- Interviews/surveys of directs
- Direct Indirects
- Indirects
- Overheads
- Capital

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Interview/Survey Process (Directs)

- Barkovich and Yap led sessions
 - Grid Operations
 - Market Services

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Grid Operations Directs

- Grid Planning
- Outage Coordination
- Loads and Resources
- Grid Operations – Generation and Transmission Dispatchers, Mgmt and Support
- Reliability Coordinators
- Engineering and Maintenance
- Operations Support and Training - General
- Operations Training
- Special Projects Engineering
- Operations Support
- Transmission Maintenance
- Operations Applications Support
- Operations Engineering North
- Operations Engineering South
- Operations Coordination
- Scheduling Dept Director
- Scheduling Support
- Regional Coordination
- Field Data Acquisition (portion)

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Market Services Directs

- Field Data Acquisition (portion)
- Application Support
- Tariff and Contract Implementation (RMR Contracts)
- BBS Settlements – Preliminary Settlements
- BBS Settlements – Final Settlements
- Contracts and Special Projects
- Client Relations
- Manager, Markets
- Market Engineering
- Business Solutions
- Market Quality
- Market Integration
- Market Analysis
- Market Surveillance Committee
- Compliance – General
- Compliance - Audits

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Indirects

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Overheads

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- System applications

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Next Steps

- Formalization of process
- Education of directors and managers

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Initial Review of Appendix B Issues

2004 GMC Rate Structure Project

June 4, 2003

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pleiber@caiso.com

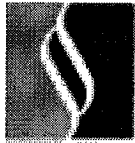
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Appendix B Background

- Part of 2002 GMC Settlement Document
 - Lists milestones and procedures to be addressed in 2004 GMC Rate Structure Project
 - Does not mandate level of review or discussion
 - Does not restrict discussion to those topics listed

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Appendix B Issues

- What are the parameters of the stakeholder process?
 - How are stakeholder comments incorporated?
 - How are confidentiality concerns addressed?
- Issues to be taken into account
 - Review of ISO Budget
 - Principles of rate design

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Appendix B Issues (cont.)

- Milestones
 - Schedule leading to November 2003 filing at FERC
- Issues identified in Initial Decision
 - Dr. Kirsch's proposal
 - CPUC/EOB demand charge
 - Lesser charge on behind the meter load
 - Allocations to cost centers 1424 and 1441
 - Full Review of GMC rate design

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Appendix B Issues (cont.)

- Additional issues
 - GMC structure and MD02 implementation
 - Timing of LMP (need for October 2003 change in rates)
 - Billing determinant change for Congestion Management
 - Effect of LMP on revenue recovery
 - MD02 effect on real time balancing
 - Recovery of MD02 costs
 - Stakeholder Budget process
 - Impact of MSS and new control areas

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Appendix B Issues (cont.)

- Other areas for study
 - Rate structures at other ISOs
 - Further unbundling of CAS
 - Two part rates
 - Alternative tracking and allocation mechanisms
- Use of rate design consultant

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Next Steps

- Development of documentation accounting for the issues addressed
- Other?

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Work in Progress

Preliminary Issues List from Appendix B of 2002 GMC Settlement		
Issue	Resolution	Document
1.1.2. What are the parameters of the stakeholder process? How do we incorporate stakeholder comments?	The issue of the form of the stakeholder process was first brought up at the July 25, 2002 Market Issues Forum meeting. Ben Arikawa gave a presentation concerning the potential stakeholder process. This presentation can be found at: http://www.caiso.com/docs/2002/07/24/200207241455243624.pdf Immediately after Mr. Arikawa's presentation, Byron Woertz gave a presentation discussing a proposed structure for the stakeholder process. This presentation can be found at: http://www.caiso.com/docs/2002/07/25/200207251625493521.pdf	ISO 07/25/02-01
	On August 2, 2002, one week after these presentations, the ISO issued a market notice requesting stakeholder comments on the proposed stakeholder process, whether an advisory committee structure was desirable and what the make-up of the committee should be.	ISO 08/02/02-01
	On August 2, 2002, MID responded to the discussion at the July 25, 2002 Market Issues Forum meeting with a letter addressed to Terry Winter and Charles Robinson concerning their objections to a stakeholder advisory committee format.	MID 08/02/02-02
	On August 7, 2002, David Cohen, representing TANC, transmitted a response to the ISO concerning the composition of the stakeholder advisory group and the	TANC 08/07/02-01

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Last Updated: 06/03/03

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	issues to be discussed under the GMC process.	
	On August 9, 2002, CAC/EPUC responded to the August 2, 2002 market notice. In their response, CAC/EPUC argued against a stakeholder advisory committee format.	CAC 08/09/02-01
	After consideration of the comments received, the ISO issued a market notice on August 16, 2002 outlining a GMC Review Stakeholder Advisory Committee and the process for consideration of changes to the ISO rates. Responses were requested by August 21, 2002. A meeting was scheduled for August 29, 2002.	ISO 08/16/02-01
	E-mail from Lisa Wolfe (EOB) to Byron Woertz regarding Stakeholder Advisory Committee	EOB 08/19/02-01
	E-mail from Katie Kaplan (IEP) to Ben Arikawa indicating the IEP would participate in the generator class	IEP 08/20/02-01
	E-mail from Bert Hansen (SCE) to Ben Arikawa proposing that SCE represent transmission owners	SCE 08/20/02-01
	E-mail from Tony Braun (CMUA) to Ben Arikawa identifying TANC as the potential representative for municipals	CMUA 08/21/02-01
	E-mail from Ed Lucero (SDG&E) to Ben Arikawa identifying issues that should be addressed in the GMC process	SDGE 08/22/02-01
	Market notice concerning August 29, 2002 conference call and agenda	ISO 08/26/02-01 ISO 08/26/02-02
	Conference call August 29, 2002	
	List of participants on August 29, 2002 conference call	ISO 08/29/02-01
	MID letter to ISO concerning MID concerns about the GMC process	MID 08/30/02-01

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Initial Review of Billing Determinant Stability

2004 GMC Rate Structure Project June 4, 2003

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Updated Billing Determinants

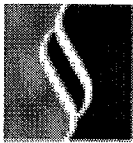
- NCP (net of Mohave exports)
- Net Control Area Load plus exports
- Net HA scheduled interzonal flows
- Net uninstructed deviations
- Sum of the maximum net uninstructed deviations
- Inter SC Trades

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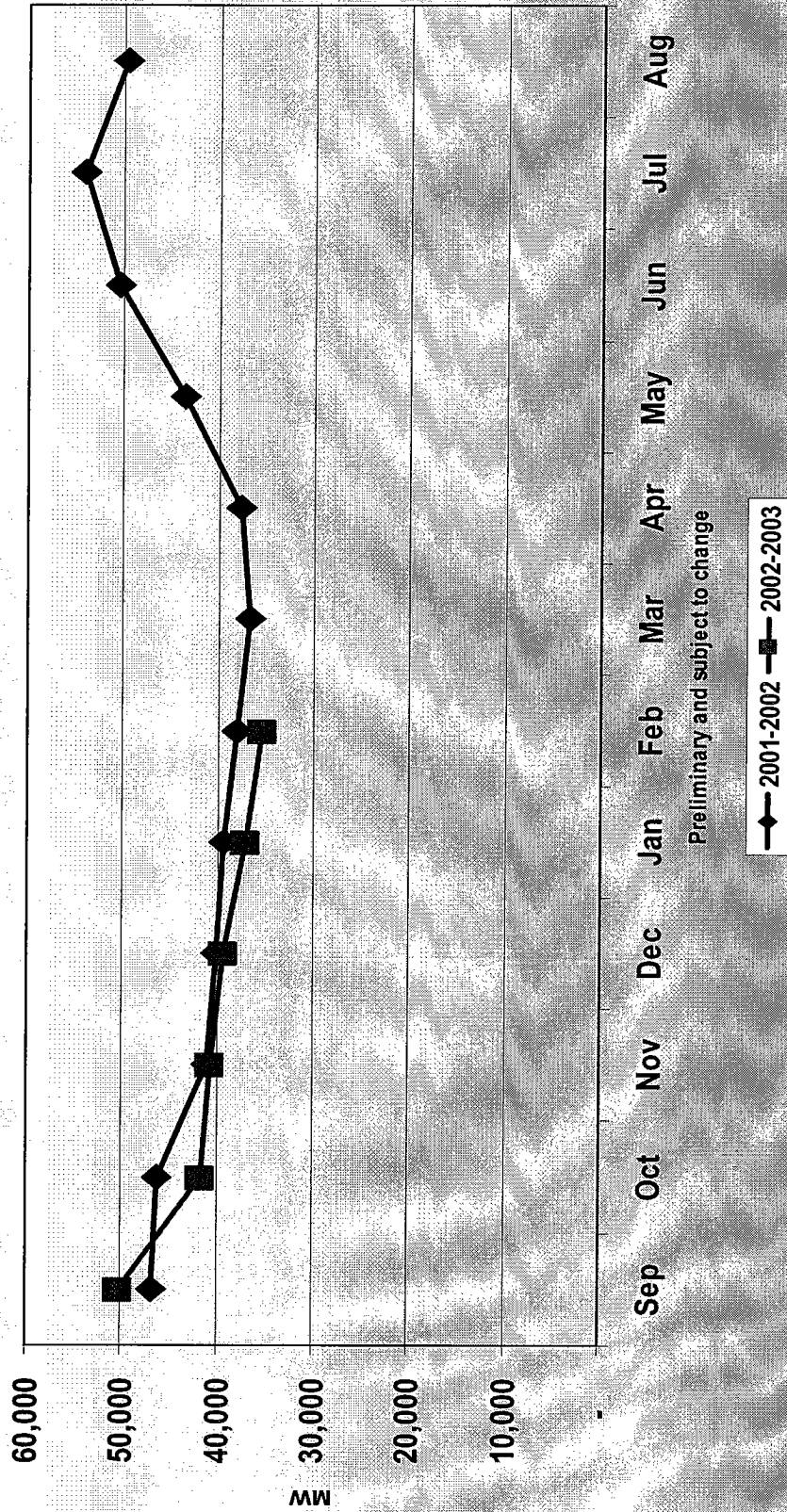
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Comparison of NCP Sept. 2001 through Feb. 2003



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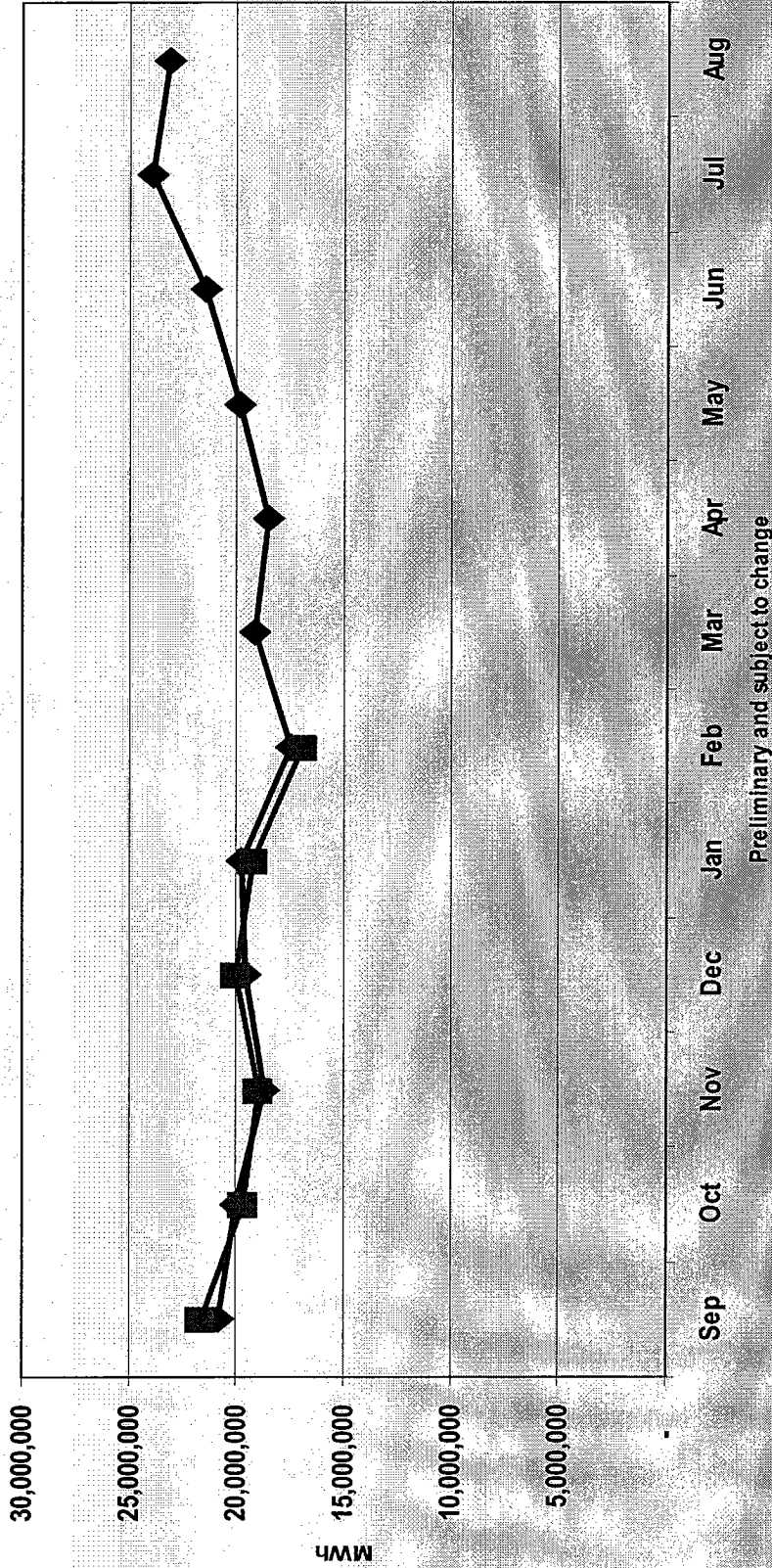
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Comparison of Net Control Area Load Sept. 2001 through Feb. 2003



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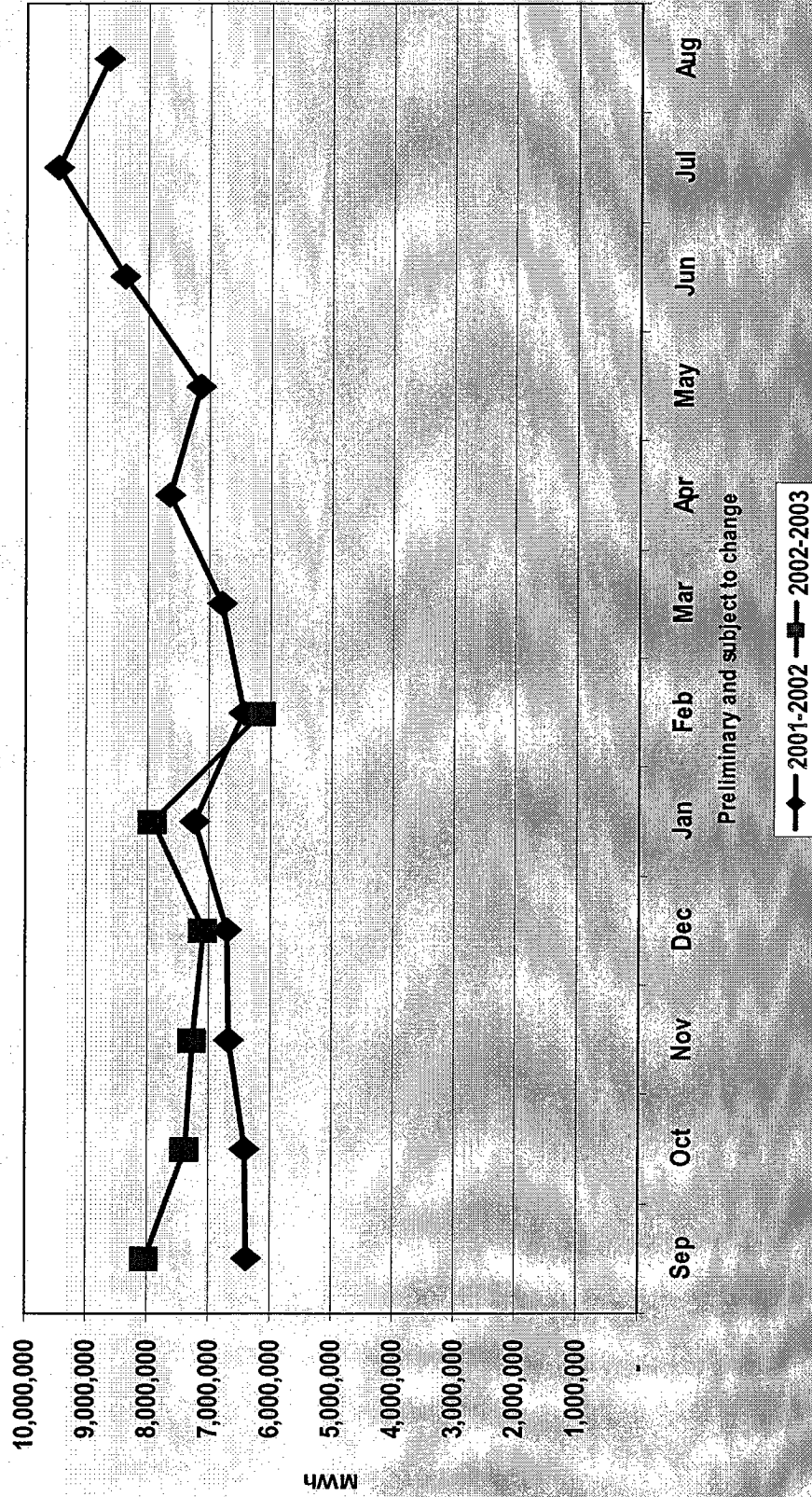
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Comparison of Net HA Scheduled Interzonal Flows Sept. 2001 through Feb. 2003



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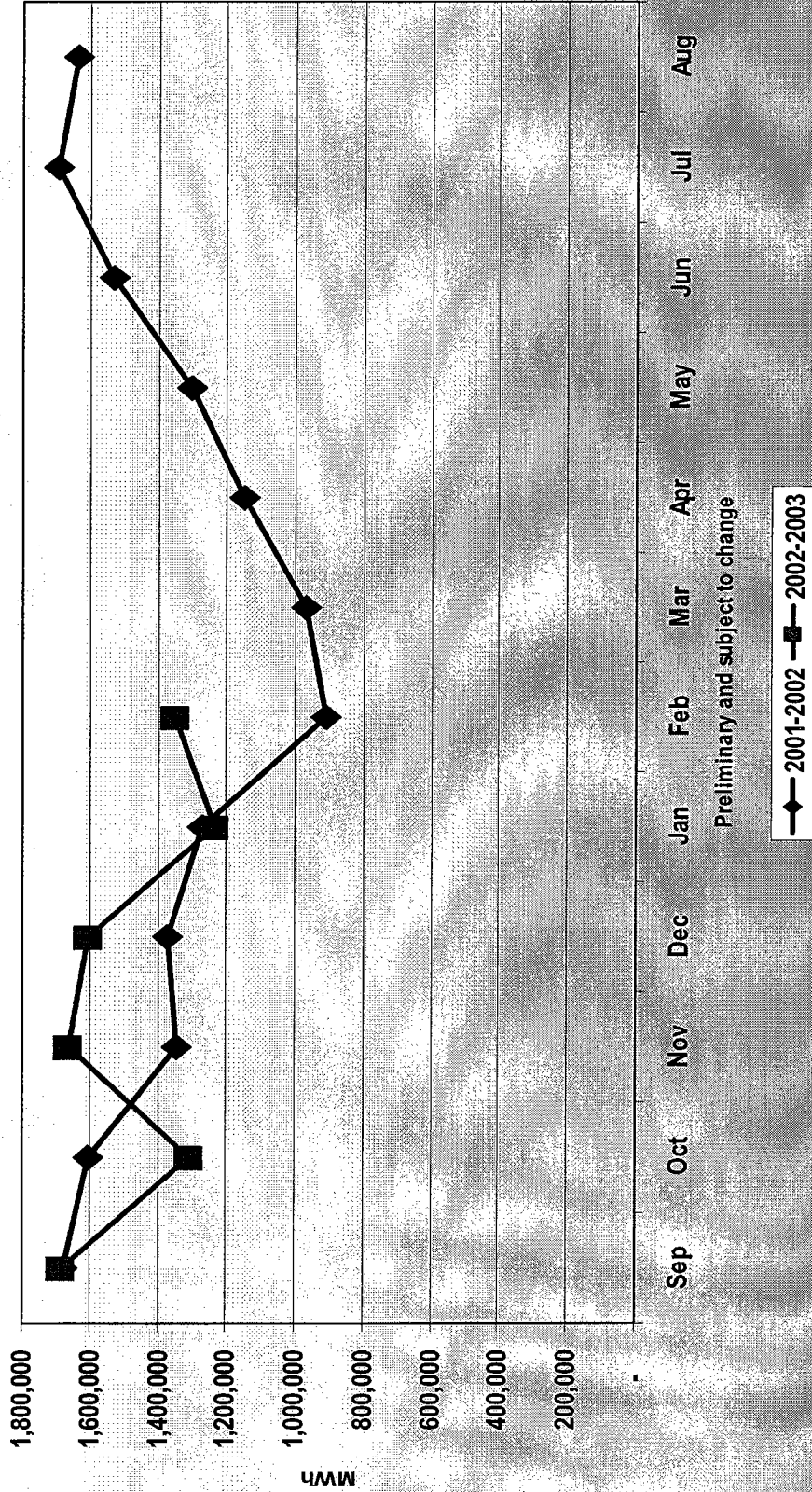


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Comparison of Net Uninstructed Deviations

Sept. 2001 through Feb. 2003



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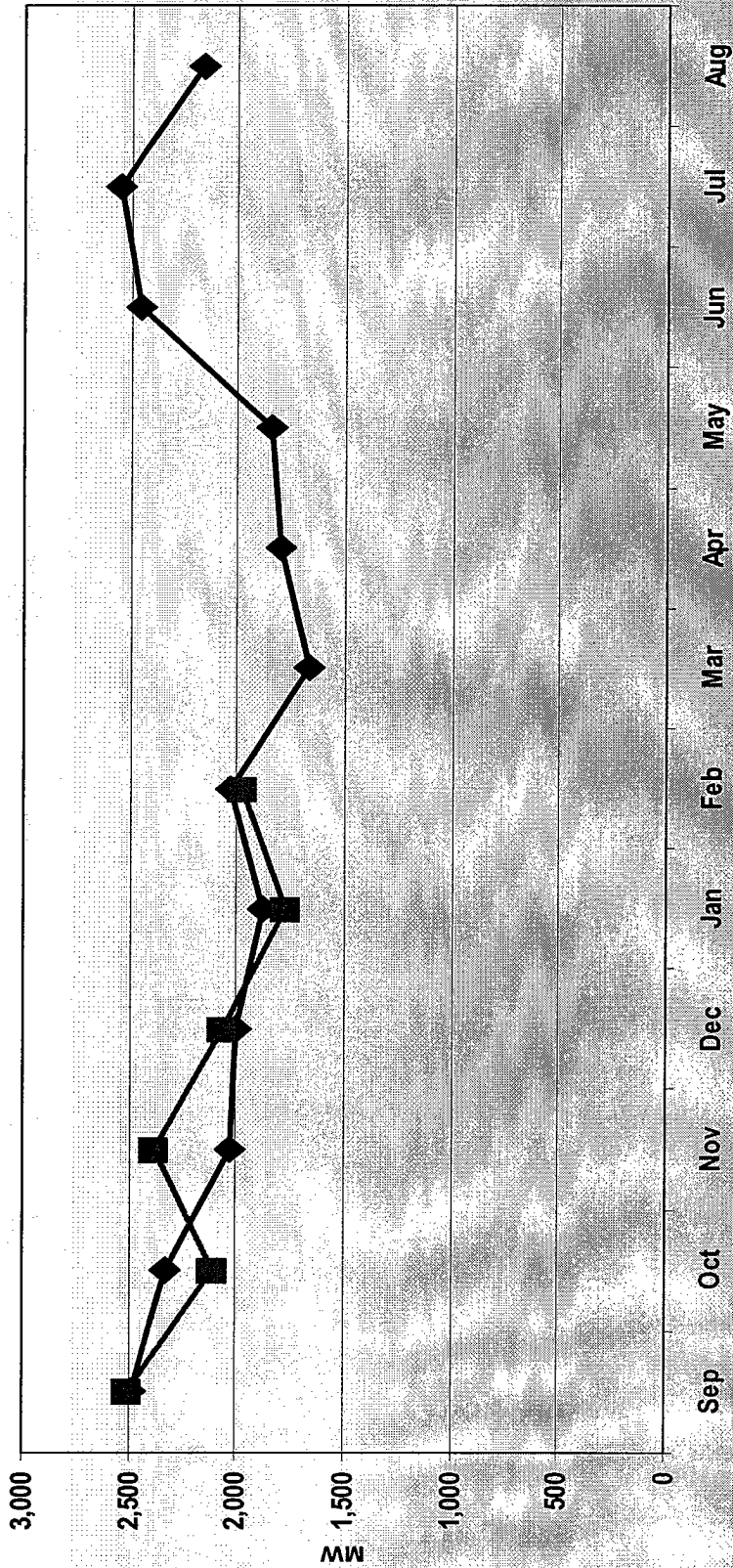
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Comparison of the Sum of the Maximum Net Uninstructed Deviations Sept. 2001 through Feb. 2003



Preliminary and subject to change

◆ 2001-2002 ■ 2002-2003

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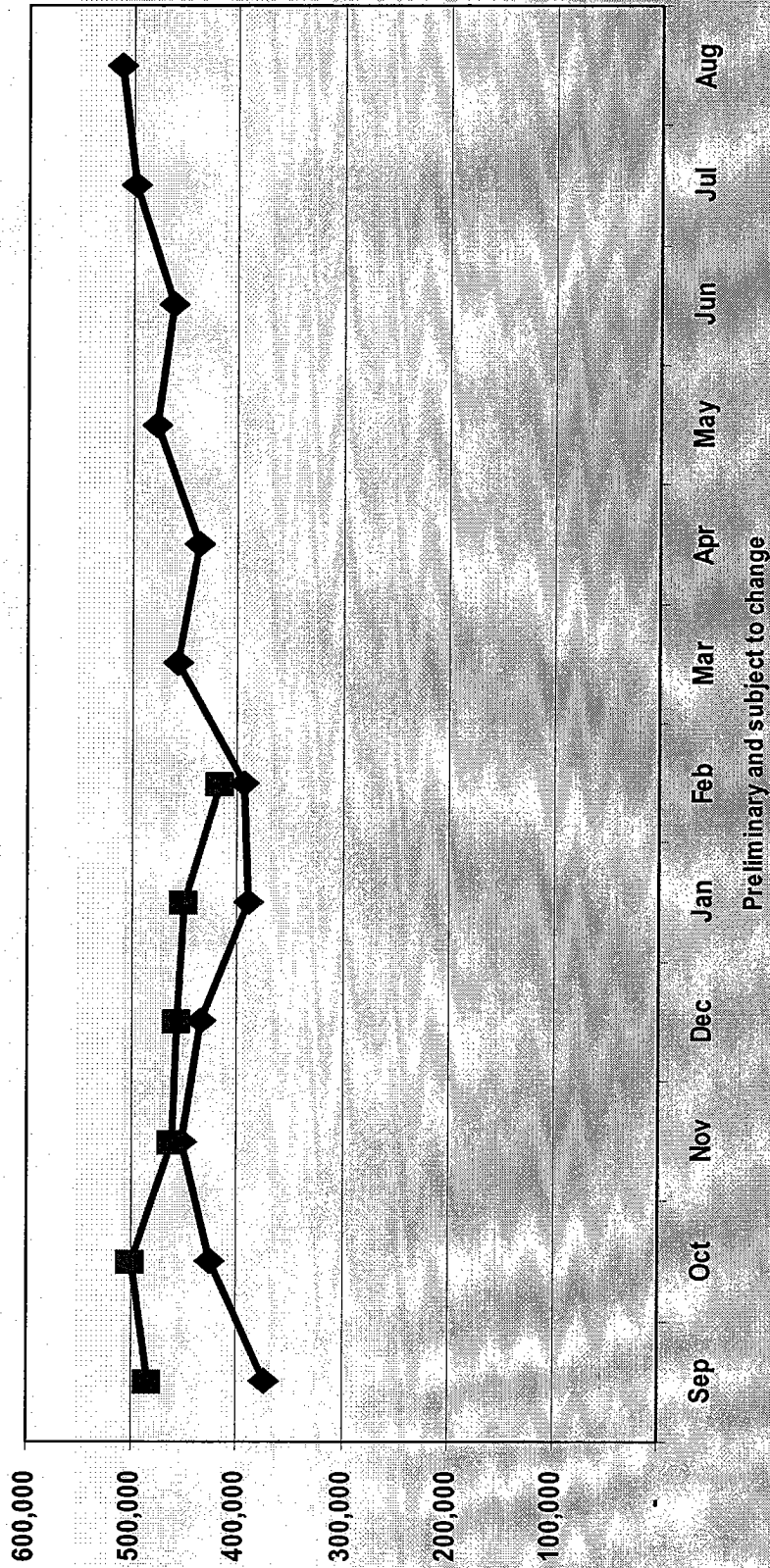
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Comparison of the Inter SC Trades Sept. 2001 through Feb. 2003

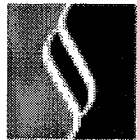


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Next Steps

- Data validation and error correction
- Maintenance of historical record

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Nature of Data: Summary of rates for 2004 GMC Rate Structure Project

Dated: June 3, 2003

Date of Release:

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2004 GMC Rate Structure Project

Comparison of Rate Proposals

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MID PROPOSED STRUCTURE Ver 1										
	Resolving Energy Imbalances REL-1	Resolving Energy Imbalances REL-2	Resolving Energy Imbalances REL-3	Managing Transmission Flows MTF-1	Managing Transmission Flows MTF-2	Managing Transmission Flows MTF-3	Administering Markets	Scheduling	Total	
% of Total	5%	10%	0%	16%	31%	0%	28%	8%	100%	
Revenue Requirement	\$ 12,788,124	\$ 24,739,120	\$ 173,820	\$ 38,666,133	\$ 74,801,131	\$ 521,460	\$ 66,870,735	\$ 19,039,848	\$	\$ 237,600,371
9/2001-8/2002 Volume	16,403,169	45,688	1,562	242,456,619	534,042	1,562	29,304,703	12,307,710		
Rate / MWh, Cust Mo	0.78	541.47	111.28	0.16	140.07	333.84	2.28	1.55		
Description	Uninstructed deviation energy	Uninstructed deviation demand (most recent 12 months)	Number of customer months	Power withdrawals	Maximum power withdrawals	Number of customer months	Trading volumes	Trading volumes		
Previously used determinants	16,506,418	25,238	984	242,456,619	534,042	984	29,327,169	12,819,845		

MID PROPOSED STRUCTURE Ver 2										
	Resolving Energy Imbalances REL-1	Resolving Energy Imbalances REL-2	Resolving Energy Imbalances REL-3	Managing Transmission Flows MTF-1	Managing Transmission Flows MTF-2	Managing Transmission Flows MTF-3	Administering Markets	Scheduling	Total	
% of Total	5%	10%	0%	48%		0%	28%	8%	100%	
Revenue Requirement	\$ 12,780,821	\$ 24,724,993	\$ 195,250	\$ 113,402,974		\$ 585,750	\$ 66,870,735	\$ 19,039,848	\$	\$ 237,600,371
9/2001-8/2002 Volume	4,868,337	3,746	1,562	242,456,619	0	1,562	29,304,703	12,307,710		
Rate / MWh or MWh Base/Tier 1	11,534,832	44,179	125.00	0.47		375.00	2.28	1.55		
Rate / MWh or MWh Tier 2	0.06	13.23	558.53							
Description	Uninstructed deviation energy	Uninstructed deviation demand (most recent 12 months)	Number of customer months	Power withdrawals		Number of customer months	Trading volumes	Trading volumes		
Previously used determinants	16,403,169	47,926	984	242,456,619		984	29,327,169	12,819,845		
Previously used determinants	16,506,418	25,238								

Exh. No. ISO- 299, Page 3 of 7

Comparison of Rate Proposals

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MID PROPOSED STRUCTURE Ver 3 Option A										
	Resolving Energy Imbalances REI-1	Resolving Energy Imbalances REI-2	Resolving Energy Imbalances REI-3	Managing Transmission Flows MTF-1	Managing Transmission Flows MTF-2	Managing Transmission Flows MTF-3	Energy Trading	AS Trading	Total	
% of Total	6%	12%	0%	18%	35%	0%	5%	23%	100%	
Revenue Requirement	\$ 14,393,400	\$ 27,844,589	\$ 195,250	\$ 43,519,838	\$ 84,190,810	\$ 585,750	\$ 12,326,784	\$ 54,543,951	\$ 237,600,372	
9/2001-8/2002 Volume Base/Tier 1	4,868,337	3,746	1,562	242,456,619	534,042	1,562	5,383,631	23,921,072		
9/2001-8/2002 Volume Tier 2	11,534,832	44,179								
Rate / MW or MWh Base/Tier 1	\$ 0.065	\$ 14.90	\$ 125.00	\$ 0.18	\$ 157.65	\$ 375.00	\$ 2.29	\$ 2.28		
Rate / MW or MWh Tier 2	\$ 1.220	\$ 629.00								
Description	Uninstructed deviation energy	Uninstructed deviation demand (most recent 12 months)	Number of customer months	Power withdrawals	Max power withdrawals (12 NCP)	Number of customer months	Trading volumes	Trading volumes		
	16,403,169									

MID PROPOSED STRUCTURE Ver 3 Option B										
	Resolving Energy Imbalances REI-1	Resolving Energy Imbalances REI-2	Resolving Energy Imbalances REI-3	Managing Transmission Flows MTF-1	Managing Transmission Flows MTF-2	Managing Transmission Flows MTF-3	Energy Trading	AS Trading	Total	
% of Total	6%	12%	0%	54%		0%	5%	23%	100%	
Revenue Requirement	\$ 14,393,400	\$ 27,844,589	\$ 195,250	\$ 127,710,648		\$ 585,750	\$ 12,326,784	\$ 54,543,951	\$ 237,600,372	
9/2001-8/2002 Volume Base/Tier 1	4,868,337	3,746	1,562	242,456,619		1,562	5,383,631	23,921,072		
9/2001-8/2002 Volume Tier 2	11,534,832	44,179								
Rate / MW or MWh Base/Tier 1	\$ 0.06	\$ 14.90	\$ 125.00	\$ 0.53		\$ 375.00	\$ 2.29	\$ 2.28		
Rate / MW or MWh Tier 2	\$ 1.22	\$ 629.00								
Description	Uninstructed deviation energy	Uninstructed deviation demand (most recent 12 months)	Number of customer months	Power withdrawals		Number of customer months	Trading volumes	Trading volumes		

Comparison of Rate Proposals

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SCE PROPOSED STRUCTURE										
	CAS	DDSS	SS	WOS	RMOS	Total				
% of Total	70.3%	0.1%	6.8%	15.6%	7.1%	100.0%				
Revenue Requirement	\$ 167,089,477	\$ 230,558	\$ 16,270,959	\$ 37,136,426	\$ 16,872,951	\$ 237,600,371				
9/2001-8/2002 Volume	239,156,619	3,300,000	237,779,865	29,304,703	16,403,169					
Rate / MWh or MWh	0.699	0.070	0.068	1.267	1.029					
Description	MWh of Control Area	MWhs of gen dynamically dispatched to other Control Areas over non-ISO T behind-the-meter)	MWh of scheduled energy + self-provided AS (final schedules)	MWh of pur/sales of energy + AS	MWh of uninstructed imbalance energy					
Load (Exclusive of retail										
Previously used determinants	239,156,619	3,300,000	244,244,847	29,327,169	16,506,418					
DWR Variation on ISO Proposed Structure										
	Core Reliability Services	Energy & Transmission Services	Energy & Transmission Services Deviation	Scheduling	Congestion Management	Market Operations	Customer Service			Total
% of Total	39%	13%	3%	8%	4%	12%	20%			100%
Revenue Requirement	\$ 93,544,836	\$ 30,670,132	\$ 7,667,533	\$ 19,039,848	\$ 10,017,448	\$ 28,775,078	\$ 47,885,496			\$ 237,600,371
9/2001-8/2002 Volume	440,946	242,456,619.45	16,403,168.73	12,307,710	87,927,387	45,707,872	1,562			
Rate / MWh, MWh, Cust Mo	212.15	0.13	0.47	1.55	0.11	0.63	500.00			
Rate / MWh Cust Serv Adder		0.09	0.34		0.05	0.32				
Total Rate / MWh, MWh, Cust Mo	212.15	0.22	0.81	1.55	0.16	0.95	500.00			
Description	Gross coincident peak demand MW--12 CP Basis	Net Control Area Load plus exports in MWh	Absolute value of net uninstructed deviations by settlement interval in MWh	Final HA schedules submitted, no charge for changes to DA schedules	Net Scheduled Interzonal load (flows)/MWh	Purchases and sales of Ancillary Services, instructed energy and absolute value of net uninstructed deviations by settlement interval MWh	Minimum of \$500/mo			
Previously used determinants	440,946	242,456,619.45	16,506,418.01	12,819,845	87,927,387	45,833,587	1,653,395.978			

Comparison of Rate Proposals

Note: The following is pasted from the GMC Analysis Tool-MID & MID file REI Data.xls

Rate summaries 6-02-03.xls

Comparison of Rate Proposals

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Proposed Rate Structure	Resolving Energy Imbalances	Managing Transmission Flows	Energy Trading	AS Trading	Total
% of Total	6%	18%	5%	23%	100%
Revenue Requirement 9/01-8/02 Vol: Tier 1	\$ 14,393,400	\$ 43,519,838	\$ 12,326,784	\$ 54,543,951	\$ 237,600,372
9/01-8/02 Vol: Tier 2	4,873,932	242,456,619	5,406,097	23,921,072	
Description	11,577,685		Trading volumes		
Uninstructed deviation energy		Power withdrawals			
Rate / MWh: Tier 1	\$ 0.0648	\$ 0.1795	\$ 2.2802	\$ 2.2802	
Rate / MWh: Tier 2	\$ 1.2759				

Proposed Rate Structure	Resolving Energy Imbalances	Managing Transmission Flows	Energy Trading	AS Trading	Total
% of Total	12%	35%	2%	53%	100%
Revenue Requirement 9/01-8/02 Vol: Tier 1	\$ 27,844,589	\$ 84,190,810	\$ 2,193,339	\$ 97,806,679	\$ 212,035,417
9/01-8/02 Vol: Tier 2	3,806	534,042	97,806,679	100,000,000	
Description	46,319	Maximum power withdrawals			
Uninstructed deviation demand (most recent 12 months)					
Rate / MWh: Tier 1	\$ 14.66	\$ 157.65			
Rate / MWh: Tier 2	\$ 599.94				

Proposed Rate Structure	Resolving Energy Imbalances	Managing Transmission Flows	Energy Trading	AS Trading	Total
% of Total	0%	0%	0%	100%	100%
Revenue Requirement 9/2001-8/2002 Volume	\$ 195,250	\$ 585,750	\$ 1,562	\$ 375.00	\$ 1,136,612
Description	1,562	Number of customer months			
Rate / Customer Month	\$ 125.00	\$ 375.00			



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Preliminary Analysis of Bill Impacts

2004 GMC Rate Structure Project

June 4, 2003

Ben Arikawa

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What is New?

- Initial data verification
 - SC IDs
 - Duplicate data

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Bill Impacts

- SCE Proposal
- MID Proposal
 - Option A
 - Option B
- ISO Proposal (12 NCP)
- DWR Proposal (12 CP)

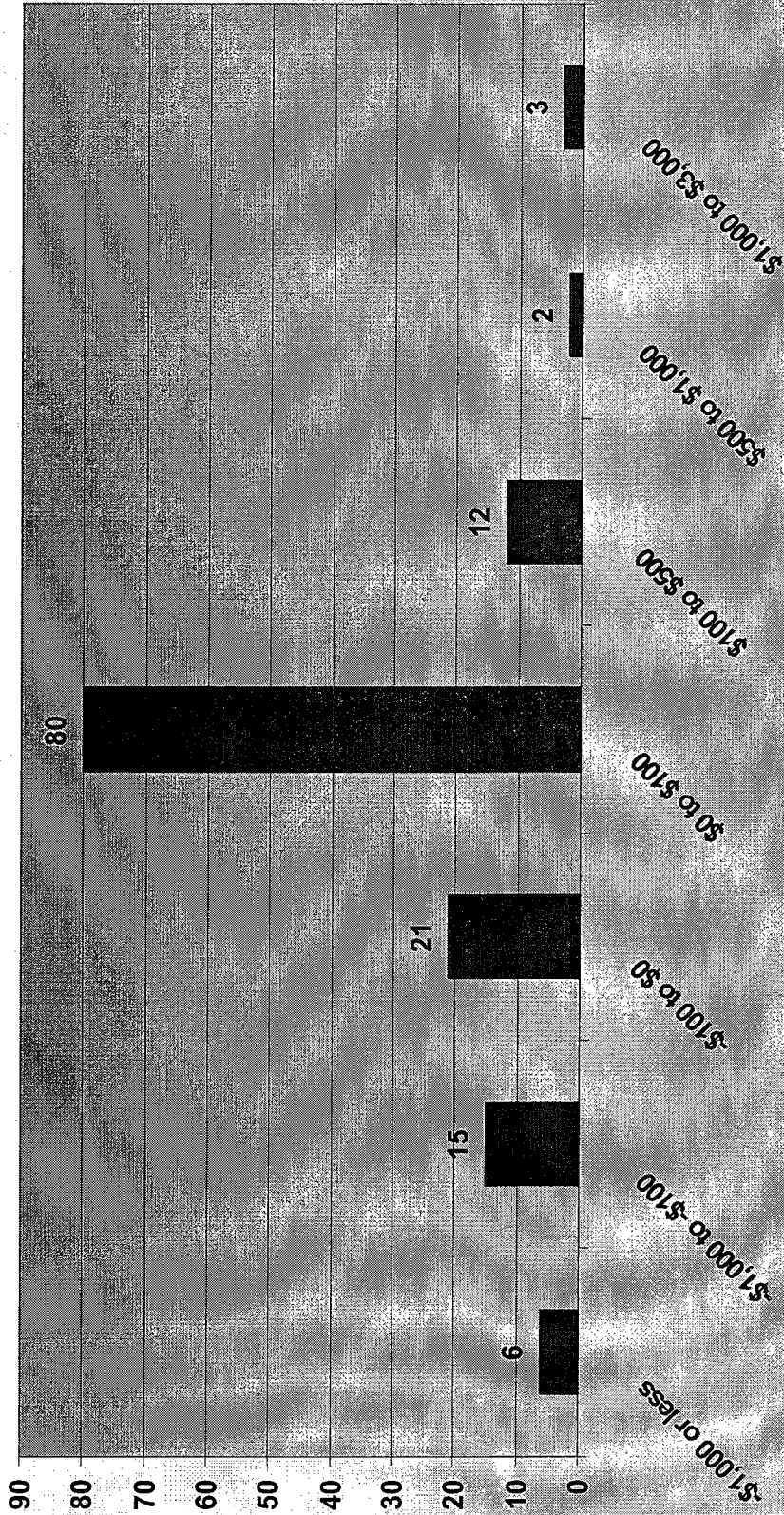
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Distribution of Bill Impacts: SCE Proposal (in thousands of dollars)



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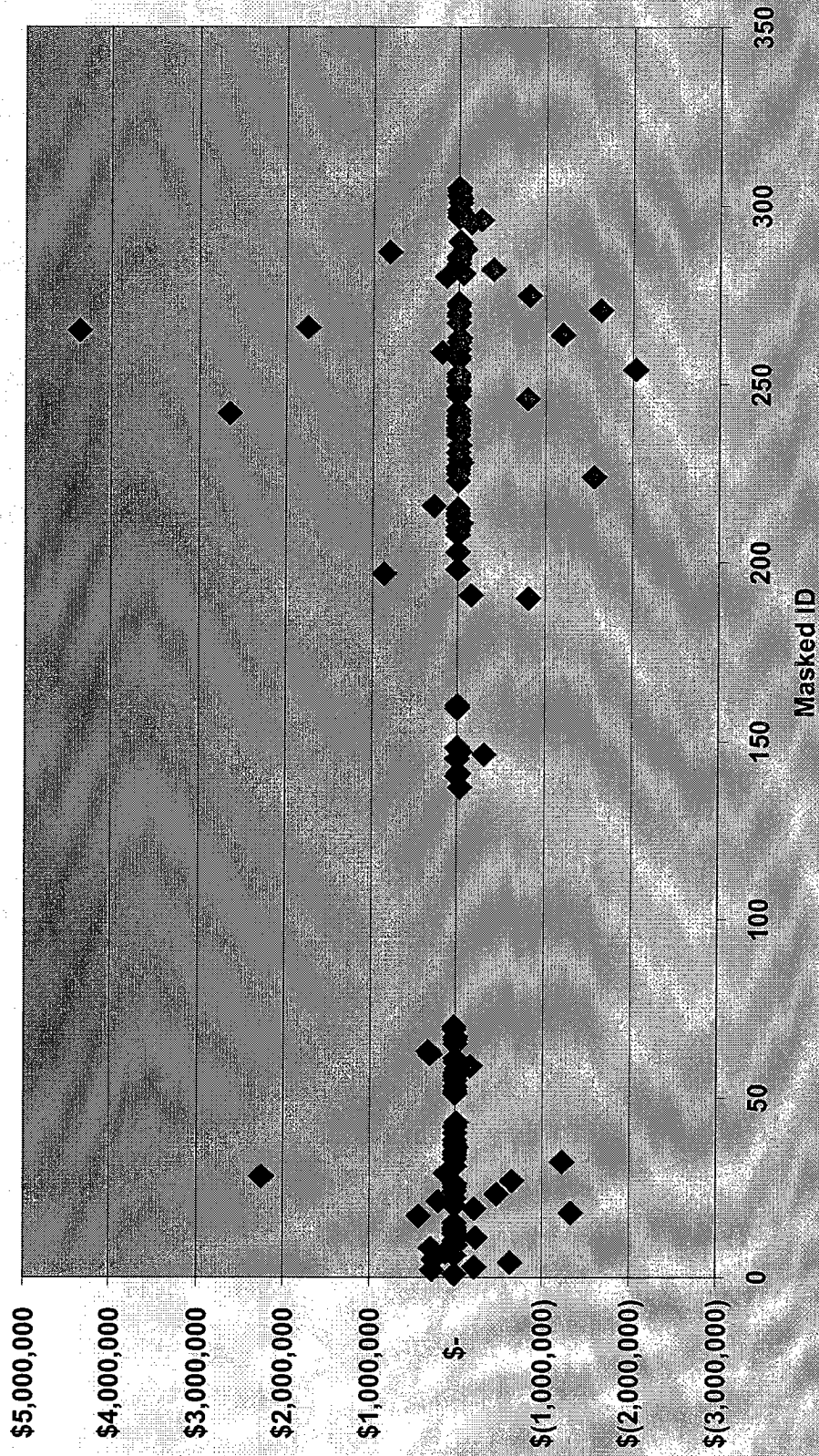
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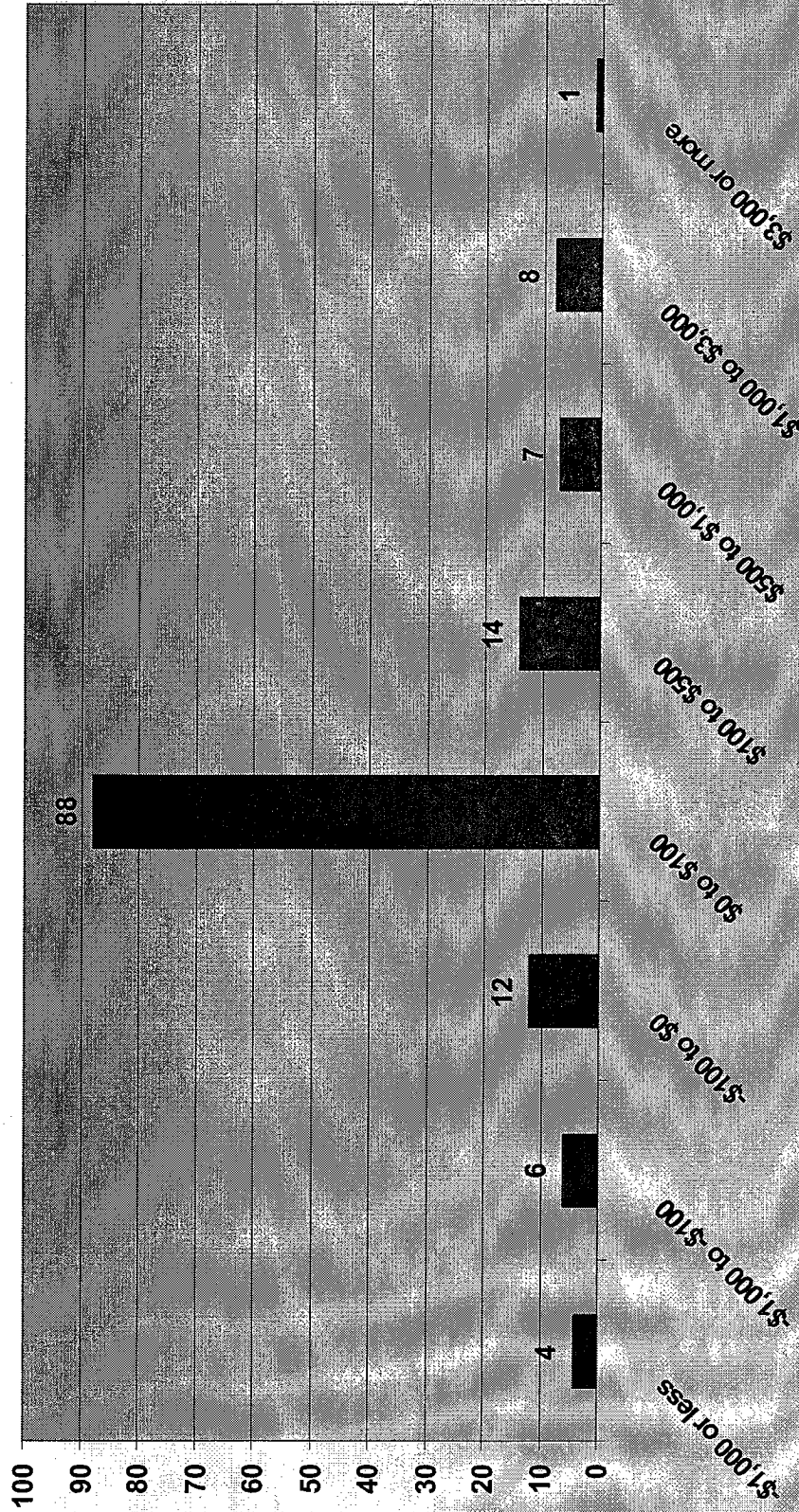
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Distribution of Bill Impacts: MID 3 Proposal Option A (in thousands of dollars)



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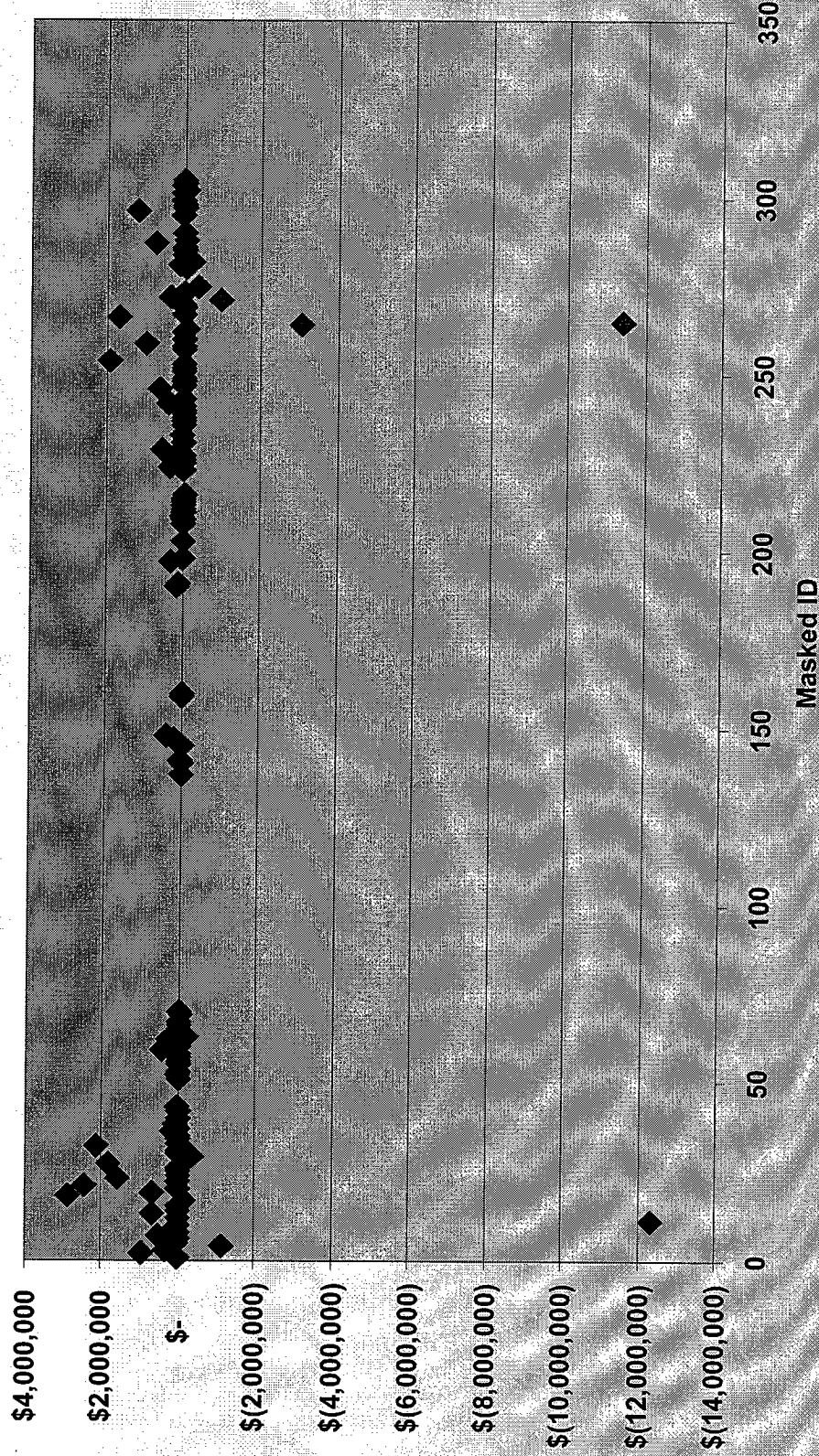
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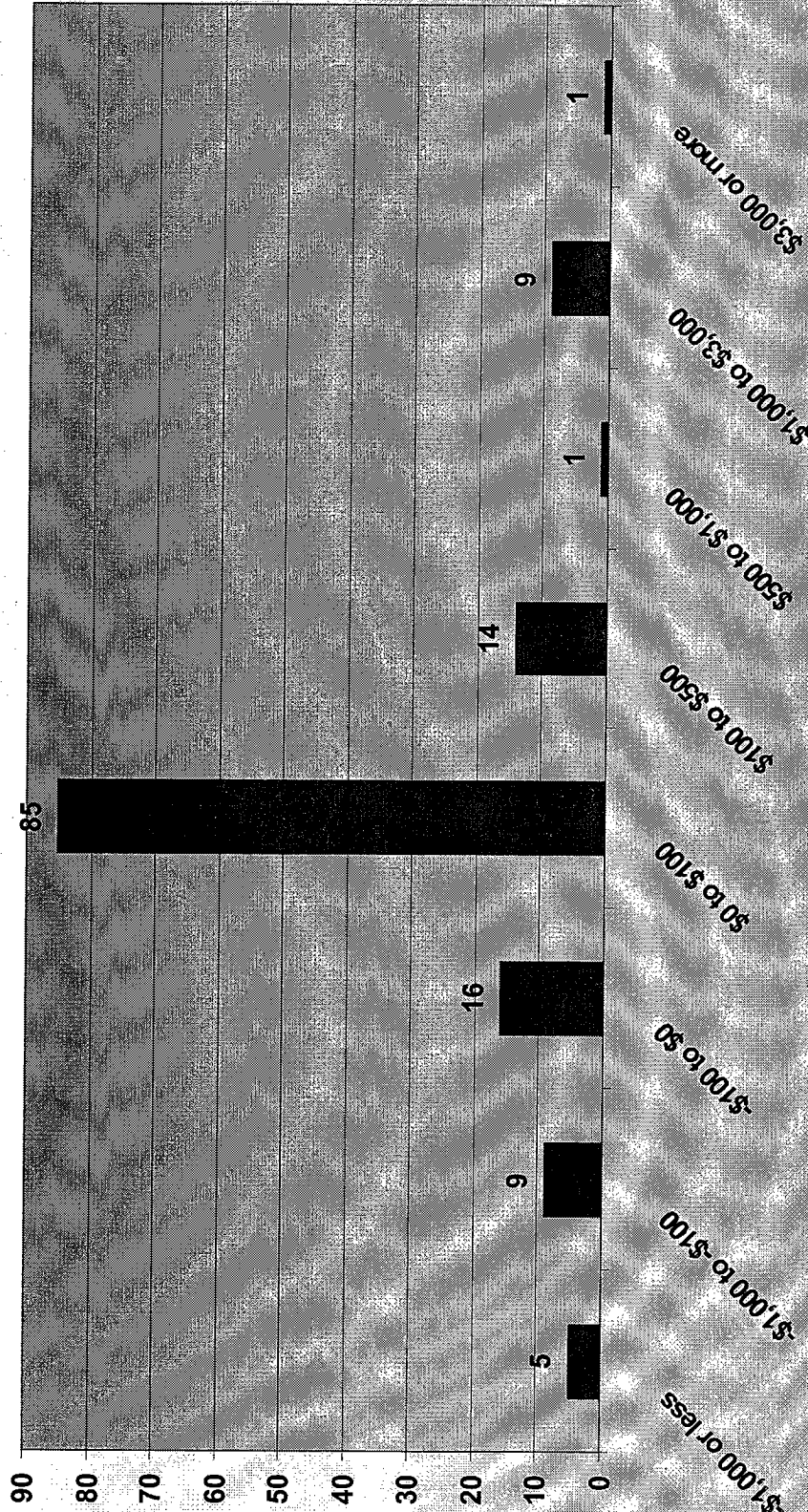
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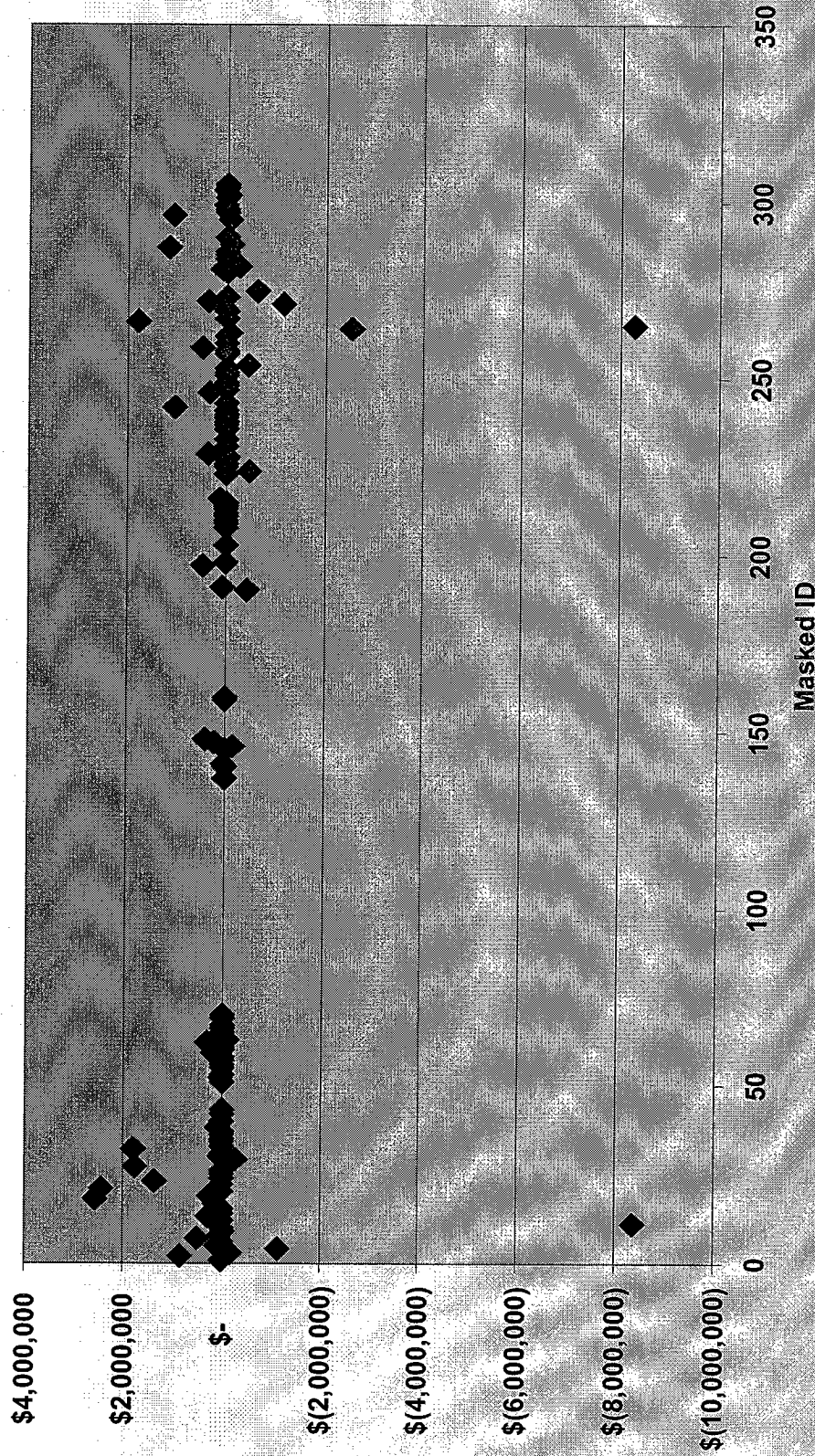
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Distribution of Bill Impacts MID 3 Proposal Option B



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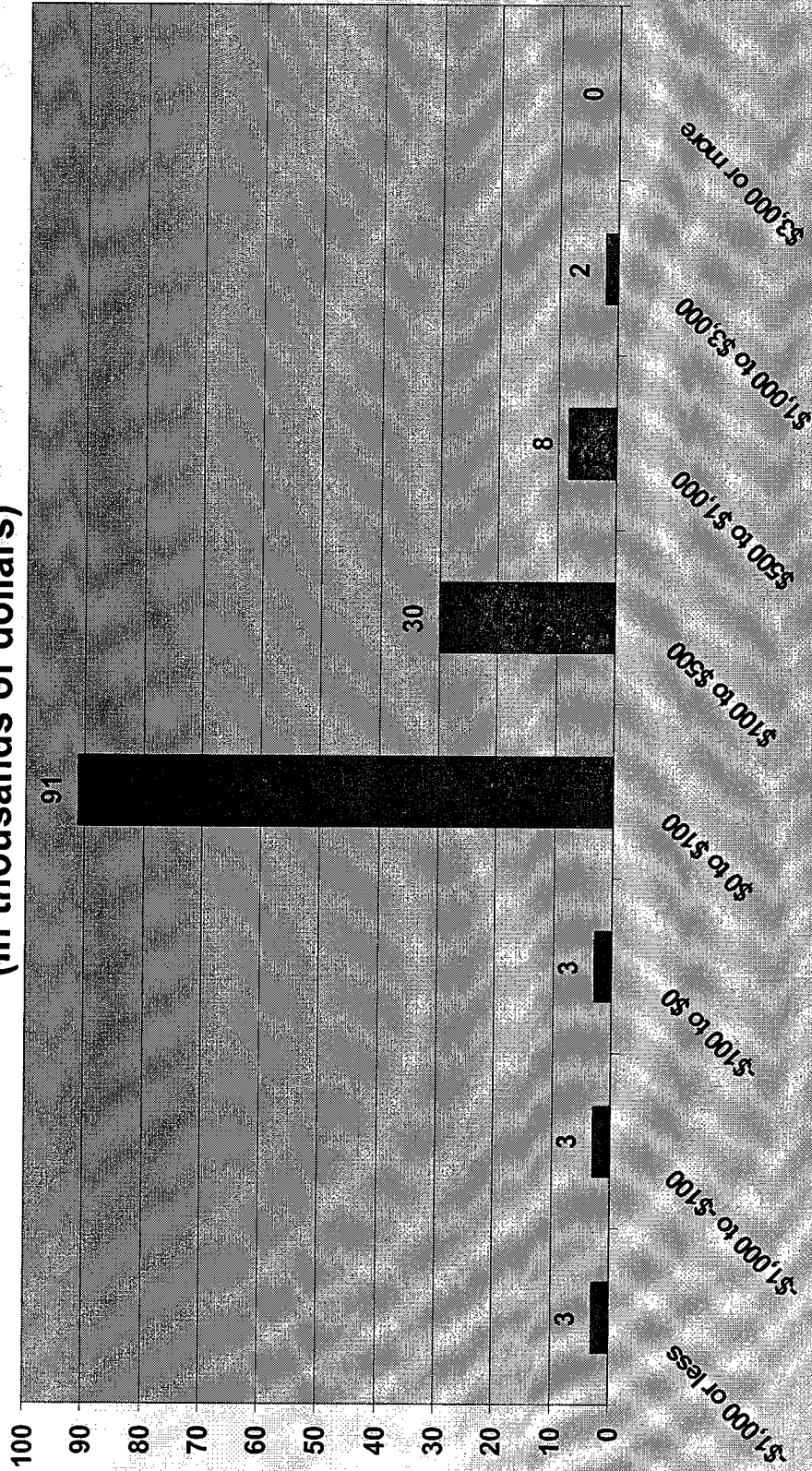
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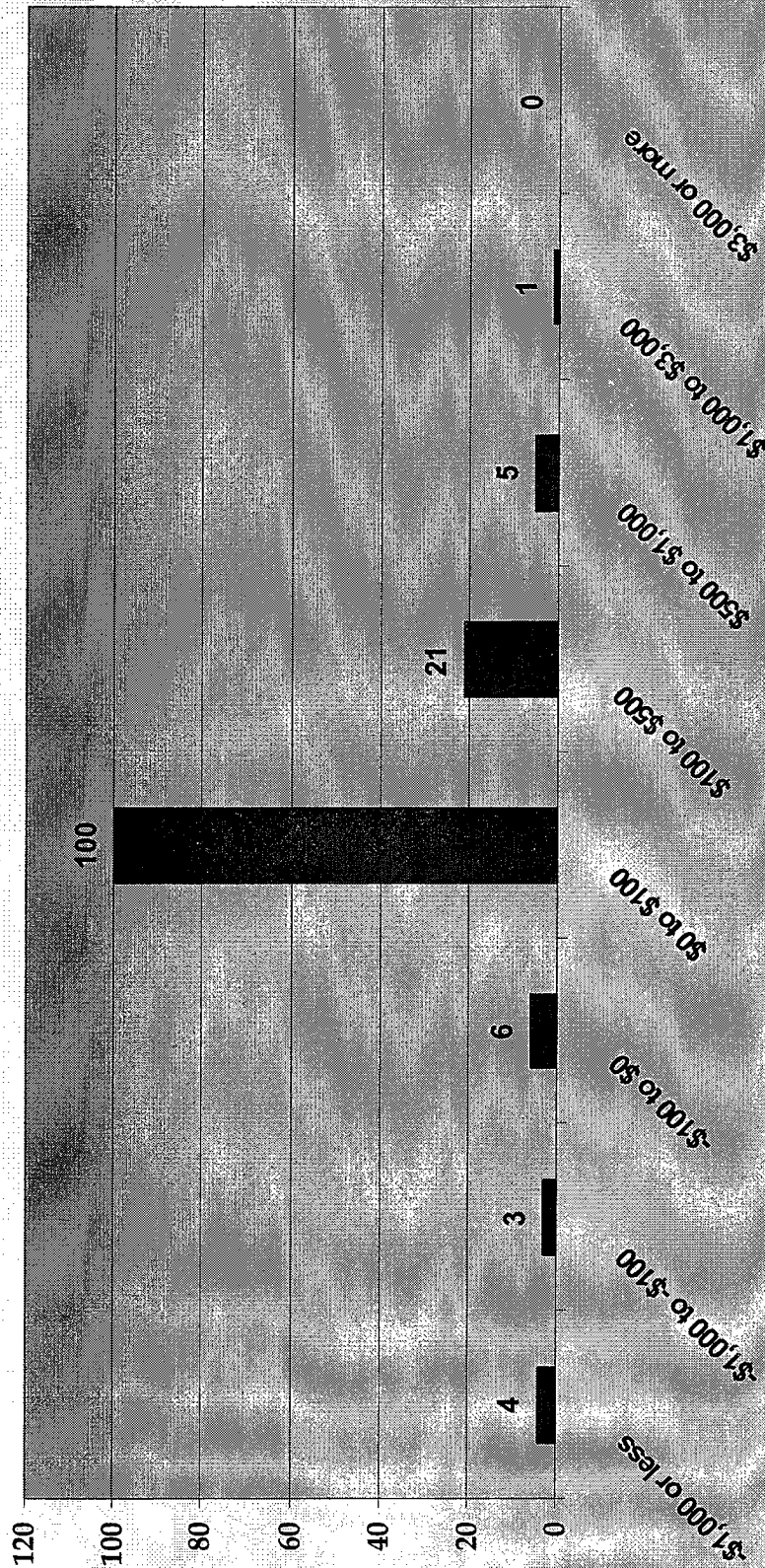
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Distribution of Bill Impacts: DWR Proposal (12 CP) (in thousands of dollars)



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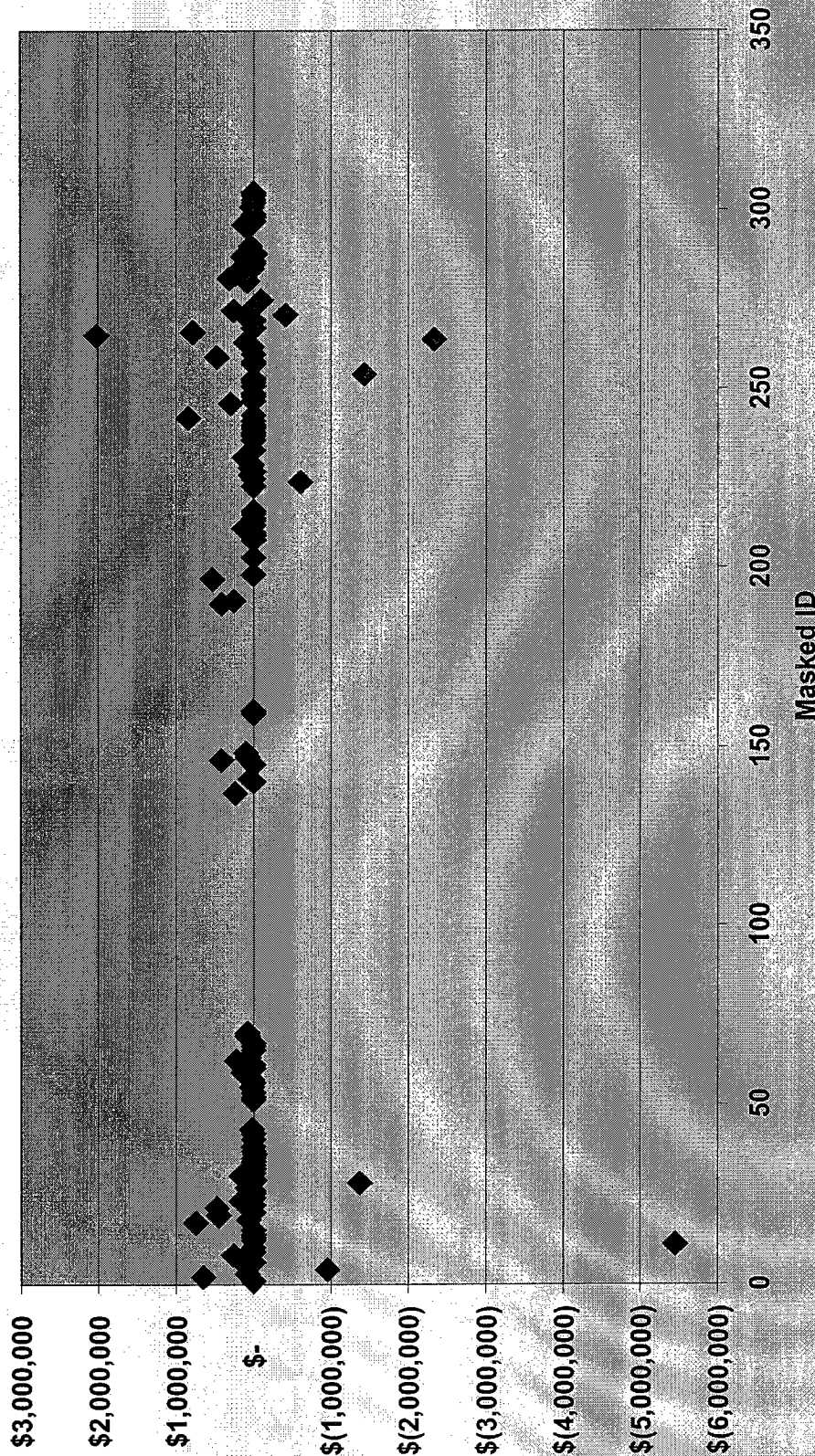
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Distribution of Bill Impacts DWR Rate Proposal (12 CP)



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Next Steps

- Review of data
- Review of calculations
- Pursue additional mitigation, if necessary

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Agenda
2004 GMC Rate Structure Project
California ISO, Folsom
Wednesday, June 4, 2003
9:00 p.m. to 3:00 p.m.

Public Session

Conference Call-in #1-888-788-6681 Passcode: 98563

1. Introductions/roll call
2. Discussion of June 6 Board Presentation
3. Initial review of Appendix B issues
4. Initial review of billing determinant stability
5. SCE proposal update
6. MID proposal update
 - a. Development of tiered rates
 - b. New portions of proposal
7. ISO proposal update
 - a. Behind the meter load NCP
 - b. Discussion of scheduling activities
 - c. Discussion of functional association of Settlements, Metering and Client Relations costs
 - d. Discussion of cost assignment method (if time permits)

Confidential Session

1. Bill impact analysis
2. Discussion of cost assignment method (if time permits)

See notes and participant list below:

Notes to June 4, 2003 meeting of 2004 GMC Rate Structure Project

The meeting began with a discussion of the stability of billing determinants. The ISO had compiled some, but not all, of the billing determinant data for the proposals through February 2003. The ISO presentation included updates on the following billing determinants:

NCP

Net Control Area Load plus exports

Net Hour-Ahead scheduled interzonal flows

Net uninstructed deviations

Sum of the maximum net uninstructed deviations

Inter-SC trades.

The ISO showed monthly comparisons (September 2001 to August 2002 overlaying September 2002 to February 2003) that would capture seasonal variations. With the exception of net uninstructed deviations, all billing determinants appeared to be at or above the previous year's value. Net uninstructed deviations were more volatile, both last year and this year.

There were a number of clarifying questions. Were the Southern Cities load excluded in the data? Answer – no, the Southern Cities load has always been included as they have been in the Control Area. Was SMUD's load taken out? Answer – Yes.

The slide on net uninstructed deviations caused a number of questions to be raised concerning net uninstructed deviations. The ISO was asked to investigate the cause of the large reduction in deviations that began in January 2002.

There was some concern that the removal of the balanced schedule requirement would affect inter-SC trades negatively. SDG&E commented that the \$1.55 per hourly schedule submitted charge seemed high. The ISO clarified that the charge only applied to the schedule, not the MWhs in the schedule and that all schedules would be charged, not just inter-SC trades.

The next discussion was on the ISO's briefing to the Board on June 6, 2003. Several parties requested to see the presentation prior to its posting. In this presentation, the ISO would outline the stakeholder process and the three proposals. This was only a briefing and would not contain any action items on the part of the Board.

Phil Leiber continued with a discussion of Appendix B (of the 2002 GMC Settlement) issues. The ISO presented a working draft of a listing of documents showing the ISO response to the various issues in Appendix B. This led into a discussion of the interpretation of the Appendix B issues.

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There was a discussion of the impact of MD02 on expenditures. The ISO stated that, currently, the only major unforeseen MD02 expenditure was for a new Settlements system valued between \$5 and \$10 million.

David Cohen asked when the ISO thought it would be able to issue new debt. Phil Leiber responded that the ISO was unlikely to be able to issue debt in the foreseeable future. Even if all major debtors to the ISO were creditworthy and all current transactions paid, S&P would not upgrade the ISO's credit rating unless all outstanding market payments from previous years were fully paid.

There were several more questions concerning the impact of MD02. IEP asked if there would be a fee on owners of units subject to Residual Unit Commitment (RUC). The ISO responded that there would be no separate charge for RUC, that it would be part of the Integrated Forward Market.

SDG&E asked about the cost of MD02. Approximately \$10 million had been spent in 2002 and \$15 million budgeted in 2003. The ongoing O&M costs were not known.

David Cohen asked if MSSs would be subject to congestion management charges. The ISO responded that the MSSs were currently subject to congestion management charges as they no longer had ETCs.

Finally, several parties brought up the issue of alternative tracking of costs through the use of timecards or better tracking of workload. This was also in the context of Appendix B issues.

SCE was asked to present an update on its proposal. SCE was reviewing its proposal in light of the May 2 order in ER0-313-000. SCE was considering a demand charge for its Control Area Services charge.

CDWR asked if SCE had a cost justification for its DDES charge. SCE responded that a cost allocation for this service would not lead to an equitable rate. One needed to look at the benefits provided to those exports, which would lead to a smaller number. SCE went on to explain that of the 9 CAS activities shown in the ISO's 2001 GMC filing, Mohave exports only benefited from 2.

There was a discussion of the uniqueness of the situation of Mohave exports. SCE pointed out that the DDES only applied to generation in the ISO control area exported over transmission lines not owned by PTOs to load outside the control area. The ISO pointed out that there were no other entities similarly situated and the ISO would oppose the use of dynamic dispatch for any other entities.

IEP stated that if the DDES were implemented, it would set a dangerous precedent.

The ISO next presented an update to its proposal. The ISO recounted its functionalization. The ISO introduced revised billing determinants for the Core Reliability Services (CRS) and for Energy and Transmission Services (ETS). The CRS billing determinant would now be monthly NCP by SC ID. The ISO would not include an adder for behind the meter load. The ISO had determined that the Tariff required SCs to submit gross meter data, but that this was currently under litigation at the FERC. The ALJ had issued an Initial Decision adverse to the ISO. Pending a final order from the full Commission, the ISO had offered exemptions to the metering requirement QFs. Until a final order is issued, the ISO would assume that SCs were abiding by the Tariff.

The billing determinant for ETS had changed from net control area load to "Controlled Grid Load plus exports." Numerically, this should be slightly smaller than net control area load plus exports, but the ISO had not yet compiled the data. Controlled Grid Load plus exports was similar to the concept used for determining the Wheeling Access charge. There were some questions, particularly from SCE, concerning what was included or excluded in Controlled Grid Load plus exports.

The scheduling function and billing determinant were discussed next. MID had some questions regarding the homogeneity of schedules within the billing determinant. In particular, MID questioned if the cost of processing AS trades and inter-SC trades was the same as those for other schedules.

David Cohen requested that the ISO hold a meeting so that participants could ask questions of Barkovich and Yap on the methodology used for functional association of charge types to billing determinants. Cohen also thought that this meeting could be used for discussion of the cost assignment methodology used by the ISO. Both CDWR and CAC joined in this request.

CDWR raised the question of the justification for using coincident peak instead of non-coincident peak.

David Cohen asked if the ISO could rename its Reliability Services function since the name conflicted with the name being used by other utilities. After some discussion, the name "Grid Reliability Services" was chosen.

At this point, MID presented updates to its proposal. MID had developed an Options A and B to its proposal that included (excluded) a demand charge on the Managing Transmission Flows function.

In MID's Resolving Energy Imbalances charge, there was some discussion on how the tiers for energy and demand were developed. MID stated that small deviations were more likely to be noise or to be offset by other small deviations so that the ISO's costs of resolving them was likely to be small. This set off a long discussion of the ISO's activities in resolving small imbalances relative to large imbalances. There were a

number of comments that asked if, within an interval, the ISO could distinguish between large and small imbalances by SC ID.

MID stated that it would be willing to consider a different basis for its tiers.

The next topic of discussion was scheduling of meetings and conference calls. A meeting was set for June 30th at the ISO. This meeting would include discussions with Barkovich and Yap concerning functional association of charge types, cost assignment methodology and the justification for NCP. A conference call was scheduled for June 16th to allow parties an opportunity to discuss updates to their proposals prior to the June 26th ISO Board meeting.

The final minutes of the meeting were taken up with a discussion of bill impacts. The ISO committed to providing updated bill impacts in sufficient detail so that participants could see the causes of changes in bills.

Participants to June 4, 2003 meeting

Last Name	First	Company	Telephone	E-mail Address
Aoki	Rod	CAC	(415) 421-4143	rsa@a-klaw.com
Arikawa	Ben	ISO	(916) 608-5958	barikawa@caiso.com
Auclair	Phil	Mirant	(925) 287-3144	philippe.Auclair@mirant.com
Barkovich	Barbara	Barkovich and Yap		
Bonaly	David	CDWR	(916) 574-0663	bonaly@water.ca.gov
Brommer	Mike	TID	(209) 883-8320	mtbrommer@tid.org
Brown	Kim	ISO		
Cogdill	Jan	ISO		
Cohen	David	Navigant Consulting	(503) 708-7852	dcohen@navigantconsulting.com
Firooz	Sharon	SDG&E	(858) 650-6158	sfirooz@semprautilities.com
Hansen	Bert	SCE	(626) 302-3649	berton.hansen@sce.com
Kaplan	Katie	IEP	(916) 448-9499	kaplan@iepa.com
Key	Jennifer	SCE		
Kirsch	Laurence	Christensen Associates	(415) 663-8608	lkirsch@lrca.com
Kissel	Peter	CDWR		
Lam	Tony	EOB	(916) 322-8632	tlam@eob.ca.gov
Leiber	Phil	ISO	(916) 351-2168	pleiber@caiso.com
LeVine	Debi	ISO	(916) 351-2144	dlevine@caiso.com
Lyon	Deane	ISO	(916) 351-2428	dlyon@caiso.com
Markey	Jerry	ISO		
McGuffin	Mike	ISO	(916) 608-5753	mmcguffin@caiso.com
Morrison	Stephen	ISO	(916) 608-7143	smorrison@caiso.com
Neal	Sean	MID		
Olsson	Ray	EOB	(916) 322-8628	rolsson@eob.ca.gov
Paradise	Theodore	ISO		
Peterson	Mike	ISO	(916) 608-5896	mpeterson@caiso.com
Pritchard	Jan	MID	(209) 526-7490	ianp@mid.org
Regan	William	ISO	(916) 351-4450	wregan@caiso.com
Ross	James	CAC	(626) 530-9544	jimross@r-c-s-inc.com
Ryan	Mike	WAPA	(916) 353-4434	mryan@wapa.gov
Sandino	David	CDWR	(916) 653-5129	dsandino@water.ca.gov
Shea	Karen	CPUC	(415) 703-5404	kms@cpuc.ca.gov
Slaton	Jeffery	EOB	(916) 322-8601	islaton@eob.ca.gov
Smith	Kevin	Braun and Associates		smith@braunlegal.com
Springer	John	ISO		jspringer@caiso.com
Takehara	James	NCPA	(916) 781-4293	james.takehara@ncpa.com
Terry	Lee	CDWR	(916) 574-0664	lterry@water.ca.gov
Timson	David	ISO		dtimson@caiso.com

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Withrow	David	ISO	(916) 608-7134	dwithrow@caiso.com
Yakin	Dale	PG&E	(415) 973-1752	dgy4@pge.com
Yap	Catherine	Barkovich and Yap		

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Standing Information Request 06-06-03.txt

From: lkirsch@svn.net
Sent: Friday, June 06, 2003 9:24 AM
To: Arikawa, Ben
Cc: Pritchard, Jan; Neal, Sean
Subject: Standing Information Request

Please see attachment.

Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.
e-mail: LKIRSCH@LRCA.COM
voice: (415) 663-8608
fax: (415) 663-8818

Please visit our website at WWW.LRCA.COM

The logo for Christensen Associates, featuring the company name in a bold, sans-serif font. The word "CHRISTENSEN" is on the top line and "ASSOCIATES" is on the bottom line, both in all caps. The text is white and set against a dark, textured rectangular background.

Laurits R. Christensen Associates, Inc.
4610 University Avenue, Suite 700
Madison, Wisconsin 53705-2164

Voice 608.231.2266 Fax 608.231.2108

TO: Ben Arikawa
FROM: Laurence Kirsch & Ross Hemphill
DATE: June 6, 2003
SUBJECT: Standing Information Request

We would like to make a standing request for you to send us any and all information the ISO is using or may use in the future when converting its current GMC proposal from the use of historical data to the use of prospective data. This information is necessary for MID to fully evaluate the expected impacts of MD02 when the rate design moves from historical data to prospective data.

Thank you.



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2004 GMC Rate Structure Project Status Report

**June 6, 2003
Board of Governors**

**Presented by:
Phil Leiber, Treasurer & Director of Financial Planning**

Disclaimer: The details contained herein are subject to change as part of an ongoing review process, therefore the ISO does not represent this information is either complete or final. Any references to other entities GMC structure proposals are not warranted as accurate, are intended as informational summaries only and do not represent an endorsement by the ISO of such proposals.

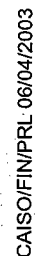


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Agenda

- Current GMC Structure
- Why Change?
- 2004 GMC Rate Structure Project, a Stakeholder Process
- Status of three proposals for 2004 GMC
- Next steps

Exh. No. ISO- 304, Page 3 of 31



Current GMC Structure

Function	Description
Control Area Services	All necessary activities attributable to reliable operation of a Control Area.
Congestion	Management and operation of inter-zonal congestion markets.
Ancillary Services and Real Time Energy Operations	Markets for supplemental energy and Ancillary Service bids, Open Access Same-Time Information System (OASIS), market monitoring & performance.

Current GMC Structure

Costs & Billing Determinants

Service Category	% of ISO Costs	Billing Determinants
Control Area Services	58%	Gross Control Area Load & Exports in MWh (5/2/2003 FERC order modifies for behind the meter load for QFs, munis)
Congestion	12%	Net interzonal scheduled load in MWh
Ancillary Services and Real Time Energy Operations	30%	Purchases and sales of ancillary services and real time energy, including uninstructed deviations (at a resource-level) in MWh



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Purpose of 2004 GMC Rate Structure Project

- Initial Decision in ER01-313-000, *et.al.*
(affirmed by Commission Order)
 - Requires ISO to reevaluate its rate structure
 - Requires evaluation of different proposals
- Settlement in ER02-250-000, *et. al*
- Analyze different rate structures
- Develop basis for new ISO rate structure effective January 1, 2004



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Project History

- Commencement: August 2002
- August 2002 – June 2003
 - Approximately 20 meetings and conference calls
- Board presentations June – July 2003



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2004 GMC Rate Structure Project Materials

- 2004 GMC Rate Structure Project web page on CAISO website
 - Documents
 - Public Discussion Board
 - Confidential Discussion Board
 - Accessible from
<http://www.caiso.com/docs/2002/08/02/2002080216283419989.html>



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Participants

- Participants
 - CAC/EPUC, CDWR/SWP, CMUA, CPUC, EMS, EOB, FERC staff, IEP, MID, Mirant, NCPA, Navigant (representing municipal utilities), PG&E, SCE, Sempra, TID, WAPA



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Status

- **Three Full Proposals Developed:**
 - ISO
 - Modesto Irrigation District
 - Southern California Edison
- **Modifications to ISO proposal requested:**
 - CPUC additions for FTR MWhs and ETCs (now withdrawn)
 - CDWR would replace NCP with CP.



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ISO Proposal Service Categories

Function	Description
Core Reliability Services	All necessary activities attributable to reliable operation of a Control Area including the capability of handling a system that is as geographically dispersed as the present system, but without features that are scalable.
Energy & Transmission Services	Scalable portion of Control Area operations.
Forward Scheduling	Provides SCs with ability to forward schedule energy and Ancillary Services.
Congestion	Management and operation of inter-zonal congestion markets.
Market Usage	Markets for supplemental energy and Ancillary Service bids, Open Access Same-Time Information System (OASIS), market monitoring & performance.
Settlements, Metering, Client Relations	Interface to scheduling coordinators through metering, settlements, and client relations.



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ISO Proposal

Costs & Billing Determinants

Service Category	% of ISO Costs	Billing Determinants
Core Reliability Services	39%	• Non-coincident peak demand in MW
Energy & Transmission Services	16%	• Controlled Grid Load & Exports" in a PTO service territory • Net uninstructed deviations
Forward Scheduling	8%	• Schedules submitted to SI (load, generation, import, export, inter-SC trade, awarded AS (including self-provided)
Congestion	4%	• Net scheduled interzonal flows in MWh
Market Usage	12%	• Purchases and sales of AS, instructed energy and net uninstructed deviations in MWh
Customer Service	20%	• \$500 per SC ID per month, remainder of costs reassigned to other categories



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SCE Proposal

Service Categories

Function	Description
Control Area Services (CAS)	Service to all control area load ensuring safe and reliable operation of the transmission grid and dispatch of bulk power supplies.
Dynamic Dispatch Export Services (DDES)	Service that the ISO provides to generation within the ISO control area that is dynamically dispatched to other control areas over transmission owned by other entities. This service is taken in lieu of "CAS" to qualifying dynamically dispatched export energy.
Scheduling Service (SS)	Inclusion of energy or ancillary services schedules in the ISO's day-ahead or hour-ahead aggregate schedule, ensuring that the market participant may produce and transmit energy or withdraw energy from the grid if the schedule is accepted, avoiding other charges related to market operation.
Market Operation Services (MOS)	Participation in any day-ahead, hour-ahead ISO market, or supplemental energy market, both for energy and for ancillary services.
Real Time Operation Services (RTOS)	Service that the ISO provides to market participants that have uninstructed imbalances. This service allows the participant to balance its aggregate supply and load.

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SCE Proposal

Costs & Billing Determinants

Service Category	% of ISO Costs	Billing Determinants
Control Area Services (CAS)	70.3%	• Net control area load plus exports MWh
Dynamic Dispatch Export Services (DDES)	0.1%	• Exports from Mohave to NP and SRP in MWh
Scheduling Service (SS)	6.8%	• Scheduled load (energy + self provided A/S final schedules) in MWh
Market Operation Services (MOS)	15.6%	• Purchases and sales of AS and instructed energy in MWh
Real Time Operation Services (RTOS)	7.1%	• Net uninstructed deviations in MWh



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MID Proposal Service Categories

Function	Description
Resolving Energy Imbalances (REI)	Ensuring aggregate resources (generation plus imports) equal aggregate demands (load plus losses plus exports) at every instant in time.
Managing Transmission Flows (MTF)	Ensuring transmission flows do not exceed transmission capabilities.
Administering Markets (AM)	Customers can voluntarily trade energy, ancillary services, or financial transmission rights in advance of real time.



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MID Proposal

Costs & Billing Determinants

Service Category	% of ISO Costs	Billing Determinants
Resolving Energy Imbalances (REI)	17.9	• Uninstructed deviation energy in MWh with two tiered rates • Uninstructed deviation demand in MW with two tiered rates • Number of SCs
Managing Transmission Flows (MTF)	54.0	• Power withdrawals in MWh • (Optional: Proposal B includes, Proposal A does not) Maximum power withdrawals in MW • Number of SCs
Administering Markets (AM)	28.1	• A/S & Energy trading volumes in MWh

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Similarities

Attribute	ISO	SCE	MID
Provide for full recovery of ISO costs	Yes	Yes	Yes
Further unbundling	Yes	Yes	Yes
Markets charge	Yes	Yes	Yes
Billing Determinants			
Use of uninstructed deviations as BD for reliability based charge	Yes	Yes	Yes



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Differences

Attribute	ISO	SCE	MID
Number of functions	6 categories	5 categories	3 categories
Billing Determinants			
Use of non-volumetric measures	Yes	No	Yes
Assess charges for control area load other than for use of ISO controlled grid	Yes	Yes (muni)/ No (QF)	No
Demand Charge?	Yes	No	Yes
Use of multi-part billing determinants?	Yes	No	Yes
Use of a fixed per SC charge?	Yes	No	Yes
Use of tiered charges	No	No	Yes

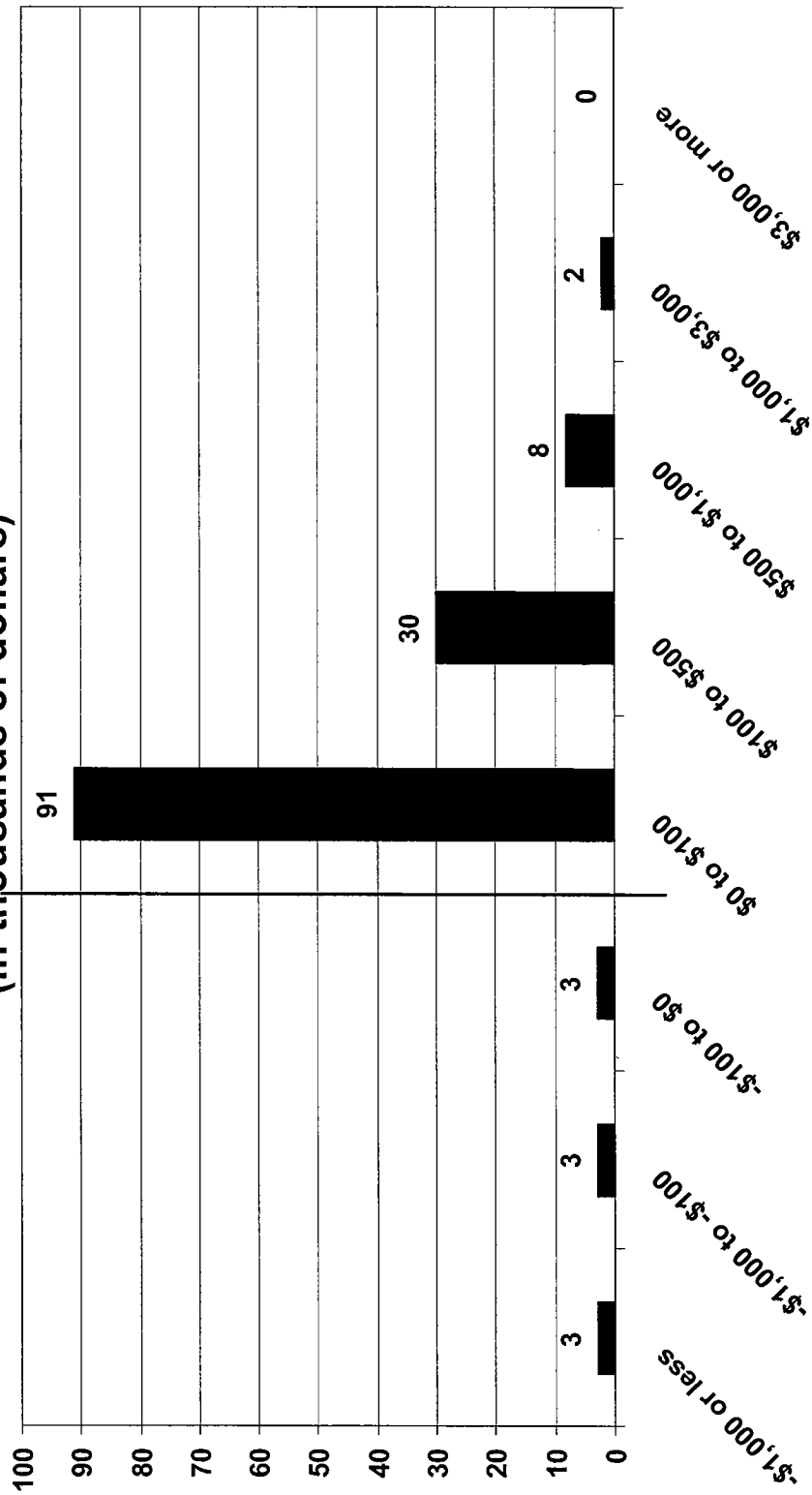


Customer Impacts

- All proposals result in SCs paying more or less than under the current arrangement
- Extent and distribution of shifts differ



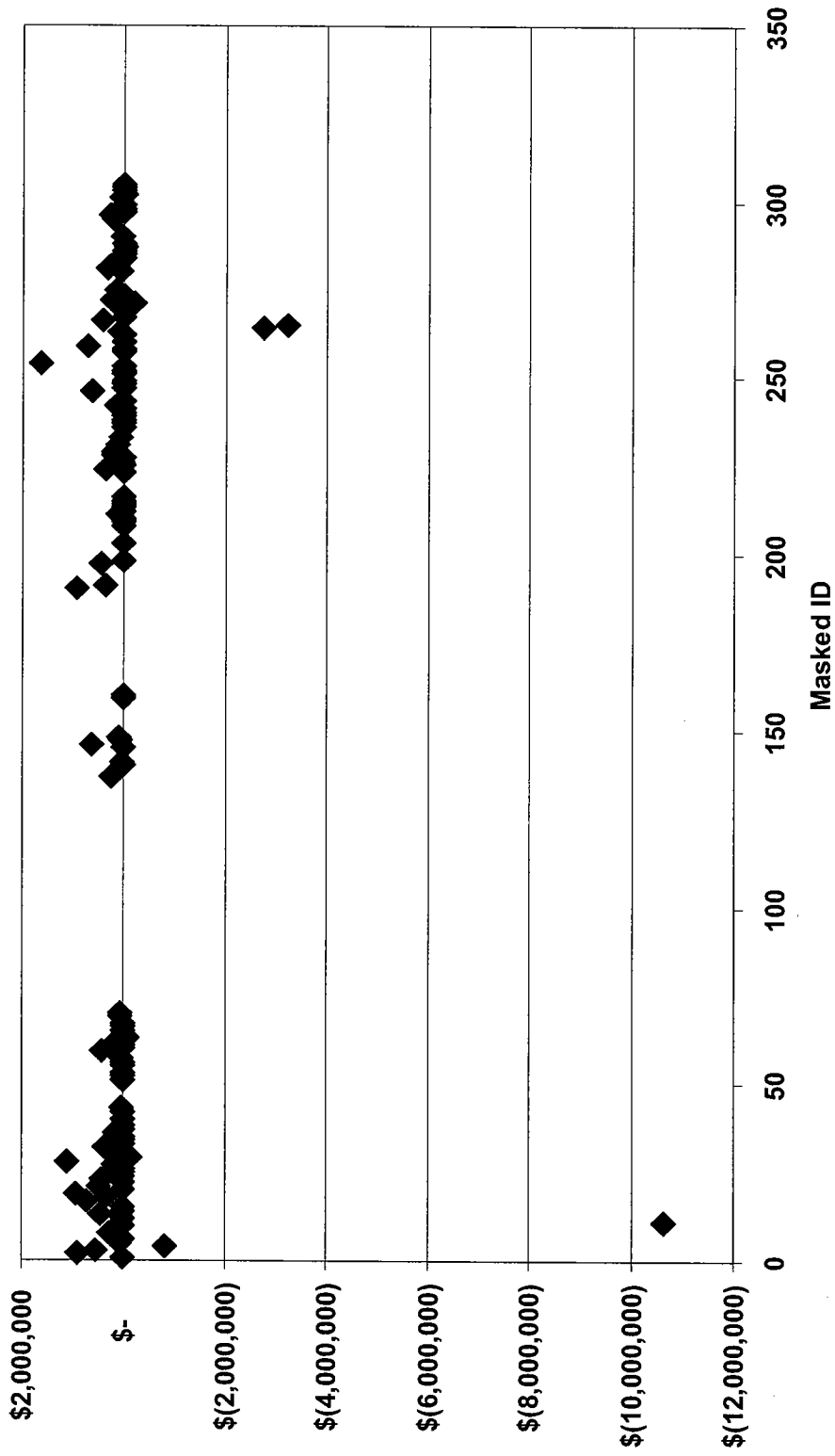
Distribution of Bill Impacts: ISO Proposal
(in thousands of dollars)



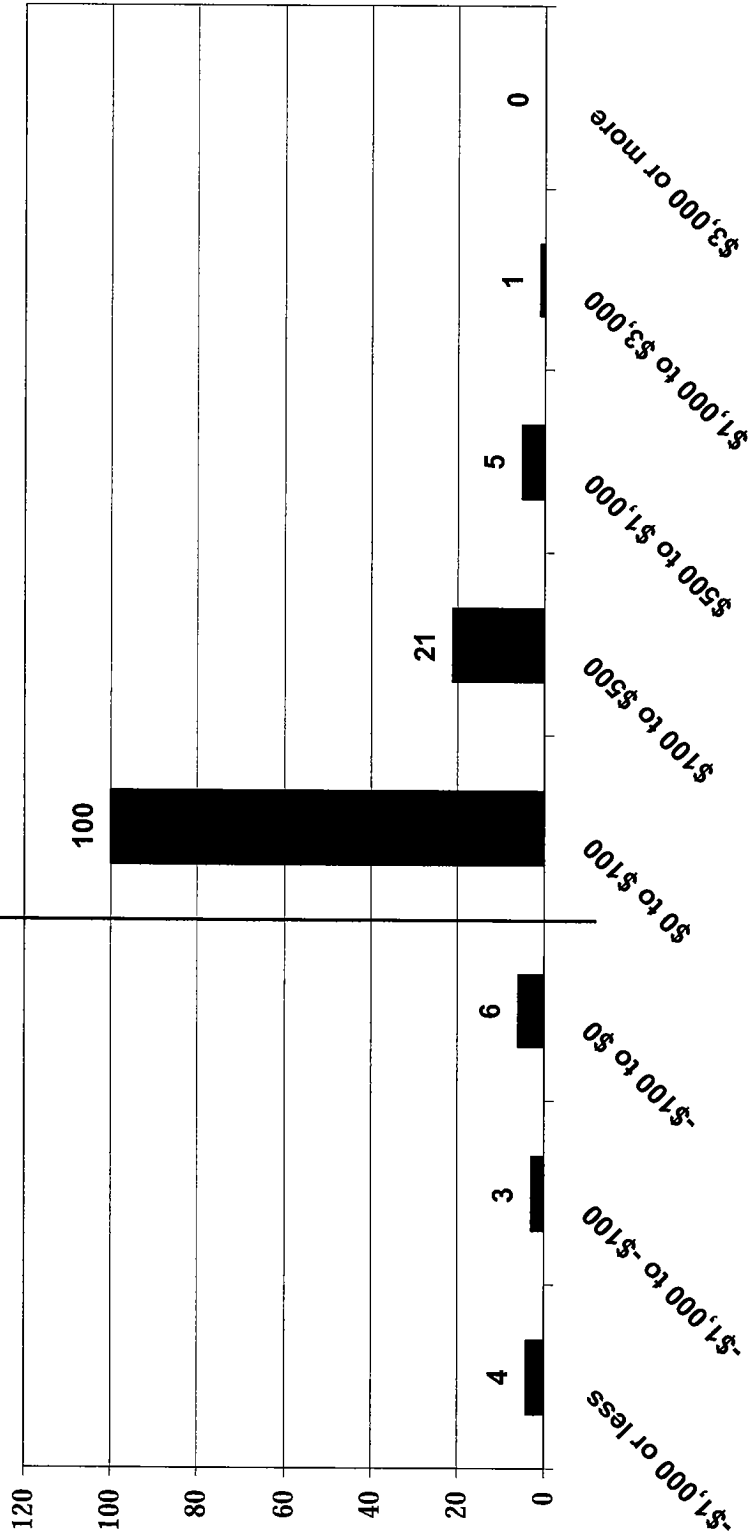


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Distribution of Bill Impacts ISO Rate Proposal

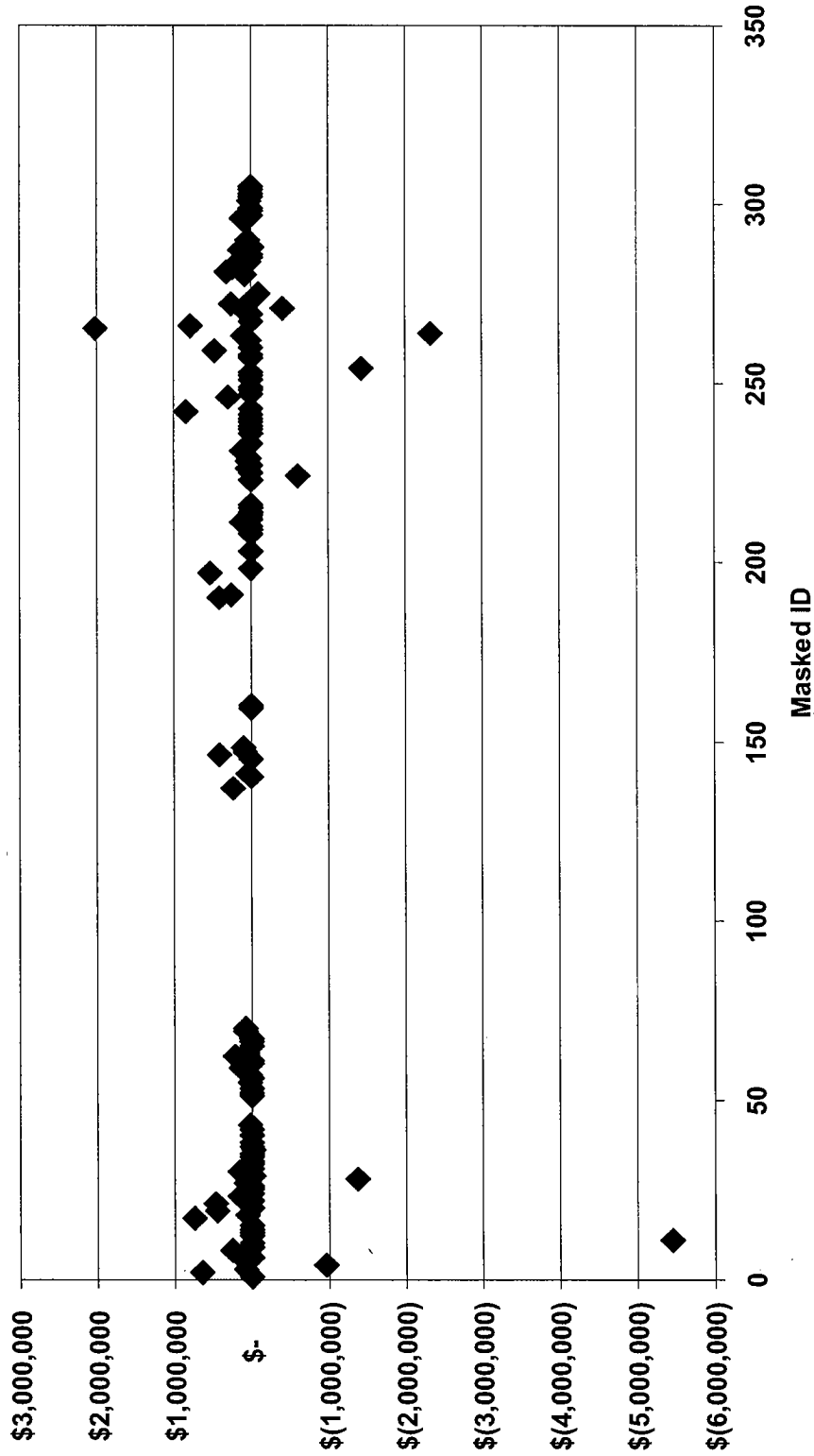


Distribution of Bill Impacts: DWR Proposal (12 CP) (in thousands of dollars)





Distribution of Bill Impacts DWR Rate Proposal (12 CP)

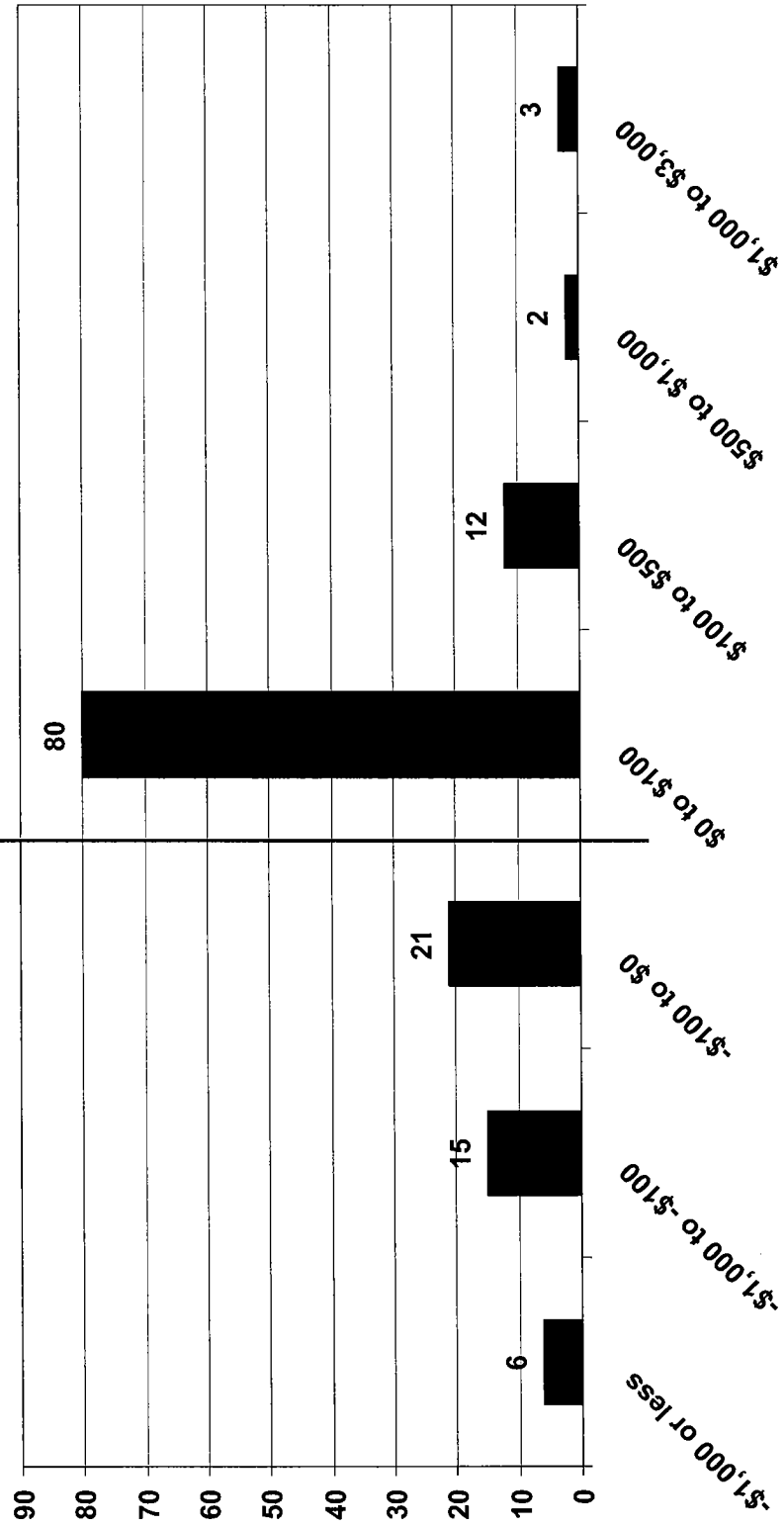




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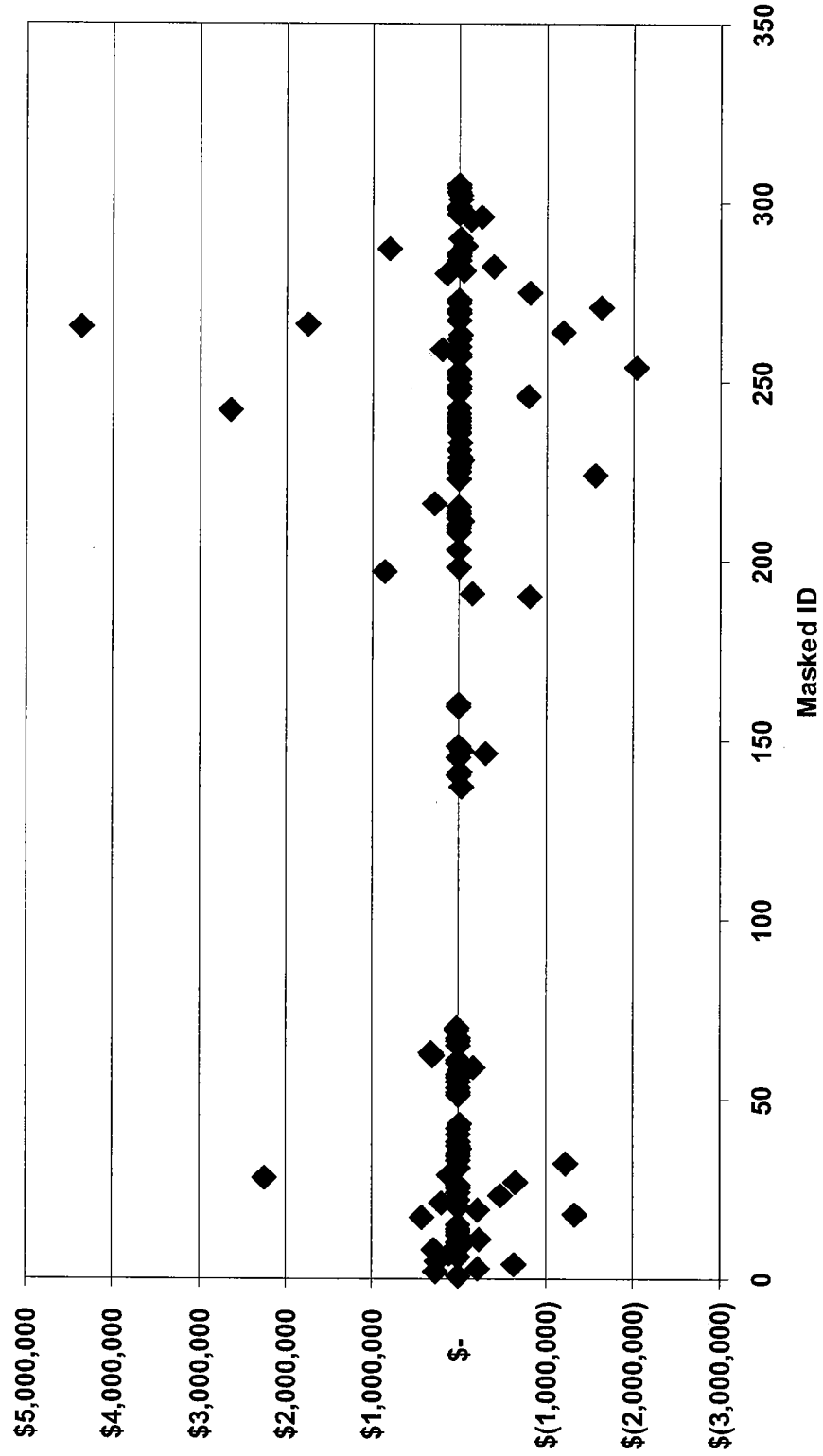
Distribution of Bill Impacts: SCE Proposal
(in thousands of dollars)





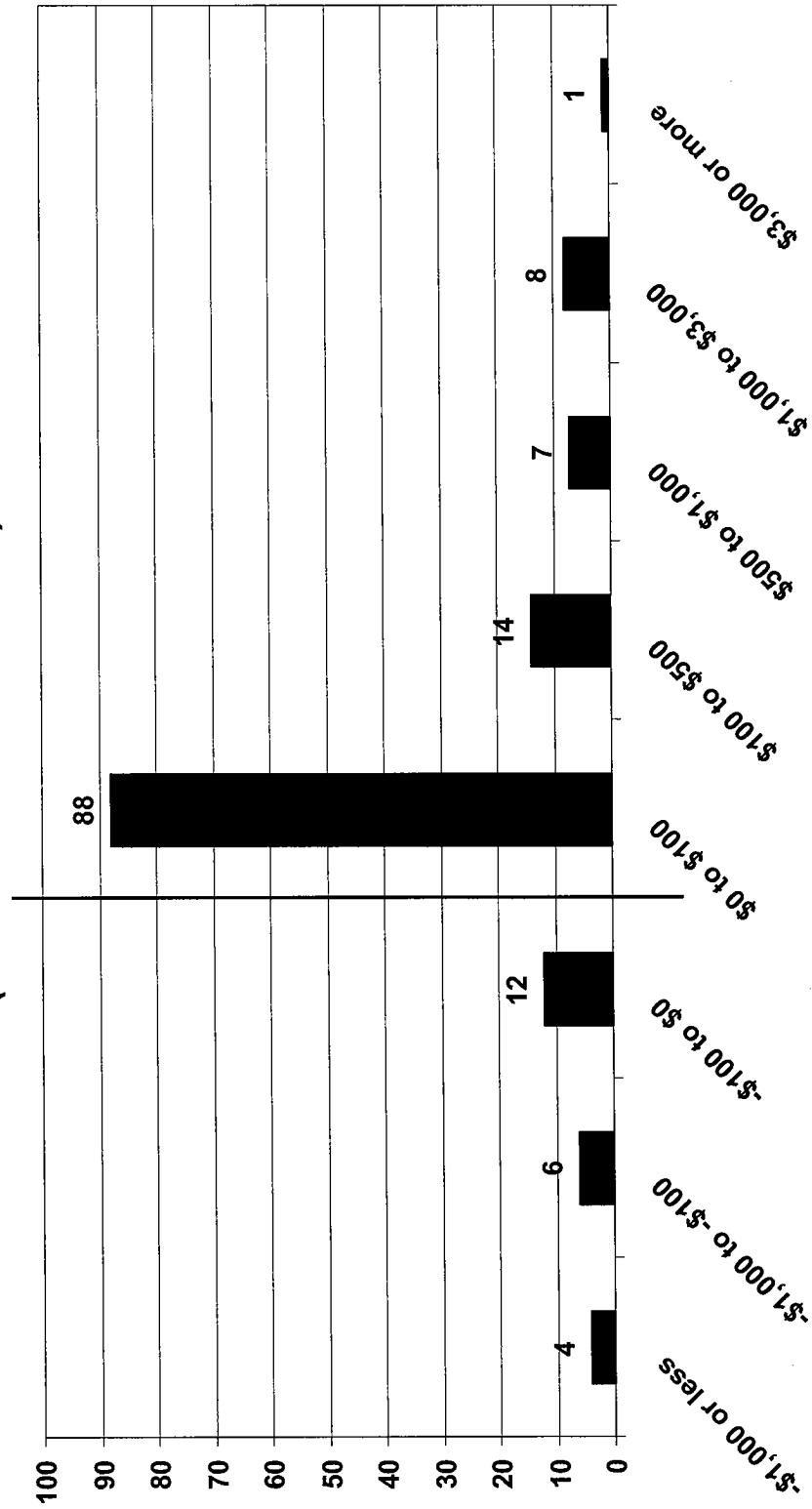
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Distribution of Bill Impacts SCE Rate Proposal



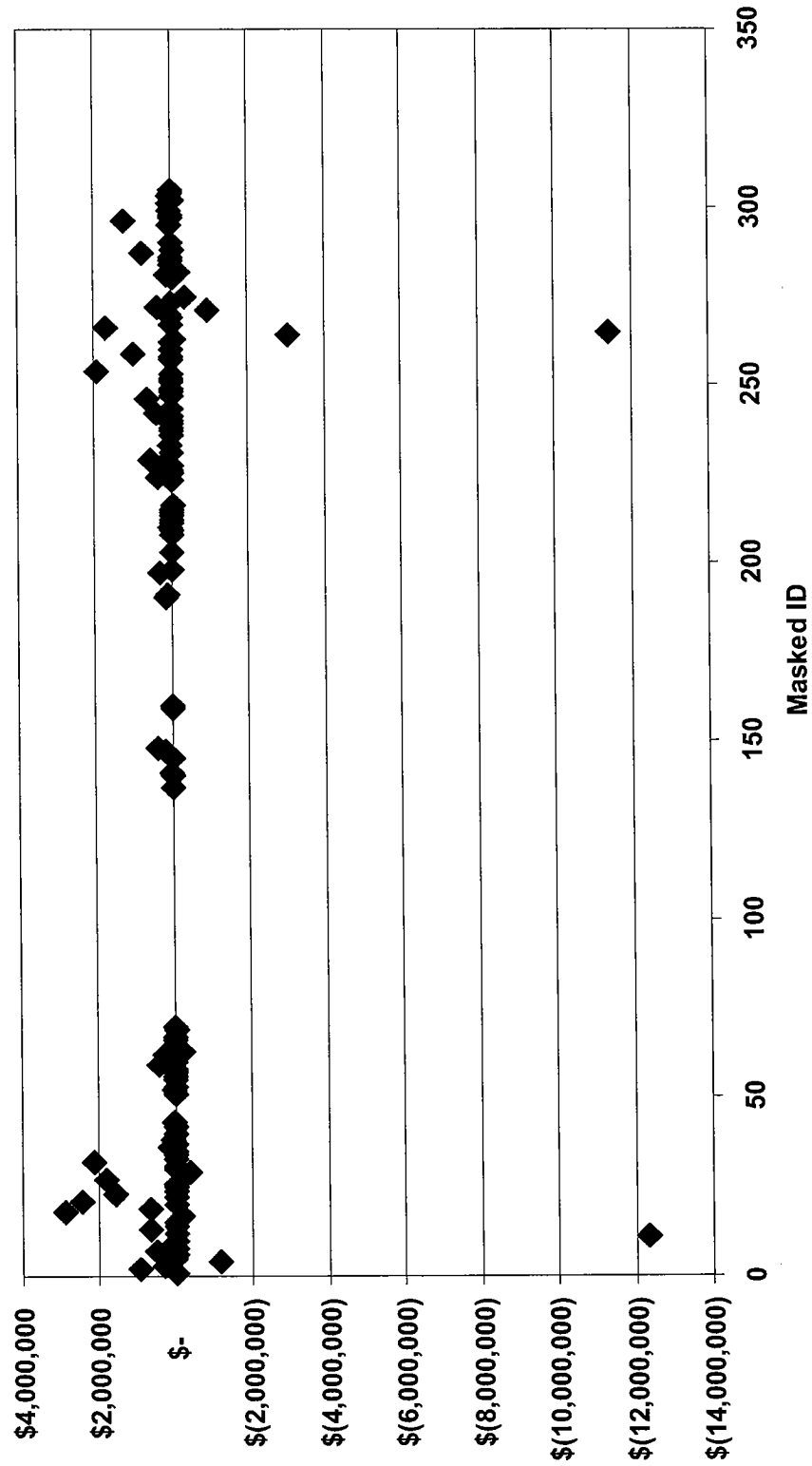


Distribution of Bill Impacts: MID 3 Proposal Option A (in thousands of dollars)



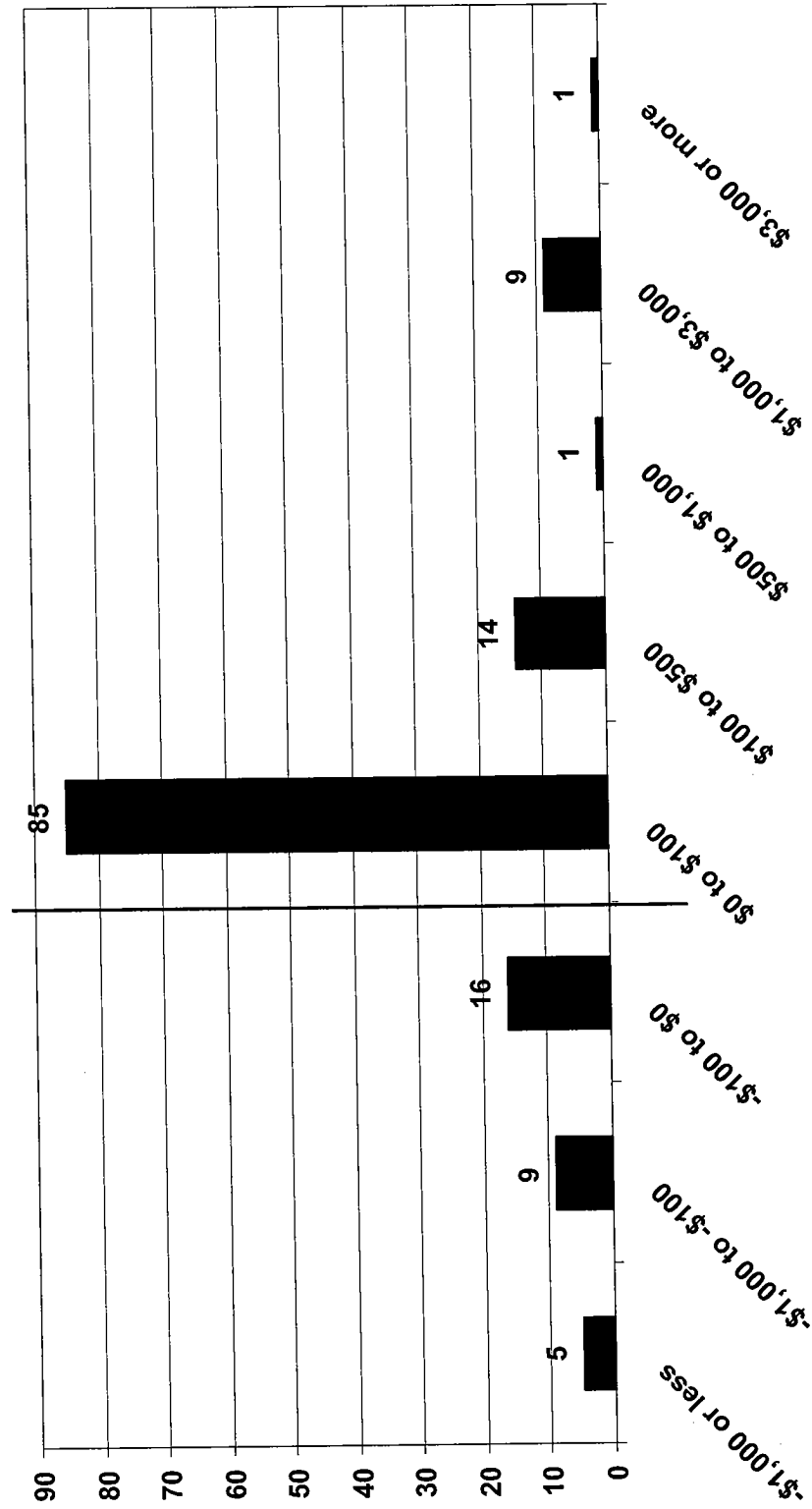


Distribution of Bill Impacts MID 3 Proposal Option A



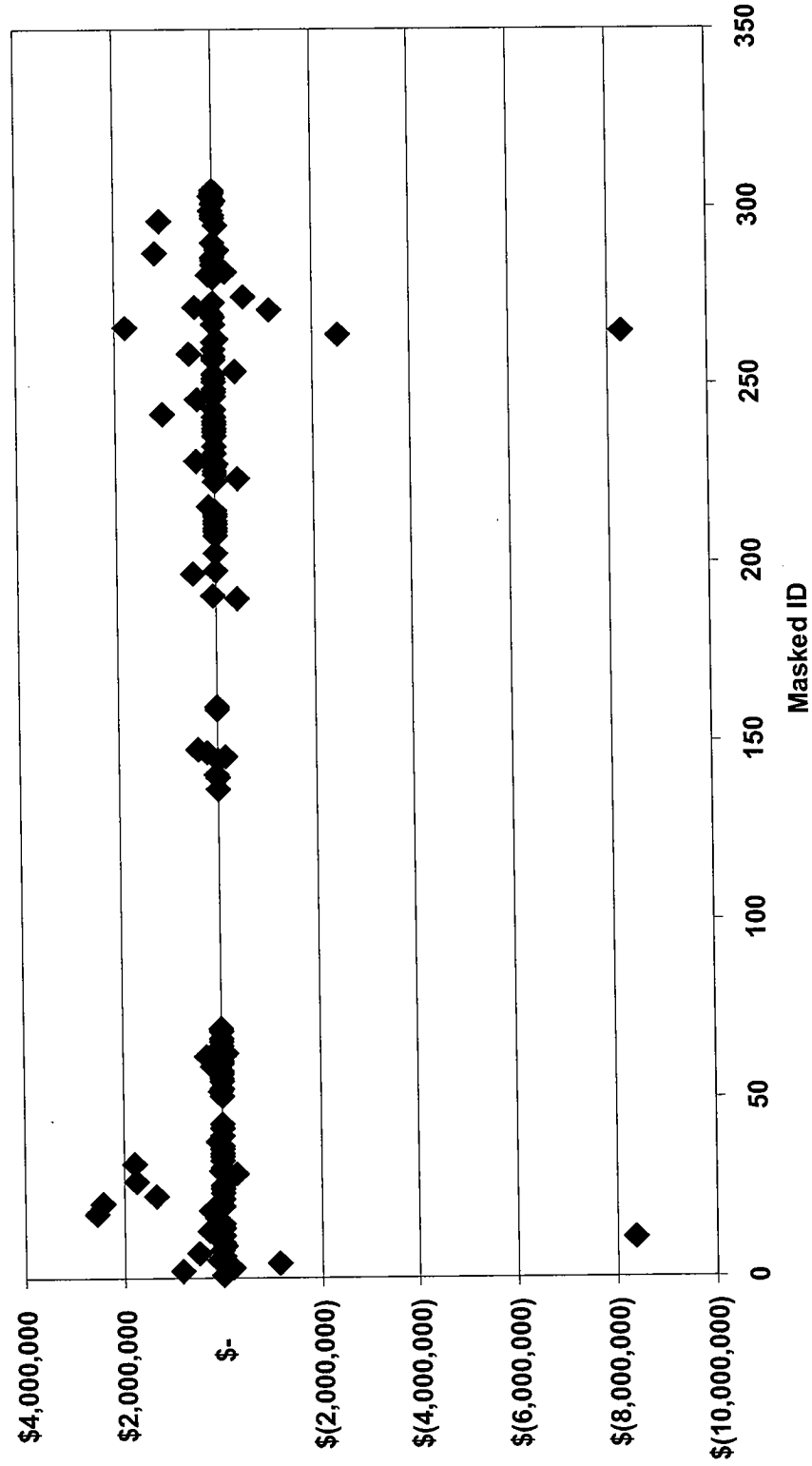


Distribution of Bill Impacts: MID 3 Proposal Option B (in thousands of dollars)



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Distribution of Bill Impacts MID 3 Proposal Option B





Evaluation Criteria

Develop a rate structure

- that meets the FERC “just and reasonable” standard, and **appropriately allocates ISO costs** among the ISO’s users.
- based on the principle of **cost causation** which charges customers for the cost of services that they use/cause;
- that is **easy to administer** (including reasonably cost effective, and benefits of change should outweigh the costs) and **understandable**;
- that **does not result in unmanageable adverse operational impacts**;
- that is arrived at through an **open and balanced stakeholder process**;
- that recovers approved ISO costs in a **stable, low risk manner** without **excess volatility**;
- that is filed with FERC by November 1, 2003, so that it can be effective January 1, 2004, and
- that meets the terms of the 2002 GMC Settlement Agreement, which set forth issues to be covered in this 2004 GMC Stakeholder Process.



Next Steps

- June 26
 - Presentations on each proposal
- July 24
 - Board approval of 2004 GMC Structure
- October 23
 - Board approval of 2004 Budget
- October 31
 - Section 205 Rate filing at FERC
- January 1, 2004
 - New Rate structure effective

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Proposed Agenda
2004 GMC Rate Structure Project
Monday, June 16, 2003
10:00 a.m. to 12:00 p.m.
Conference Call-in #1-888-788-6681 Passcode: 98563

1. Introductions/roll call
2. Updates
 - a. SCE proposal
 - b. MID proposal
 - c. ISO proposal
3. June 6 Board discussion
4. June 26 Board presentations
 - a. What to expect
 - b. Participant opinions on proposals and process
5. Bill impact analysis update
6. Discussion of timeline

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Agenda

2004 GMC Rate Structure Project

Monday, June 16, 2003

10:00 a.m. to 12:00 p.m.

Conference Call-in #1-888-788-6681 Passcode: 98563

1. Introductions/roll call
2. Updates
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 - b. MID proposal
 - c. ISO proposal
3. Discussion of SDG&E issues
4. June 6 Board discussion
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 - a. What to expect
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7. Discussion of timeline

See notes and participant list below:

Notes to conference call:

The conference call began with a discussion of the agenda for the conference call and schedule of future meetings.

David Cohen asked if a different version of the bill impacts spreadsheet could be sent out as the current version was too large and he was unable to print it.

SDG&E asked if they would have an opportunity to discuss their issues with billing determinants. An opportunity for them to do so was provided after the discussion of proposal updates.

SCE began with a brief update. They would be modifying their proposal to replace the energy charge on CAS with a demand charge. It would take a few days for him to make the change. David Cohen asked if Bert Hansen had taken the issue of a 25 percent DDES charge to his management. Bert had not, but they would be looking at it soon.

MID had no update to their proposal. When asked, MID stated that it was possible that their proposal would change in response to issues brought up by other participants. MID had decided on whether Option A or B was the correct method to use. MID wanted to have participants input prior to making that decision.

David Cohen asked if MID had reconsidered its tiered charges in the Resolving Energy Imbalances function. MID had not.

The ISO discussed updates to its proposal. No new information had been released. There were a few questions concerning the revised billing determinants.

The ISO had not yet completed compiling data through February 2003 for all billing determinants, but did state that it was likely to have all the data by the end of the week. The ISO also committed to having a revised white paper out at approximately the same time.

There was a discussion of the use of the more recent data. The ISO deferred answering that question until its legal counsel had been consulted.

SDB&E raised the issue of the SouthWest Power Link (SWPL) receiving ISO GMC charges. As SWPL was used to transmit power to IID and APS, these show up as exports and would be assessed the same charges as load and exports.

CDWR brought up the issue of the use of non-coincident peak rather than coincident peak. The ISO said that this issue could be addressed at the June 30th meeting. CDWR and their counsel discussed this briefly and agreed with the ISO that this discussion could take place then.

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LSUPDT: 06/25/03

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SDG&E was given the opportunity to raise their issues, primarily charges to exports to APS and IID over SWPL. SCE compared SWPL to the California Oregon Transmission Project. MID took issue with this characterization. There was a long discussion of the similarities or lack of similarities between SWPL, Eldorado (exports from Mohave) and COTP. There was an agreement at the end of this discussion by the parties, SDG&E, SCE and MID not to mischaracterize aspects of the respective transmission lines.

SDG&E asked if the ISO would define exports not to include exports on COTP, SWPL and Eldorado. The ISO would not at this time. SDG&E mentioned that it was willing to discuss alternative charges that would be lower than the current or proposed charges.

David Cohen asked if SDG&E would quantify the amount of MWs and MWhs that would be involved in exports from SWPL, so that participants could get an idea of potential magnitude of bill impacts. SDG&E agreed. There was a discussion of whether there were similarly situated entities. MID pointed out that there were none. SDG&E said there was no intention to bring forth a new GMC proposal, but that their discussion was meant to focus on the implementation of whatever GMC is adopted.

The ISO briefly recapped the June 6th ISO Board meeting and the direction that the Board gave at that meeting. This led to a discussion of what would be presented at the June 26th Board meeting. According to the ISO, there would be no presentations on proposals at the June 26th meeting. The ISO would make a presentation on FERC ratemaking standards. There would be no GMC action items on the agenda.

There was the possibility of a mid-July Finance Committee meeting at which proposals could be presented. However, this was not firm yet.

At the July 24th ISO Board meeting, the Finance Committee might make a recommendation to the full Board on a GMC structure and the full Board might take action.

There were some questions about the ability of participants to make comments to the Board. The ISO stated that there was always a public comment period and that parties with proposals to present would be given sufficient time to make their proposals.

At the end of the conference call, an additional conference call or meeting for July 8th was discussed. The date was set for a conference call, though David Cohen thought that a meeting might be more fruitful.

List of Participants on Conference Call

Last Name	First	Company	Telephone	E-mail Address
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Barkovich	Barbara	Barkovich and Yap		
Brommer	Mike	TID	(209) 883-8320	mtbrommer@tid.org
Cogdill	Jan	ISO		
Cohen	David	Navigant Consulting	(503) 708-7852	dcohen@navigantconsulting.com
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Yari	Ali	SDG&E		

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CALIFORNIA ISO

California Independent
System Operator

Status Report: Grid Management Charge

June 19, 2003
Market Issues Forum

Ben T. Arikawa
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(916) 608-5958

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Topics

- 2004 GMC Rate Structure Project
- Timeline

Exh. No. ISO- 307, Page 3 of 7



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2004 GMC Rate Structure Project

- ISO committed to restructuring process in 2001 GMC proceeding (ER01-313-000)
- Some issues addressed
 - A review of ratemaking principles
 - Alternative rate structures
- Goal: to develop basis for new ISO rate structure effective January 1, 2004



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2004 GMC Rate Structure Project (cont.)

- 2004 GMC Rate Structure Project web page on CAISO website
 - Documents – including meeting notes and presentations by all parties
 - Public Discussion Board
 - Confidential Discussion Board
 - Accessible from <http://www.caiso.com/docs/2002/08/02/2002080216283419989.html>

CALIFORNIA ISO Timeline

- June 6, 2003 ISO Board meeting
 - Board gave direction to ISO staff on 2004 GMC process
 - Revamped schedule
- June 26, 2003 ISO Board meeting
 - Fundamentals of ratemaking
 - No discussion of proposals



Timeline (cont.)

- June 30, 2003 GMC WG meeting
- July 8, 2003 GMC WG conference call/meeting
- ISO Board Finance Committee meeting (tentative in July)
 - Proposals to be discussed
- July 24, 2003 ISO Board meeting
 - Possible Finance Committee recommendation
 - Board action on 2004 GMC structure



Memorandum

To: Board of Governors
From: William J. Regan, Chief Financial Officer
Deborah A. Le Vine, Director of Contracts
Philip Leiber, Treasurer & Director of Financial Planning
cc: ISO Board Assistant, ISO Officers
Date: June 20, 2003
Re: *Grid Management Charge – Ratemaking & GMC History*

This memorandum is for information only.

EXECUTIVE SUMMARY

As a public utility under the Federal Power Act, the ISO develops a charge based on cost-of-service methods to recover its operating and development costs from Market Participants. This charge is referred to as the ISO Grid Management Charge, or "GMC". The ISO has been re-examining the rate methodology for the GMC due to an order from the Federal Energy Regulatory Commission and a Settlement Agreement with Market Participants. In this review, the ISO is re-examining the nature of the services it provides and the cost drivers for such services. The ISO Management will seek approval of a new rate structure at the July 26th Board meeting.

BACKGROUND

Utility ratemaking for transmission costs has traditionally been based on the cost of providing the service, or "cost-of service". For investor-owned utilities this represented the actual cost of transmission facilities and their associated services, plus a rate of return on equity. With the advent of the California ISO, a non-profit public benefit corporation, the cost-of-service approach was modified to reflect the role and structure of the firm. (For example, there is no return on equity.) The ISO began its determination of a grid charge with a cost-of-service study. To perform a cost-of-service study, the ISO first determined what services are provided. (These services are considered "functions" in cost-of-service methodology.) Costs associated with the various functions are attributed to each function, based on the nature of the function and the activities it encompasses. The functions are then classified by customers' use patterns and what costs are incurred based on the use of that function. A measure of such usage patterns must then be devised in order to have an appropriate metric for spreading the costs of the function across multiple users.

June 20, 2003

The factor that is used to characterize who uses each service and how such usage can be quantified and spread is known as the billing determinant, or the denominator in the charge. Attachment A summarizes the process of a cost-of-service study and the assignment and recovery of costs.

HISTORY OF THE GMC

In its first rate filing in 1997, the ISO proposed an all-inclusive Grid Management Charge assuming that all responsible for delivery of energy within the ISO's control area should pay for the ISO's operating and development costs. Certain parties, mainly those with existing contracts, argued they should pay only for the ISO services that they used, or some other reduced rate. They rejected the ISO's initial proposal to recover all of the ISO's costs through a single bundled, volumetric (or energy-based) rate. In 1998, the ISO reached a settlement with all paying parties that provided a discount of 50% to 100% for transmission volumes for entities with Existing Contracts. At the same time, the ISO agreed to undertake a study of how its Grid Management Charge might be recovered on an "unbundled" basis, i.e. with separate charges for its various services. In 1998, the ISO conducted such a study. However, there was little support for its recommendations, and the 1998 GMC settlement was extended, ultimately until December 2000.

From 1998 through 2000, the ISO conducted a stakeholder process that led to the ISO's first unbundled GMC, effective January 2001. The unbundled GMC consisted of three separate charges (called the "three-bucket" model), assessed on various billing determinants. That GMC structure, with some minor modifications, continues to be in effect today.¹

Table 1
Current Unbundled GMC Structure

GMC Category	Billing Determinant
Control Area Services ("CAS")	Gross Load and Exports in Volume (Megawatt Hours)
Inter-Zonal Scheduled Load renamed "Congestion Management" ("CONG") in 2002.	Net Hour-Ahead Scheduled on Inter-Zonal power flows per path in Volume (Megawatt Hours)
Market Operations, renamed Ancillary Services and Real Time Energy Operations ("ASREO") in 2002.	Purchases and Sales of Ancillary Services, and Real Time Energy (instructed and uninstructed) in Volume (Megawatt Hours)

The ISO filed this rate with FERC in November 2000. It was protested by many stakeholders who had participated in the previous stakeholder process. FERC therefore set it for hearing in 2001. The FERC Administrative Law Judge (ALJ) issued her Initial Decision on the 2001 proceeding in May 2002. The Initial Decision largely affirmed the ISO's unbundled GMC, but the ALJ specifically directed the ISO to explore further certain issues raised in the 2001 case, including: (a) greater unbundling of the Control Area Services charge (i.e. whether

¹ FERC Order 436 issued on May 2, 2003 on the 2001 GMC may provide for retroactive changes to the existing GMC structure with respect to Control Area Services assessed to "behind-the-meter" Load. The ISO has sought clarification of certain elements and rehearing of other elements of this order.

June 20, 2003

entities with load that does not access the ISO Controlled Grid should pay a portion of ISO GMC costs); (b) the potential use of demand versus energy billing determinants; and (c) Modesto Irrigation District's proposals on ISO's cost recovery, among others. Additionally, the ISO agreed to explore certain additional issues in the rate structure review process as a term of the 2002/3 GMC Settlement.

In the interim, in November 2001, the ISO made a Section 205 rate case filing for the year 2002 that proposed certain modifications to the 'three-bucket' GMC structure. The 2002 rate case was ultimately settled by direct negotiation with intervening parties and filed with FERC in October 2002. The ISO and intervenors agreed to keep the three-bucket GMC structure in place, essentially as filed in 2001, through 2003 on the condition that a new stakeholder process would be initiated that could potentially unbundle the Grid Management Charge to a greater degree.

CURRENT PROCESS

The ISO initiated the current process to evaluate further unbundling the Grid Management Charge in August 2002. To date, the ISO has hosted some twenty-five meetings and conference calls with the stakeholders. In addition, more than 1,000 e-mails have been exchanged in this process.

The process has resulted in three proposals, one each from the ISO, Modesto Irrigation District and Southern California Edison. Each of these proposals will be presented at the Finance Committee meeting in July.

NEXT STEPS

The structure of the Grid Management Charge is integral to a cogent budget process. In order to ensure the structure of the budget works with the defined Grid Management Charge, ISO Management will ask for approval of a restructured Grid Management Charge at the July 24th Board meeting.

With the approval of the Board, the ISO will use this structure in the development of the ISO 2004 budget, which will be subject to stakeholder, Finance Committee and Board review during September and October 2003. The ISO Management expects to bring the ISO 2004 budget to the Board for approval in late October. The Grid Management Charge and the budget will then be filed with FERC by October 31, 2003 in an integrated filing, so that a new rate can be effective January 1, 2004.

Summary of a Cost-of-Service Study and its Use to Allocate and Recover Costs

The **rate design** process involves determining the **charges** that will recover the costs that are associated with each of the various services (called “functions” in cost-of-service language) provided, by spreading them across an appropriate measure of the type of usage associated with each function. In other words, a charge is developed which, when multiplied by a customer's usage of an appropriate type, will recover, as closely as possible, a customer's obligation for the costs incurred providing that function. (All costs are considered recoverable in this process and the charges are set to meet the total budget of the company, in this instance, the ISO. Disputes over the level of costs are taken up in the budget process.)

A **cost-of-service study** generally looks at accounting costs, i.e., costs recorded in a utility's accounts. The ISO uses the costs in its budget to establish its cost of service.

The study first sorts all of the accounting costs (the ISO cost center budgets) into **functions**. For an electric utility, these functions would be generation, transmission, distribution, and customer services. An ISO provides a subset of traditional utility services and some new ones. A detailed analysis of the activities that cause the ISO to incur costs resulted in the identification of the following functions:

- 1) **Control Area Services**, which may be subdivided into fixed and variable-cost services. The ISO has made a proposal to split this function into:
 - Core Reliability Services -- those activities that are essential to the functioning of the ISO as a Control Area Operator in a Control Area of its size and geography, and
 - Energy and Transmission Services -- those activities that vary with the intensity of use of the Control Area
- 2) **Market Services**, which the ISO proposes to subdivide into:
 - Congestion -- the management and operation of Inter-Zonal congestion markets,
 - Market Usage -- the management and operation of the forward and Real-Time Markets, and
 - Scheduling -- the forward scheduling of Energy and Ancillary Services and the processing of accepted Ancillary Services bids, and

- 3) **Settlements, Metering and Client Relations**, which includes those activities relating to interaction with ISO customers.

All customers in the Control Area use the ISO Control Area services to some degree, since the ISO keeps supply and demand in balance and manages the transmission grid to avoid congestion and line overloads. Only one entity can do this. However, not all customers use these services to the same extent. Similarly, not all customers use the ISO market services, but all interact with the ISO as customers, since they receive bills and settlement statements, make account inquiries, and ask other questions.

Classification of Costs

The next part of the process is to identify the usage patterns that drive the costs associated with the functions. This process is called **classification**. For some purposes, the ISO's costs are driven by the need to meet the maximum instantaneous usage of the Control Area by any and all participants. Others are driven by how the services are used over time and how much customers deviate from what they have scheduled. Still others are driven by the numbers of customers the ISO has. These usage patterns determine who is responsible for the ISO's costs and thus how these costs are to be allocated among customers. They also provide the basis for billing the customers for the recovery of these costs.

The functions are classified as to whether they relate to:

- Demand (i.e. instantaneous use of the Control Area at any given time or at the time of system peak),
- Energy (i.e. cumulative use of the Control Area over time and often referred to as "Load"), and/or
- Customer (i.e. interaction with the customers, in this case, Scheduling Coordinators) costs.

Billing Determinants

The actual usage patterns that define the classification are used to develop what are called billing determinants. These include kW of instantaneous Demand (either the maximum at any time (non-coincident peak) or, for some purposes, at the time of system peak (coincident peak)), kWh of Energy (volumetric usage of the system), and number of customers. The kWh of Energy can be net or gross (i.e. they can include

load behind-the-meter or not) or they can be assessed, if appropriate from a cost causation perspective, in terms of what the customer has scheduled (e.g. as deviations from the final schedule). The billing determinants are the measurements of usage, which will be used to bill the customers for the costs they have been allocated.

Assignment of Costs

It is not always easy to determine which costs are most appropriately assigned to each service or function, or which type of usage best characterizes responsibility for these costs. Some assignments are inherently difficult. For example, the scheduling infrastructure systems are mainly used to schedule but also are used to process Ancillary Services bids and for Congestion Management. The latter category are called **joint costs**, in that the fixed (investment) costs of the system support three functions. In such cases some degree of judgment must be used in assigning the costs of the investment to the different functions, since systems were not developed on an individual functional basis and the costs were not tracked that way. Similarly, the infrastructure and personnel providing control area services must include the equipment and staff to provide some services instantaneously (e.g. assuring that the transmission lines are not overloaded or that there is check-out at the interties) regardless of how intensively the Control Area is being used at any given hour and to do so 24 hours a day. At the same time, the number of personnel needed for Control Area services will vary with the amount of activity taking place at a particular time. For instance, when the level of imports and exports is high, there is significantly greater check-out activity with adjacent Control Areas, which may be accompanied by contingencies that increase the amount of effort required to complete each check-out.

Finally, there are **overhead costs**, such as general and administrative costs, that can only be assigned on the basis of some convention, generally referred to as "allocation". These costs may only be very indirectly associated with specific ISO activities, but ultimately support all ISO functions. An allocation may assign overheads on the basis of total dollars, labor costs, or some combination of factors. The more costs that can be directly assigned to functions the better, but there will always be costs, such as human resources management, information systems support, etc., that are shared throughout the organization. Therefore, some costs will always be allocated as overhead.

Board contact list 06-24-03 .txt

From: Arikawa, Ben
Sent: Tuesday, June 24, 2003 8:35 AM
To: Pritchard, Jan
Subject: Board contact list

Board contact list

<http://www.caiso.com/docs/09003a6080/0b/45/09003a60800b4585.pdf>

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Additional contact info 06-24-03.txt

From: Arikawa, Ben
Sent: Tuesday, June 24, 2003 9:02 AM
To: Pritchard, Jan
Subject: Additional contact info

Here is additional contact info. No phone numbers, but names.

<http://www.caiso.com/pubinfo/BOG/info/staff/>

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GMC Rate Structure

June 26, 2003
ISO Governing Board

Debi Le Vine

Disclaimer: The details contained herein are subject to change as part of an ongoing review process, therefore, the ISO does not represent this information is either complete or final. Any references to other entities GMC structure proposals are not warranted as accurate, are intended as informational summaries only and do not represent an endorsement by the ISO of such proposals.



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Summary of Presentation

- What is the GMC?
- Ratemaking Criteria
- Current GMC and History
- Why Change the GMC Structure Now?
- Schedule



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What is the GMC?

The Grid Management Charge is a monthly charge to all Scheduling Coordinators that provides for recovery of ISO costs for services provided.



The “Cost of Service” Concept

- Define services/functions ISO provides
- Determine activities for each function
- Assign costs for each function
- Determine how to recover costs fairly



Ratemaking Criteria

- Based on principle of cost causation
- Stable, low risk cost recovery
- Understandable and easy to administer
- No adverse operational impacts
- An open and balanced development process
- Meets FERC “just and reasonable” standard

Current GMC Structure

Function	Example of Activities	% of ISO Costs	Billing Determinants
Control Area Services	Reliable Operation of Grid, Coordination w/other Control Areas, Outage Coordination, etc.	58%	Gross Control Area Load & Exports in MWh (volumetric) (5/2/2003 FERC order modifies for behind the meter load for QFs, Munis)
Congestion Management	Manage inter-zonal congestion.	12%	Net Inter-Zonal scheduled load in MWh (volumetric) (Existing Contracts are exempted)
Ancillary Services and Real Time Energy Operations	Administering Energy and Capacity Markets, Market Surveillance, Publishing Market Information, etc.	30%	Purchases and sales of ancillary services and real time energy, including uninstructed deviations (at a resource-level) in MWh (volumetric)

CALIFORNIA ISO



Indicative Monthly Invoices

California Products

1124 7th St.

Mead, CA 95459

Invoice: 24600

Date: MAY-22-2003

BAID: 9500

Charges for Settlement Dates: 01-MAR-03 to 31-MAR-03

Charge Type:	Description	Amount
0001	0001 - Day Ahead Spinning Reserve Due SC	-\$5,370.00
0005	0005 - Day Ahead Regulation Up Due SC	-\$612,890.41
0051	0051 - Hour Ahead Spinning Reserve Due SC	\$1.69
0056	0056 - Hour Ahead AGC/Regulation Down Due SC	-\$281,900.09
0401	0401 - Instructed Energy	-\$515,000.00
0406	0406 - UFE Settlement	\$28,500.50
0407	0407 - Uninstructed Energy	\$489,500.60
1061	1061 - Distribution of Preempted Spinning Reserve	-\$11.60
1121	1121 - Act. Summer Reliab. Contract Capacity Pymt/Charge	-\$1305.80
1302	1302 - Long Term Voltage Support Contract Due ISO.	\$1,840.50

Market Invoice Total:

-\$896,634.61

521	0521 - GMC Control Area Services	\$318,569.98
522	0522 - GMC Congestion Management	\$15,275.02
524	0524 - GMC A/S and RT Energy Operations	\$227,300.00

GMC Invoice Total:

\$561,145.00

Payment Due Date: 30 - MAY - 2003



What costs are recovered by the GMC?

- Grid Management Charge (GMC) rates are set to collect the ISO net annual operating costs, or “Revenue Requirement”

• 2003 Revenue Requirement:	
• O&M budget	\$171.8 million
• Capital budget	\$ 22.0 million
• Debt service	\$ 43.8 million
• Operating reserve	\$ 2.7 million
• Other	<u>(\$ 2.7 million)</u>
» Total	\$237.6 million



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GMC History

•1997-1998

- “Bundled” GMC implemented as a result of Settlement Agreement approved by FERC. Discounts are provided for existing contract load, and ISO instructed to initiate open review process for GMC. Settlement extended through 2000.

•2001

- ISO files and implements “unbundled” rates, developed through an extensive stakeholder process. Rates are effective for GMC, but filing is set for hearing and rates are subject to refund

•2002

- FERC ALJ decision on 2001 GMC Rate Case favorable to ISO, but directs stakeholder process to consider new Unbundled GMC Rate Structure for 2004
- 2001 Unbundled Rate Structure continued with minor modifications that were eliminated in 2002 Settlement Agreement

•2003

- 2002 Settlement continued. FERC decision on 2001 GMC mostly supportive of ALJ Initial Decision



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GMC Process and the ISO Budget

- Develop GMC Rate Structure
- GMC Rate Structure approved by Board
- Develop Corporate and Department Goals
- ISO Budget structured to implement Goals
- Budget and goals approved by Governing Board
- 2004 Budget and the approved GMC Rate Structure combined in October 2003 FERC filing
- 2004 Budget as filed with FERC implemented through the GMC Rate Structure



Why Re-evaluate GMC Structure?

- External
 - 2001 GMC Rate Case Initial Decision/Order
 - Requires ISO to *evaluate further unbundling*
 - *Address issues raised by stakeholders*
 - *Requires evaluation of alternative proposals*
 - Stipulated in the 2002 Settlement.
- Internal
 - MD02 changes force changes to GMC structure
 - Most significantly, forward market and LMP
 - *Better reflects services provided and costs for service*
 - *Address certain deficiencies in current GMC structure*
 - *It's the right thing to do given the changing environment*



Stakeholder Process

- Commencement: *August 2002*
- *August 2002 – June 2003*
 - Approximately 25 meetings and conference calls
 - Numerous active participants
 - Over 1000 e-mails
 - Currently 3 proposals
- Timeline provides for Board action by *July 2003*
 - ISO budget to be reviewed/approved by Board during September/October
 - Rate filing in late October



Next Steps

- July 17, 2003
 - Finance Committee review of alternative GMC proposals
- July 24, 2003
 - Board approval of 2004 GMC Rate Structure
- October 23, 2003
 - Board approval of 2004 Budget / Rate Filing
- October 31, 2003
 - Section 205 Rate filing at FERC
- January 1, 2004
 - New Rate structure effective



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ISO Proposed 2004 Service Categories

Function	Description
Core Reliability Services	All necessary activities attributable to reliable operation of a Control Area including the capability of handling a system that is as geographically dispersed as the present system, but without features that are scalable.
Energy & Transmission Services	Scalable portion of Control Area operations.
Forward Scheduling	Provides SCs with ability to forward schedule energy and Ancillary Services.
Congestion	Management and operation of inter-zonal congestion markets.
Market Usage	Markets for supplemental energy and Ancillary Service bids, Open Access Same-Time Information System (OASIS), market monitoring & performance.
Settlements, Metering, Client Relations	Interface to scheduling coordinators through metering, settlements, and client relations.



2004 GMC Rate Structure Project Briefing

To: Participants in 2004 GMC Rate Structure Project
From: Ben T. Arikawa, Senior Financial Analyst
Date: June 27, 2003
Re: 2004 GMC Rate Structure Project related items

This Briefing contains:

- New documents;
- An update on data availability;
- June 26th Board presentation on GMC; and
- Meeting schedule for July.

New documents

The agenda and materials for the June 30th meeting at the ISO in Folsom have been posted on the GMC main page: <http://www.caiso.com/docs/2003/02/07/2003020716402314262.html>.

Earlier today, we have distributed additional materials for the confidential session discussion of cost assignments to individuals on the Confidential Agreement Registry kept by Stephen Morrison. If you did not receive them, please let me know.

The notes (with edits from MID) to the May 28th conference call have been posted to the GMC main page also.

The draft notes to the June 4th meeting and the June 16th conference call have been posted to the public discussion board located at: <http://www1.caiso.com/discus/messages/875/875.html>. Please review the notes for consistency and clarity. Let me know if you have any edits to the notes by July 7th. I will post them on or about the 8th.

Update on data availability

We have compiled almost all of the data needed to analyze each proposal through February 2003. On June 30th, we will be making a presentation on data stability using some of this updated data. Once all the needed data is compiled, we will post an updated aggregated billing determinant spreadsheet to the public discussion board and reissue the billing impacts spreadsheet.

June 26th Board presentation on GMC

Created By: Ben Arikawa

LST UPDT: 06/27/03

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Debi Le Vine gave a presentation before the ISO Board yesterday, June 26th. Her presentation can be found at this link: <http://www.caiso.com/docs/2003/06/20/2003062014143226129.html>. Scroll down to item 6.

Laurence Kirsch made some brief comments before the Board in the public comments session at the beginning of the Board meeting.

Meeting Schedule for the end of June and July

The next meeting of the 2004 GMC Rate Structure Project is scheduled for Monday, June 30, 2003 at the ISO in Folsom from 10:00 am to 3:00 pm. The agenda and materials were distributed on Wednesday, June 25th and are posted on the GMC main web page.

The ISO Board Finance Committee meeting is July 17, 2003 from 9:00 am to 12:00 pm at the ISO in Folsom. We anticipate that proponents of proposals will be given an opportunity to present their proposals to the Finance Committee. We will discuss what we know about the agenda at the Monday, June 30th meeting.

The ISO Board will be asked to make a decision on the new GMC rate structure to be in effect for 2004 at the July 24, 2003 Board meeting at the ISO in Folsom.

If you have any questions about any of the information contained in this memorandum or about the process, please do not hesitate to contact:

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Proposed Agenda
2004 GMC Rate Structure Project
California ISO, Folsom
Monday, June 30, 2003
10:00 a.m. to 3:00 p.m.

Public Session (10:00 am – 12:45 pm)
Conference Call-in #1-888-788-6681 Passcode: 98563

1. Introductions/roll call
2. Updates
 - a. SCE proposal
 - b. MID proposal
 - c. ISO proposal
3. SDG&E issues
4. ISO topics
 - a. Discussion of use of non-coincident peak
 - b. Discussion of functional association of charge types
5. Discussion of timeline

Over lunch

6. Data
 - a. Billing determinant stability
 - b. Data verification

Confidential Session (1:00 pm – 3:00 pm)
Conference Call in #

7. Discussion of cost allocation method
8. Bill impact analysis update



CALIFORNIA ISO

California Independent
System Operator

California ISO

**Rate Structure Proposal
For the
2004 GMC Rate Structure Project
DRAFT**

**Project Co-Leads:
Phil Leiber
Debi Le Vine**

Revised June 25, 2003

California ISO Draft White Paper on Rate Structure Proposal
Revised June 25, 2003

1.0 Introduction

This document and its appendices detail the California Independent System Operator's alternative rate structure proposal as part of the 2004 GMC Rate Structure Project to redesign the structure of its Grid Management Charge (GMC) in accordance with the Initial Decision in ER 01-313-000, *et. al.* and the Settlement Agreement in ER 02-250-000, *et. al.*. They also serve to describe and record the efforts of the California Independent System Operator (California ISO) in developing the proposal.

In developing this proposal, the California ISO and participants reviewed the rate structures of other North American Independent System Operators, FERC ratemaking standards and traditional and marginal cost ratemaking methodologies. In addition, the California ISO worked with participants to review the California ISO's current GMC structure and cost accounting methods and to develop a comprehensive listing of California ISO activities. The California ISO and participants also worked together to develop a list of potential billing determinants for use by any party in developing their own proposal.

The California ISO adopted, where possible, reasonable and appropriate concepts put forth in other parties' rate proposals. The California ISO also took note of the imperatives of the Initial Decision to unbundle California ISO rates, consider demand charges, and to look at alternative methods of cost assignment of certain cost centers.

The California ISO also kept in mind the following criteria from the 2004 GMC Rate Structure Project Charter:

- Develop a rate structure that meets the FERC "just and reasonable" standard, and appropriately allocates ISO costs among the ISO's users;
- Develop a rate structure based on the principle of cost causation, which charges customers for the cost of services that they use/cause;
- Design a rate structure that is easy to administer (including reasonably cost effective, and benefits of change should outweigh the costs) and understandable;
- Develop a rate structure that does not result in unmanageable adverse operational impacts;
- Develop a rate structure that is arrived at through an open and balanced stakeholder process;
- Recover approved ISO costs in a stable, low risk manner without excess volatility;
- Have the new rate structure filed with FERC by November 1, 2003, so that it can be effective January 1, 2004; and,
- Meet the terms of the 2002 GMC Settlement Agreement, which set forth issues to be covered in this 2004 GMC Stakeholder Process.¹

¹ **2004 GMC Rate Structure Project, a Stakeholder Process**, (project charter) page 2.

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2. Summary of Proposal

Table 1 Summary of the California ISO Rate Proposal Functionalization and Billing Determinants						
Function	Grid Reliability Services		Market Services			Settlements, Metering and Client Relations
Sub-Function	Core Reliability Services	Energy and Transmission Services	Forward Scheduling	Congestion Management	Market Usage and Services	
Billing Determinant	Non- coincident peak demand (MW)	(1) ISO Controlled Grid Load plus exports and (2) absolute value of net uninstructed deviations by settlement interval MWh	Final HA schedules submitted, no charge for changes to DA schedules	Net Scheduled Interzonal flows MWh	Purchases and sales of Ancillary Services, instructed energy and absolute value of net uninstructed deviations by settlement interval MWh	(1) Fixed monthly charge per customer (2) Remaining costs to be recovered by association with other billing determinants

The table above summarizes the functionalization aspect of the California ISO rate proposal. The Grid Management Charge would consist of three functions. Two of the functions would be sub-functionalized. These functions, with their associated sub-functions are:

1. Grid Reliability Services
 - a. Core Reliability Services
 - b. Energy and Transmission Services
2. Market Services
 - a. Forward Scheduling
 - b. Congestion Management
 - c. Market Usage and Services
3. Settlements, Metering and Client Relations

These are described more fully below.

2.1 Grid Reliability Services

The California ISO provides for the safe, reliable operation and maintenance of the Control Area, provides for transmission expansion planning coordinates with neighboring Control Areas, manages transmission flows and complies with regional and national reliability standards.

The following is a partial listing of activities in Grid Reliability Services (a more complete list is in Appendix A):

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- Monitoring of system conditions and dispatching to maintain reliability
- Coordination, communication, and integration with neighboring Control Areas
- Intertie scheduling
- Compliance with reliability standards
- Transmission and generation outage coordination
- Management, monitoring and approval of new generator interconnections
- Evaluation of transmission expansion
- Performance of operational studies, system security analyses and system planning studies to ensure overall reliability

Portions or all of the following systems can be attributed to Grid Reliability Services:

- Energy Management System (EMS)
- Bill's Interchange Transaction Management System (BITS)
- Out-of-Sequence and Out-of-Market Settlements Information System (OSMOSIS)
- Global Reliability Resource Management Application (GRMMA)
- Automated Dispatch System (ADS)
- Scheduling Logging for the ISO of California (SLIC)
- Generator Communication Project (GCP)
- Electronic Tagging (ETAG)

The Grid Reliability Services function consists of two sub-functions, Core Reliability Services and Energy and Transmission Services.

2.1.1 Core Reliability Services

The California ISO provides a basic level of reliable operation of a Control Area surrounded by other control areas and achieving minimal disruptions to system operation. In this sub-function, the California ISO provides a stable grid and meets regional and national regulatory requirements (such as NERC and WECC reliability criteria) and some FERC requirements (such as a basic level of transmission planning). All necessary activities attributable to Control Area operation including the capability of handling a system that is as geographically dispersed as the present system, but without features that are scalable (i.e., that vary according to use or size of flow) are contained in this function. However, only a basic level of activity is contained in this service. The level of activity does not represent fully functioning operations for a robust Control Area in which there are outages and growth as new generation and transmission projects are developed.

These services must be constantly available in order for the Control Area to operate reliably and must reflect the fact that the Control Area is interconnected with and interacting with other Control Areas and in compliance with all regulatory mandates placed on it.

Included in the costs of these services are the costs of systems applications necessary to operate the Control Area.

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The charge to recover the costs of this service would be assessed on the metered non-coincident peak (NCP) demand of Scheduling Coordinators (SCs) on a monthly basis. The ISO is no longer proposing to calculate a separate adder for behind the meter Standby Load and behind the meter load of other entities. At this time, the ISO is waiting for the final Commission decision in the QF PGA, ER98-997-000 to determine how SCs may comply with the metering requirements of the ISO Tariff.²

2.1.2 Energy and Transmission Services

The California ISO provides for the safe, reliable operation of the Control Area assuming everyday (normal and extraordinary) operational requirements in which outages and disruptions (such as weather-related incidents) occur. This is the scalable portion of Grid Reliability Services that is necessary to respond to the everyday occurrence of system activity.

The level of activity is a function of the intensity of use of the transmission system within the Control Area and the occurrence of system outages and disruptions (e.g., weather-related incidents). This includes the services for simultaneously managing energy imbalances and transmission flows beyond those in a steady state Control Area.

For example, grid planning requires more resources in a control area that has growing load and significant need for new transmission and generation facilities. The use of the grid will be more intense if load-serving entities generate only part of their own power and buy part, bringing it to load centers through the grid within the Control Area. A higher level of uninstructed deviations will increase the workload of the California ISO, since actions must be taken to offset these deviations to ensure system-wide balance in real time.

Included in the costs of Energy and Transmission Services are the scalable portion of systems applications and the hardware necessary to operate the Control Area.

In this sub-function, the level of activity within the Control Area drives costs. Thus, they will vary with the volume of flows and the level of net uninstructed deviations within a settlement period. Two volumetric billing determinants will be used: monthly ISO Controlled Grid Load³ plus exports (MWh) and the absolute value of net uninstructed deviations by settlement interval (in MWh).

2.2 Market Services

² The ISO Tariff requires SCs to schedule and meter gross demand and generation. However, the ISO waived this requirement for Qualifying Facilities pending a final FERC decision in ER98-997-000. An Initial Decision has been issued, but the Commission has not yet voted to affirm that decision.

³ The ISO Controlled Grid includes the system of transmission lines and associated facilities of the Participating Transmission Owners that have been placed under the ISO's Operational Control.

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Under Market Services, the California ISO provides access to its scheduling infrastructure, manages congestion to facilitate transmission flows, operates and maintains California ISO markets for participants, and monitors market performance.

Contained in this function are activities related to the maintenance, monitoring, operation and performance of the forward and Real-Time markets. These activities span many of the activities within the ISO's current Congestion Management and Ancillary Services/Real-Time Energy Operations services.

The following is a partial listing of activities in Market Services (a more complete list is found in Appendix A):

- Processing forward market schedules
- Adjusting forward market schedules to mitigate transmission congestion
- Maintaining market information postings
- Operating Real-Time market
- Determining market clearing prices
- Administering primary and secondary Fixed Transmission Rights markets
- Monitoring market performance

Portions or all of the following systems can be attributed to Market Services:

- Scheduling Infrastructure (SI)
- Scheduling Applications (SA)
- Open Access Same-Time Information System (OASIS)
- Automated Dispatch System (ADS)
- Balancing Energy Ex-Post Pricing (BEEP)
- Automated Load Forecasting (ALFS)
- Firm Transmission Rights (FTRs) and Secondary Registration System (SRS)
- Outage Scheduler (OS)
- Existing Transmission Contracts (ETC)
- Congestion Management (CONG)
- Day Ahead Data Analysis Tool (DADAT)
- Hour Ahead Data Analysis Tool (HADAT)

The Market Services function consists three sub-functions, (1) Forward Scheduling, (2) Congestion Management, and (3) Market Usage and Service.

2.2.1 Forward Scheduling

The California ISO provides SCs with the ability to forward schedule energy and Ancillary Services and the processing of accepted Ancillary Services bids. In this context, a schedule is represented by a scheduling template (import, export, load, generation, inter-SC trade and

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Ancillary Services, including self-provided AS) submitted to the California ISO's Scheduling Infrastructure.

The following is a partial listing of activities in Forward Scheduling:

- Processing forward energy schedules, including inter-SC trades
- Reviewing and verifying schedules

The ISO processes schedules to confirm path ratings are not exceeded, to ensure that sufficient Ancillary Services are or will be procured and that SC portfolios are balanced.

The costs incurred by the California ISO are more closely correlated with the number of schedules than energy volumes, since the basic effort encompasses processing the schedules and bids regardless of the volume within the transactions. The billing determinant will be the number of final hour-ahead schedule templates submitted, not including changes to the DA schedule (so as not to discourage load-following).

2.2.2 Congestion Management

The California ISO provides management and operation of inter-zonal congestion markets, using adjustment bids, taking Firm Transmission Rights and Existing Transmission Contracts into account, and determining the price for mitigating congestion for flows on congested paths. Congestion exists when power flowing on a transmission path exceeds the transmission path capacity. Congestion management is conducted by the California ISO during the scheduling process and results in the economic rationing of transmission service in order to prevent congestion. This currently provides for only inter-zonal congestion. Intra-zonal congestion is managed in real-time and thus incorporated in Core Reliability Services.

This service is similar to the CONG service in the current GMC rate design, but is not identical due to the other changes in this proposed rate design. When LMP is implemented, congestion management activities will be functionalized and their associated costs will be assigned to other service categories, eliminating this service category.

The costs of this service would be recovered through an assessment on net Hour-Ahead scheduled inter-zonal flows (loads).

2.2.3 Market Usage

In this sub-function of Market Services, the California ISO processes supplemental energy and Ancillary Service bids, maintains and controls the Open Access Same-Time Information System (OASIS), monitors market performance, ensures generator compliance with market protocols, and determines market clearing prices. In the future, activities associated with forward energy markets will be included here.

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The following is a partial listing of activities in Market Usage and Service (a more complete list is in Appendix A):

- Maintaining market information postings
- Operating Real-Time market
- Determining market clearing prices
- Monitoring market performance

The costs of this service would be recovered through a per MWh charge on purchases and sales of Ancillary Services, instructed energy and the absolute value of net deviations by Settlement interval by SC ID. Self-provided Ancillary Services would not be assessed this charge.

2.3 Settlements, Metering and Client Relations

Under Settlements, Metering and Client Relations, the California ISO maintains customer account data, provides account information to customers, responds to customer inquiries, calculates market charges, processes settlement statements, resolves customer disputes and provides customer training. This function includes Settlements, Billing, and Metering activities as well as Client Relations. Certain Settlements activities and some Contracts and Special Projects activities are assigned to Core Reliability Services. For example, RMR Settlements is assigned to CRS because its activities are related to the maintenance and provision of RMR services to the Control Area. Similarly, Contracts and Special Projects has a primary role in the administration of the Transmission Access Charge and the development of Metered SubSystems.

The following is a partial listing of activities in Settlements, Metering and Client Relations (a more complete list is in Appendix A):

- Determine charges associated with transmission services, forward market schedules, Real-Time balancing market, congestion management and administrative charges
- Maintain and process Settlements data
- Perform Settlement statement re-runs
- Manage and monitor SC credit and collateral
- Collect and validate meter data
- Provide ISO Tariff guidance to Market Participants
- Facilitate resolution of Market Participant issues
- Provide training to Market Participants

Portions or all of the following systems can be attributed to Settlements, Metering and Client Relations:

- Out-of-Sequence, Out-of-Market Settlements Information System (OSMOSIS)
- Balance of Business Systems (BBS)
- Meter Data Acquisition System (MDAS)

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Settlements, Metering and Client Relations activities are essential to maintaining any connection between the SCs and the California ISO, regardless of the actual degree of service taken from the California ISO. It can be seen that there are major costs associated with this function. Thus, the mitigation of the bill impacts of assigning these costs on a per customer basis is essential and appropriate. For that reason, the California ISO proposes to recover these costs using both a small fixed monthly charge and a variable charge.

The fixed monthly charge is \$500 per SC ID. The remaining Settlements, Metering and Client Relations costs will be associated with the billing determinants of Energy and Transmission Services, Congestion Management and Market Usage. The billing determinants for these services are ISO Controlled Grid Load plus exports and net uninstructed deviations (Energy and Transmission Services), net scheduled interzonal flows (Congestion Management) and purchases and sales of Ancillary Services, instructed energy, and net uninstructed deviations (Market Usage). We made the decision not to associate costs to either Core Reliability Services or Energy and Transmission Services as these were new rates and any additional costs would increase the severity of bill impacts.

In order to associate the remaining costs with the other billing determinants, Barkovich and Yap and the ISO reviewed the occurrence of charge types in Settlement Statements over the test year period, September 2001 through August 2002. The occurrence of charge types in Settlement Statements is a measure of the activity flowing through Settlements. We associated each charge type with one of the three services above. The Settlement, Metering and Client Relations costs associated with each billing determinant were proportional to the relative number of charge types associated with each service. This association is detailed in Appendix C.

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3.0 Comparison to Other ISOs/RTOs

Comparisons with other ISOs are difficult as there is no standard for ISO rates. It is also made difficult by the application of the FERC Uniform System of Accounts that were created for application to traditional integrated electric utilities. Nonetheless, in the following we attempt to make some high level comparisons between the California ISO's proposed new rate structure and that of other ISOs/RTOs. These comparisons are shown in Appendix B, in which we compare ISO functions and the method of recovery.

3.1 Grid Reliability Services

Of the five other ISOs (ISO-NE, NYISO, PJM, ERCOT and MISO), only ISO-NE and PJM have "Reliability" functions. ISO-NE's Schedule 3, Reliability Administration, appears to be similar to the California ISO's proposed Grid Reliability Services function. ISO-NE's billing determinant is non-coincident peak demand.

PJM's reliability functions are Schedule 9-1, Control Area, Schedule 9-5, Regulation and Frequency Response, and Schedule 9-7, Capacity and Resource Obligation Management. Schedules 9-1 and 9-5 are recovered through MWh assessments. Schedule 9-1 is recovered through an assessment on point-to-point and network integration services flows in MWhs. Schedule 9-5 is recovered through an assessment on PJM regulation and scheduled regulation, including self-scheduled regulation. Schedule 9-7 is allocated to PJM East and PJM West by their relative non-coincident peaks. Within each region, the cost is recovered by an assessment on resource obligations in MW-days.

3.2 Market Services

Of the other ISOs/RTOs, only ISO-NE and PJM have separate market functions. The market functions of the ISO-NE can be found in Schedule 1-Scheduling, System Control and Dispatch and Schedule 2-Energy Administration. Schedule 1 costs are recovered through an assessment on "monthly Network load in kW plus the highest amount of reserved capacity of point-to-point transmission plus the highest amount of authorized use." Schedule 2 costs are recovered by assessments on Transaction Units (bilateral contract block hours plus generator block hours plus net deviation block hours) and on load and injections (generation). Fifteen percent of the Schedule 2 costs are recovered from Transaction Units and 85 percent from load and injections.

The market functions of PJM can be found in Schedule 9-4-Market Support, and Schedule 9-3-Fixed Transmission Rights. Market Support costs are recovered from generation and load MWhs. Fixed Transmission Rights costs are recovered through a charge on FTR MW per hour summed over hours. (Essentially, this converts the FTR MWs to MWhs over the year.)

3.3 Settlements, Metering and Client Relations

None of the other ISOs/RTOs have an explicit, separate Settlements, Metering and Client Relations function. All except the MISO have annual fees. These fees are described in

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Appendix B. ISO-NE, PJM and ERCOT have fixed annual fees varying from \$2,000 (ERCOT) to \$5,000 (ISO-NE and PJM). The NYISO and the Ontario IMO have tiered fees that vary by the amount of load an entity has. The NYISO has a \$5,000 fee for all other companies that do not have load.

3.4 Startup Costs

Only the NYISO has explicit recovery of start-up costs. For 2003, the monthly amount recovered is \$1,095,881. This amount is assessed equally to customers receiving transmission services under the Open Access Transmission Tariff (OATT) and to customers receiving Location Based Marginal Pricing (LBMP) market services. The current rate for those receiving service under the OATT is \$0.046223 per MWh, and the current rate for those receiving LBMP service is \$0.047346 per MWh.

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4.0 Cost Assignment Process

The process of identifying and assigning costs to functions and sub-functions was an iterative one. As the California ISO proposal developed, the California ISO's consultants, Barkovich and Yap, Inc., reviewed the current method of cost assignment using the Budget Tool and the resulting structure in the Cost Allocation Matrix (CAM). They then laid out a process in which directors and managers of directly assignable cost centers were asked to assign costs to the California ISO's proposed functions and sub-functions, ultimately to provide data for the ISO's Cost Allocation Matrix

Each set of directors and managers provided three major items. First, they provided a description of their cost center activities to each function or sub-function. Second, they assigned their personnel to the function or sub-function. Finally, they provided a justification of their personnel assignments. The results were tabulated in worksheets, which form the basis for the direct personnel assignments in the CAM.

Barkovich and Yap worked directly with most of the directors and managers, querying results, asking for clarifications, and compiling results. In most cases several meetings and conference calls were required before personnel assignments were completed.

For those cost centers that were not directly assignable, several different methods of assignment were used. The main methods were proportional to:

- Supervised cost center assignments;
- Departmental cost center assignments;
- Total directly assigned operating costs; or
- Total operating cost assignments.

The cost assignment of capital expenditures followed a method similar to that done for cost centers. Whenever possible, capital expenditures were directly assigned. This assignment was done in an iterative process by the directors and managers of the cost centers that utilized the systems. For those capital expenditures that could not be directly assigned, one of the methods in the list above was used.

The results of the cost assignments were linked to the CAM to create the revenue requirements for each function or sub-function. The resulting assignments are shown in the table below:

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Table 2 Revenue Requirements by Function	
Grid Reliability Services	
Core Reliability Services	\$ 93,544,836
Energy and Transmission Services	\$ 38,337,665
Total Grid Reliability Services	\$ 131,882,501
Market Services	
Forward Scheduling	\$ 19,039,848
Congestion Management	\$ 10,017,448
Market Usage	\$ 28,775,078
Total Market Services	\$ 57,832,374
Settlements, Metering and Client Relations	\$ 47,885,496
Total Revenue Requirement after application of reserve	\$ 237,600,371
Revenue requirements shown are based on 2003 Budget information. Cost assignments are preliminary. Further refinement may cause these assignments to change, and allocations will vary as a result of differing costs in the 2004 revenue requirement.	

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5.0 Billing Determinants For Each Service

The California ISO and participants identified a number of potential billing determinants for use by participants and the California ISO early in the Project. This was done to allow the California ISO to begin collection of data and to prevent a lack of data from impeding progress on consideration of alternative rate designs. These billing determinants are listed in:

<http://www.caiso.com/docs/09003a6080/1e/f7/09003a60801ef7fb.pdf>.

As the California ISO proposal developed and the rate functions crystallized, we analyzed the various potential billing determinants for their suitability for use. This suitability analysis looked at two factors. We preliminarily determined if the billing determinant was causally related to the function for which it was to be used. Then we considered the billing determinant's potential stability, impact on operations and market participant behavior, and its availability in the Settlements system.

Based on this assessment, the California ISO determined that looking beyond the initial list of potential billing determinants was necessary. We found that certain transaction data were suitable for use as a billing determinant. This transaction data is discussed below.

5.1 Core Reliability Services

Core Reliability Services are the basic services needed to manage the Control Area reliably and safely. The billing determinant for this function should be reflective of the costs of maintaining operational control at all times of the day and seasons of the year, as well as the stress that entities place on the transmission system. The billing determinant selected is the monthly non-coincident peak (NCP) *demand* on a gross basis. An entity's NCP demand reflects the burden that the entity places on the operation of the transmission system.

Staff rejected use of an entity's coincident peak (CP) demand as the billing determinant. The coincident peak demand would not reflect the burden on system operation of entities whose peaks are not coincident with the system peak. Core Reliability Services must be provided at all times of the day, even to entities that have NCP demand occurring in the middle of the night.

5.2 Energy and Transmission Services

Contained within Energy and Transmission Services is the scalable portion of Grid Reliability Services. Scalability implies an increasing relationship with flows, outages and disturbances within the Control Area. The costs of managing the Control Area will be higher to the extent that total flows increase. They will also be higher to the extent that entities cause inadvertent flows that must be managed in real time. The billing determinants selected by the California ISO are the monthly ISO Controlled Grid Load plus exports and the absolute value of net uninstructed deviations by Settlement interval. The first billing determinant represents total flows and the second represents inadvertent flows on the transmission grid.

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The absolute value of net uninstructed deviations by Settlement interval is calculated as the absolute value of the difference between instructed energy and actual energy delivered net of changes in load. Allowing netting for changes in load permits SCs to load follow (match changes in load with changes in generation), which reduces inadvertent flows on the transmission grid.

5.3 Forward Scheduling

Forward Scheduling contains the activities associated with accepting, processing, and validating Day-Ahead and Hour-Ahead schedules. A schedule in this context is a template (import, export, load, generation, inter-SC trade, or Ancillary Service) submitted to the Scheduling Infrastructure. The costs in this sub-function relate to providing the infrastructure and to processing schedules.

All schedules are processed for each hour regardless of the time of submission. Scheduling applications run discretely for each hour and problems are resolved for each hour. The ISO re-processes each hour of a Day-Ahead schedule that rolls to the Hour-Ahead, even if it is unchanged.

The billing determinant selected by the California ISO for Forward Scheduling is the number of final Hour-Ahead schedules submitted. Only final Hour-Ahead schedules are assessed this charge. In order not to discourage SCs from modifying their Day-Ahead schedules due to better information, any changes from Day-Ahead schedules that roll over to the Hour Ahead will not be assessed an additional charge.

5.4 Congestion Management

Congestion Management contains the activities associated with mitigating scheduled transmission flows across Inter-zonal boundaries. To the extent flows increase across zonal boundaries, the California ISO incurs costs to monitor and potentially mitigate Inter-zonal congestion.

The billing determinant for Congestion Management will be assessed on net Hour-Ahead Scheduled Inter-zonal flows (load). This is the current billing determinant for the Congestion Management charge. An SC will be assessed this charge on a per MWh basis each time it schedules a flow across an Inter-zonal interface.

5.5 Market Usage

Market Usage contains the activities associated with processing Supplemental Energy and Ancillary Services, determining the Real-Time Market Clearing Price, maintaining and controlling the OASIS, monitoring market performance, and ensuring generator compliance with market protocols. In the future, activities associated with forward energy markets will be included here.

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The costs of Market Usage will be recovered from those SCs that use the Real-Time market (and the forward energy markets in the future) in a charge based on usage of these markets. The billing determinant for Market Usage will be purchases and sales of Ancillary Services, Instructed Energy and the absolute value of net portfolio deviations by Settlement interval.

This differs from the billing determinant of the current Ancillary Services/Real-Time Energy Operations Charge in that the absolute value of **net** portfolio deviations is used rather than the absolute value of **total** deviations. As was mentioned earlier, to the extent an SC accurately load follows, the California ISO need not purchase Imbalance Energy. The use of net portfolio deviations is a specific mitigation not to discourage load following.

5.6 Settlements, Metering and Client Relations

Settlements, Metering and Client Relations contains most Settlements, Billing, Metering, and Client Relations activities. Settlements, Metering and Client Relations costs are a function of the interaction of the customer and the California ISO. As many of these costs are fixed in nature, such as the requirements for settlements, billing, and processing meter data, cost recovery through a fixed charge per customer may be appropriate. There are variations in the complexity of these interactions between the California ISO and its numerous customers, which militate against recovering these costs solely through a fixed charge.

If the California ISO recovered a major portion of these costs through a single fixed charge per customer, the bill impacts would be significant. As a mitigation measure, the California ISO proposes to recover a portion of Settlements, Metering and Client Relations costs through a \$500 per month customer charge per SC ID regardless of the level of activity.

As described above, the remaining Settlements, Metering and Client Relations costs have been associated with the billing determinants of Energy and Transmission Services, Congestion Management and Market Usage. The billing determinants for these services are ISO Controlled Grid Load plus exports and net uninstructed deviations (Energy and Transmission Services), net Hour-Ahead scheduled interzonal flows (Congestion Management) and purchases and sales of Ancillary Services, instructed energy, and net uninstructed deviations (Market Usage). We made the decision not to associate costs to either Core Reliability Services or Energy and Transmission Services as these were new rates and any additional costs would increase the severity of bill impacts.

Barkovich and Yap and the ISO reviewed the occurrence of charge types in Settlement Statements over the test year period, September 2001 through August 2002. We view the occurrence of charge types in Settlement Statements as a measure of the activity flowing through Settlements. We then associated each charge type with one of the three services above. The Settlement, Metering and Client Relations costs associated with each billing determinant were proportional to the relative number of charge types associated with each service.

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Table 3 Billing Determinants by Function and Sub-Function	
Grid Reliability Services	
Core Reliability Services	534,042 MW-months (NCP demand)*
Energy and Transmission Services	
Load plus exports*	242,456,619 MWh
Absolute value of net uninstructed deviation by interval	16,403,169 MWh
Market Services	
Forward Scheduling	12,307,710 schedules
Congestion Management	87,927,387 MWh
Market Usage	45,707,872 MWh
Settlements, Metering and Client Relations	1,562 customer months
The California ISO collected billing determinants for the twelve-month period September 2001 through August 2002. This was done to facilitate the release of masked SC-specific information to participants under the conditions of providing data at least six months old. The California ISO will review more recent historical data to determine if the collected data is representative. *Not yet updated to ISO Controlled Grid Load plus exports.	

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6.0 Proposed Rates

Based on the process outlined in this paper, the resulting rates are shown in Table 4. We caution that these rates are indicative of the rates that would apply using budgeted costs for the year 2003. Therefore, these can be only illustrative of the actual rates for 2004.

Table 4 Indicative Rates by Function and Sub-Function		
	Service alone	Including Settlements, Metering and Client Relations adder
Grid Reliability Services		
Core Reliability Services	\$175.16 per MW- month of NCP demand	\$175.16 per MW- month of NCP demand
Energy and Transmission Services		
Load plus exports*	\$0.126 per MWh	\$0.234 per MWh
Absolute value of net uninstructed deviation by interval	\$0.467 per MWh	\$0.865 per MWh
Market Services		
Forward Scheduling	\$1.547 per schedule submitted	\$1.547 per schedule submitted
Congestion Management	\$0.114 per MWh	\$0.164 per MWh
Market Usage	\$0.630 per MWh	\$0.850 per MWh
Settlements, Metering and Client Relations	\$500 monthly per SC ID	\$500 monthly per SC ID
*Not yet updated to ISO Controlled Grid Load plus exports.		

The functionalization undertaken here reflects an effort to maximize the cost basis of the California ISO's rates. In order to implement this functionalization, it is anticipated that there will be bill impacts that require mitigation. These bill impacts will be studied in depth along with the bill impacts of other proposals. Rates will be adjusted in order to reduce the level of bill impacts to a manageable and reasonable level while preserving the cost basis of the rates to the greatest extent possible.

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7.0 Remaining Issues

As in any undertaking of this magnitude, there are a number of remaining issues that the California ISO and participants must consider. These are:

1. Discussion of commonalities among the California ISO, MID and SCE proposals and the potential for consensus.
2. Potential increased use of direct assignments of indirect expenditures
One participant has requested that the CAISO make an effort to assign more directly the costs that have been assigned indirectly in the past. For this proposal, we have directly assigned costs to the extent possible. There is still some work in this area.
3. Continued analysis of bill impacts
4. Stability of billing determinants through the first part of 2003
We will be providing more recent history on the billing determinants used in all proposals. This will be done to show if there is evidence of a trend or a change in trend since August 2002.

Appendix A
Functionalization of Activity Groupings for ISO Rate Structure (DRAFT)

Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
Grid Reliability Services	Core Reliability Services (base level) Energy and Transmission Services (scalable portion)	Real-Time Grid Operations - RT Grid Resource Coordination - Gen Dispatchers - RT Intertie Scheduling - Trans Dispatchers	Ancillary Services management: - Dispatch of energy associated with Ancillary Services, including: - Regulation - Spin - Non-spin - Replacement reserve - Black start Monitoring of system conditions and dispatching to maintain reliability: - Load and resource balancing - Transmission line/path congestion management - Voltage control - Frequency control - System emergency management - Power flow studies and security analyses Determination of resource adequacy in real time Coordinating Western Interconnection reliability with all WECC Reliability Coordinators Integration and communication with other Control Areas: - Interconnected switching operations for planned and unplanned outages - Generation and transmission equipment outage coordination Interchange scheduling ETC scheduling and administration EMS and Telemetry management	1544 – Real Time Scheduling 1564 – Operations Scheduling 1546 – Security Coordination 1545 – Grid Operations 1566 – Regional Coordination 1461 – Control Systems 1752 – Manager of Markets (portion) 1462 – Field Data Acquisition (portion)	See Cost Allocation Matrix detail on assignment of system applications

Appendix A **Functionalization of Activity Groupings for ISO Rate Structure (DRAFT)**

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Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
Grid Reliability Services	Core Reliability Services (base level) Energy and Transmission Services (scalable portion)	Interchange Pre-Scheduling WECC Requirements	Day-ahead/Hour-ahead intertie scheduling - ETAG (NERC-required electronic schedule tagging) - Existing Transmission Contracts Calculator (ETCC) and scheduling - New Firm Uses (NFU) scheduling Reconciliation of schedules and interchange after-the-fact NERC/WECC/CAISO Tariff required reporting Weekly: - Inadvertent Interchange report - NERC reports (Inadvertent Interchange, ETAG) - WECC "donut" report Monthly: - WECC Unscheduled Flow curtailment report Quarterly: - Quarterly California Energy Commission 1305 report Annually: - SDG&E DOE report - FERC 714 report - Report of Economic Operation	1565 – Pre-scheduling and Support	
	Core Reliability Services (base level) Energy and Transmission Services (scalable portion)	Outage Coordination	Pre-planning of and preparation for generation and transmission outages Generation and transmission equipment outage tracking and data/record keeping On-site generation outage monitoring (SB-39 compliance) Outage reporting (web site updates and regulatory agency reporting) Supply of Generation and Transmission data for OASIS postings	1542 Outage Coordination	

Appendix A Functionalization of Activity Groupings for ISO Rate Structure (DRAFT)

Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
Grid Reliability Services	Core Reliability Services (base level) Energy and Transmission Services (scalable portion)	Operations Engineering, Maintenance, and Support	Transmission Maintenance: - Develop, monitor and enforce of transmission maintenance standards - Manage and oversee new generation interconnections, major capacity additions or upgrades and supporting Transmission Planning in project tracking. - Manage, analyze, prepare reports on system availability, reliability, and outage records. - Manage, audit, investigate, approving Transmission Maintenance Practices. - Manage, oversee, and approve the equipment ratings. Operations Engineering: - Perform seasonal, annual, and, as necessary special analysis of transmission system performance and ratings. - Review, approve and provide specification on daily system configurations, emergency conditions, clearances and operational conditions. - Develop, prepare and update operating procedures. - Perform operational studies and system security analyses Operations Support: Manage the development, preparation and revision of all ISO Operating Procedures: - Transmission grid - Market Operations - Generation - Emergency - Perform generating unit ancillary service certification and P-MAX testing - Manage UDC and Inter-Control Area Operating agreements - Manage dynamic energy scheduling agreements and interfaces - Manage required WECC Reliability Management System (RMS) and NERC.	1558 – Transmission Maintenance 1561 – Operations Engineering, South 1562 – Operations Engineering, North 1554 – Special Projects Engineering 1549 – Operations Training Group 1555 – Operations Support Group 1559 – Operations Application Support 1563 – Coordinated Operations	
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Appendix A **Functionalization of Activity Groupings for ISO Rate Structure (DRAFT)**

Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
Grid Reliability Services	Core Reliability Services (base level) Energy and Transmission Services (scalable portion)	Loads & Resources Grid Planning Operations R&D	Transmission Planning: - Perform system transmission planning to ensure overall reliability - Perform reserve requirement studies - Perform Long-term (monthly, annual and longer) load forecasting - Determine long term <i>transmission</i> resource adequacy Regional Coordination: - Coordinate participation in NERC, WECC, NAEBS, ESC, and OSC - Monitor and participate in resolving seams issues in the Western Interconnection - Provide Control Area and interconnection mapping services to real time operations. Determine long-term <i>generation</i> resource adequacy: - Manage, develop, prepare, publish and participate in seasonal system load and generation assessments. - Participate, guide, influence, and maintain records on environmentally constrained generation units. - Determine dual fuel generator requirements Determine Reliability Must-Run (“RMR”) contract requirements Review Participating Transmission Owners (“PTOs”) Bulk Power Program and new generator or load interconnection studies	1521 – Grid Planning 1543 – Loads and Resources 1566 – Regional Coordination	
	Core Reliability Services (base level)	Reliability Contract Administration	Administration of RMR settlements Validation of Summer Reliability Generation invoices Development and implementation of Tariff modifications Maintenance of agreements with existing and new clients Meeting regulatory directives related to contract activities Non-vendor contract administration	1723 Tariff and Contracts Implementation 1731 Contracts and Special Projects (portion)	

Appendix A
Functionalization of Activity Groupings for ISO Rate Structure (DRAFT)

Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
Grid Reliability Services	Energy and Transmission Services (scalable portion)	Market Monitoring and Compliance	Evaluation of transmission capacity expansion Review and recommend changes to ISO rules and protocols Monitor and measure operational performance consistent with contractual commitments and Tariff requirements Ensure generator compliance with dispatch instructions and must offer requirements Administer ISO Oversight and Investigations Review	1641 – Market Analysis (portion) 1642 – Market Surveillance Committee (portion) 1661 – Compliance (portion) 1662 – Data Quality Group (portion)	
Market Services	Forward Scheduling	HA Grid Resources Coordination DA Grid Resources Coordination Markets & Scheduling Group (portion) Market Operations (portion) Market Engineering (portion) Business Solutions (portion) Market Integration (portion) Congestion (portion) ETCs	Manage transmission and generation schedules: - Day and Hour-Ahead schedules (including Participating Intermittent Resources) - Determine schedule feasibility	1752 – Manager of Markets (portion) 1753 – Market Application and Testing (portion) 1755 – Business Solutions (portion) 1757 – Market Integration (portion)	
Market Services	Congestion Management	Congestion (portion)	Manage inter-zonal congestion	1752 – Manager of Markets (portion) 1753 – Market Application and Testing (portion) 1755 – Business Solutions (portion) 1757 – Market Integration (portion) 1756 – Market Quality (portion)	

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Appendix A **Functionalization of Activity Groupings for ISO Rate Structure (DRAFT)**

Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
Market Services	Congestion Management	Marketing monitoring	Monitoring and reporting on congestion management market performance Investigating and reporting on potential gaming and market power abuses (congestion)	1641 – Market Analysis (portion) 1642 – Market Surveillance Committee (portion) 1661 – Compliance (portion) 1662 – Data Quality Group (portion)	
Market Services	Market Usage	Market Operations Manager of Markets Market Quality (portion) Market Eng (portion) Business Solution (portion) Market Integration (portion) Markets & Scheduling Group (portion) Market Monitoring & Compliance FTR Auctions	Perform weekly, daily and hourly load forecasting Operate A/S and Real-Time markets Determine market clearing prices (A/S and Energy) Mitigate bids (real time and forward) Maintenance of market information postings (transmission/market OASIS) Operate unit commitment service under SMD Mitigate market power in Day-Ahead, Hour-Ahead and Real Time markets Develop and manage demand response participation Administer FTRs: • Perform FTR auctions (Primary) • Coordinate FTR bilateral trading (Secondary) • Calculate and determine feasibility of FTR capacity	1752 – Manager of Markets 1753 – Market Application and Testing 1757 – Market Integration 1756 – Market Quality (portion)	
Market Services	Market Usage	Marketing monitoring and compliance	Monitor and report on market performance Investigate and report on potential gaming and market abuses Perform special studies on market efficiency, bidding behavior Develop new market rules or changes to market rules in response to market behavior Prepare and provide reports to regulatory authorities Implement and calculate penalties and sanctions for noncompliance	1641 – Market Analysis (portion) 1642 – Market Surveillance Committee (portion) 1661 – Compliance (portion) 1662 – Data Quality Group (portion)	

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Appendix A **Functionalization of Activity Groupings for ISO Rate Structure (DRAFT)**

Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
Settlements, Metering and Client Relations		Settlements, Billing, Credit Administration and Metering	Determine charges associated with: • Transmission services • Day-Ahead schedules and markets (A/S and Energy) • Hour-Ahead schedules and markets (A/S and Energy) • Real time balancing energy market • Congestion management • Administrative charges, including the Grid Management Charge Manage settlement data Manage ETC manual settlements Prepare market and GMC invoices Prepare special invoices for FERC fees, interest, etc. Perform settlement statement reruns Market/settlements design and settlements training Dispute resolution, GFN, arbitration and monitoring Credit and collateral management • Manage collections and payments • SC financial security analysis Determination of losses and allocation Metering and data management • Collect and validate data from ISO polled meters • Repository of data polled from ISO polled meters and data submitted by SCs • Responsible for site inspection of metering sites • Responsible for setting up RIG data bases and submitting data into EMS • Push data to Settlement databases Manage Participating Intermittent Resources settlements	1722 – Application Support 1723 – Tariff and contract implementation 1724 – BBS-PSS 1725 – BBS-FSS 1462 – Field Data Acquisition (portion) 1321 - Accounting (portion) 1756 – Market Quality (portion)	

Appendix A
Functionalization of Activity Groupings for ISO Rate Structure (DRAFT)

Function	Sub-Function	Direct Personnel	Activities within proposed Grouping	Indicative Cost Centers (There is some overlap among cost centers)	Applications
Settlements, Metering and Client Relations		Account Management Services and Training	Provide ISO Tariff, Systems, Market and Settlements guidance to market participants Communicate scheduled events to market participants Communicate Market information Develop training curriculum Provide training to Market Participants (Settlements, System Infrastructure, Market Design) Facilitate stakeholder process Facilitate resolution of Market Participant issues	1741 – Client Relations	
Settlements, Metering and Client Relations		ISO contract administration	Administer ISO contracts (non-vendor, e.g., RMR, PTO, MSS) Negotiate, manage, litigate contracts	1731 – Contracts and Special Projects (portion)	
		Administrative and General (not directly assigned elsewhere)	CEO Finance and Accounting Legal HR Regulatory policy and affairs Information services Strategic development Communications	1111 – CEO 1651 – Board of Governors 1241 – MD02 (currently) 1300 – Finance indirects 1400 – Information Services indirects 1600 – Legal and Regulatory indirects 1700 – Market Services indirects 1800 – Corporate and Strategic Development indirects	
All	All	Startup costs	Recover costs associated with Startup		

Appendix B

Comparison of California ISO Rate Structure Proposal to Rate Structures of other ISO/RTOs

Reliability Function			Billing Determinant
ISO/RTO	Name	Description	
ISO-NE	Reliability Administration (Schedule 3)	Administer reliability markets, including Operating Reserve Markets, AGC/Regulation markets, ICAP settlement. Examples of functions performed: gen. dispatch associated with reliability markets; reliability markets accounting; billing preparation; generation emissions analysis; risk profile updates; resource adequacy reviews; regional reports/load forecasts/profiles (CELT, EIA, NERC); support of power supply, environmental, market reliability planning activities; market power monitoring, mitigation and assessment of reliability markets; formulation of additional reliability market rules.	Non-coincident kW-months
NYISO	NA bundled rate		
PJM	Control Area (schedule 9-1)	Control Area Services includes costs of all PJM activities associated with preserving the reliability of the PJM and PJM West control areas and administering point to point transmission service and network integration transmission service.	MWhs of point to point and network integration services flows
	Regulation and Frequency Response (Schedule 9-5)	Regulation and Frequency Response Administration Service includes the costs associated with administering the provision of Regulation and Frequency Response Service under Schedule 3 of the Tariff. PJM provides this service to Load Serving Entities and to generators that provide regulation in accordance with Schedule 3.	MWhs of PJM regulation plus scheduled (including self-scheduled) regulation
	Capacity and Resource Obligation Management (Schedule 9-7)	Capacity Resource and Obligation Management Service includes the costs associated with (i) assuring that customers have arranged for sufficient generating capacity to meet their installed capacity obligations under the RAA and RAA-West; (ii) processing Network Integration Transmission Service; and (iii) administering the capacity credit market in the PJM Control Area and available capacity credit market in the PJM West Region	Allocated to East/West by relative East/West non-coincident peak assessed on MW-days
ERCOT	Bundled rate		
Ontario IMO	Bundled rate		
Midwest ISO	No separate Reliability Function		
CAISO (Proposed)	Core Reliability Services	In this sub-function, the ISO provides a stable grid and meets regional and national regulatory requirements, such as NERC and WECC reliability criteria and some FERC requirements (e.g., a basic level of transmission planning). All necessary activities attributable to Control Area operation including the capability of handling a system that is as geographically dispersed as the present system but without features that are scalable (i.e., that vary according to use or size of flow) are contained in this function.	Non-coincident peak demand including behind the meter non-coincident peak demand QF NCP adjusted for diversity(MW)
	Energy and Transmission Services	The ISO provides more than the basic level of the safe, reliable operation of a Control Area surrounded by other control areas assuming everyday (normal and extraordinary) operational requirements in which outages and other disruptions occur frequently and consistently. This is the scalable portion of Reliability Services that occurs due to the everyday occurrence of system activity.	Net control area load (MWh)

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Market Services Function			Billing Determinant
ISO/RTO	Name	Description	
ISO-NE	Scheduling, System Control and Dispatch (Schedule 1)	Includes scheduling service, provision of A/S. Processing requests for transmission service, coordination of transmission system operation, billing associated with transmission service, transmission system planning, administrative support for these.	Monthly Network load in kW plus highest amount of reserved capacity of point to point transmission service plus the highest amount of unauthorized use
	Energy Administration (Schedule 2)	Includes dispatch service. Administer energy market and facilitate interchange transactions, bilateral transactions and generator bids. In summary: Generator dispatch, energy accounting, loss determination and allocation, billing preparation, administration of imbalance energy service, market power monitoring & mitigation, sanction activities, energy market assessments & reports, formulation of market rules, administer FTRs, ARRs.	15% to Transaction units – bilateral contract block hours plus generator block hours plus “net deviation” block hours
NYISO	NA bundled rate		85 % to Load and injections MWh
PJM	Market Support (Schedule 9-4)	Market Support Service includes costs associated with supporting the operation of the PJM Interchange Energy Market and related functions, as described in Schedule 1 of the Operating Agreement and the Appendix to Attachment K to the Tariff, including, market modeling and scheduling functions, locational marginal pricing support, market settlements and billing, and market monitoring.	Generation and Load MWh
	Fixed Transmission Rights (Schedule 9-3)	Fixed Transmission Rights Administration Service includes the costs associated with administering the Fixed Transmission Rights (“FTRs”) provided for under Attachment K to this Tariff, including, coordination of FTR bilateral trading, administration of FTR auctions, support of PJM's on-line, Internet-based eFTR tool, and analyses to determine what total combination of FTRs can be outstanding and accommodated by the PJM system at a given time	FTR MW per hour summed over hours
ERCOT			
Ontario IMO			
Midwest ISO			

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CAISO (Proposed)	Market Scheduling	The ISO provides energy and Ancillary Services scheduling in forward markets and processing of accepted Ancillary Services bids. In this context, a schedule is represented by a scheduling template (import, export, load, generation, inter-SC trade and Ancillary Services, including self-provided AS) submitted to the ISO Scheduling Infrastructure.	Per schedule, import, export, load, generation, inter-SC trade and AS, submitted
	Congestion Management	The ISO provides management and operation of inter-zonal congestion markets, using adjustment bids, taking Firm Transmission Rights and Existing Transmission Contracts into account, and determining the price for mitigating congestion for flows on congested paths.	MW's of Scheduled Interzonal flows (load)
	Market Usage	The ISO provides access to forward and Real-Time energy and Ancillary Services markets.	MW's purchases and sales of Ancillary Services, instructed energy and the absolute value of net uninstructed deviations. No assessment on self-provided Ancillary Services

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Annual Fee			
	Name	Description	Billing Determinant
ISO-NE	Annual fee, no separate CS function	\$5,000/year	
NYISO	Annual fee, no separate CS function	Small Consumers \$100 – 0 to 499 MWh/year \$500 – 500 to 1999 MWh/year \$1,000 – greater than 2000 MWh/year \$5,000 – all other companies \$5,000/year	
PJM	Annual fee, no separate CS function	\$5,000/year	
ERCOT	Annual fee, no separate CS function	\$2,000 – full members \$500 – adjunct members	
Ontario IMO	Annual fee, no separate CS function	\$0 – 0 to 99 MWh/year \$1,000 – 100 to 2,999 MWh/year \$8,000 – greater than 3,000 MWh/year < none	
MidWest ISO	Annual fee, no separate CS function	none	
CAISO (Proposed)	Settlements, Metering and Client Relations	Monthly fee of \$500 per SC ID	

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Startup Costs			
	Name	Description	Billing Determinant
ISO-NE	No separate startup cost component		
NYISO	Separate collection of Start-up costs	Separate collection and amortization of start-up costs. Currently the annual amortization is \$13.15 million. The rate for March is approximately \$0.47 per MWh.	MWh
PJM	No separate startup cost component		
ERCOT	No separate startup cost component		
Midwest ISO			
CAISO (Proposed)	Start-up Costs	Recovery of bond financed capital expenditures from 1997 through 2000. The annual debt service cost is approximately \$43 million with an additional \$11 million collected in interest coverage. The bonds are fully amortized in 2009.	Assigned to other rate components

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**Appendix C
California ISO**

Functional Association of Charge Types

Date: June 25, 2003

Released: June 25, 2003

Disclaimer Regarding the Attached Data

purpose of furthering discussion and research in the ISO's '2004 GMC Rate Structure Project'. The data, in the form attached, is provided in response to Stakeholders' requests and as such does not necessarily indicate the ISO's concurrence in, or support for, its usefulness in developing a rate methodology. No implications may be drawn regarding the ISO's position on any subject in the Project from either the inclusion or exclusion of any specific data. The ISO does not warrant the completeness or accuracy of the data.

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Assessment of Rate Impact with Functional Association of Customer Service Revenues Based on Charge Type Analysis

This data is subject always to the Disclaimer issued by the ISO at the time of its distribution.

Existing Rates		Control Area Services		Congestion Management		Ancillary Services and Real Time Energy	
% of Total		58%		12%		30%	
Revenue Requirement	\$	137,856,869	\$	27,400,520	\$	72,342,981	
9/2001-8/2002 Volume		242,456,619		87,927,387		73,374,094	
Rate / MWh	\$	0.569	\$	0.312	\$	0.986	
Description of Billing Determinant		Gross Control Area Load & Exports		Net interzonal Scheduled load		Purchases & sales of A/S & RT Energy	
New Rate Design		Core Reliability Services		Energy & Transmission Services Load		Energy & Transmission Services Deviation	
% of Total		39%		13%		3%	
Revenue Requirement	\$	93,544,836	\$	30,670,132	\$	7,667,533	\$
9/2001-8/2002 Volume		534,042		242,456,619		16,403,169	
Rate / MW or MWh	\$	175.16	\$	0.13	\$	0.47	\$
Calculation of Rates After Customer Service Revenues Are Reassigned							
Cust Add Rate Opt 1 /1	\$		\$	0.11	\$	0.40	\$
Total Rate Opt 1	\$	175.16	\$	0.23	\$	0.87	\$
Description of Billing Determinant		Non-coincident peak demand/MW		Net Control Area Load plus exports in MWh. Not yet updated to reflect Controlled Grid Load		Absolute value of net uninstructed deviations by settlement interval in MWh	
						Purchases and sales of Ancillary Services, changes to DA schedules instructed energy and absolute value of net uninstructed deviations by settlement interval MWh	
				</			

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Charge Type ID	Charge Description	Billable Quantity	Price	Count of Charge Types and Functional Association on a Count Basis No of Trans w/Chg Type	Percentage	GRS Count	CONG Count	Sched Count	Market Usage Count
1	Day Ahead Spinning Reserve due SC	Spinning Reserve accepted bid quantity [per SC, per location]	Price = Max (Bid price, DA Zonal Spinning Reserve MCP)	1,917	0.9%	1,438			479
2	Day Ahead Non-Spinning Reserve due SC	Non-Spinning Reserve Accepted Bid Quantity [per SC, per location]	Price = Max (Bid price, DA Zonal Non Spinning Reserve MCP)	1,452	0.7%	1,089			363
4	Day Ahead Replacement Reserve due SC	Replacement Reserve Accepted Bid Quantity [per SC, per location]	Price = Max (Bid price, DA Zonal Replacement Reserve MCP)	506	0.2%	380			127
5	Day Ahead Regulation Up due SC	Day Ahead Regulation Up Accepted Bid Quantity [per SC, per location]	Price = Max (Bid price, DA Zonal Regulation Up MCP)	1,818	0.9%	1,364			455
6	Day Ahead Regulation Down due SC	Day Ahead Regulation Down Accepted Bid Quantity [per SC, per location]	Price = Max (Bid price, DA Zonal Regulation Down MCP)	1,931	0.9%	1,448			483
7	Demand Relief Monthly Capacity Payment	Committed Capacity for the participation in the Demand Relief Program [per SC, per location]	Fixed Price per participant's bid. Includes a Non-Performance Payment Offset for monthly compliance less than 90%	6	0.0%	5			2
24	Dispatched Replacement Reserve (Bid-In) Capacity Withhold	Amount of "bid-in" Replacement Reserve capacity that has been dispatched by ISO [per SC, per location]	Weighted average Replacement Reserve price (GRSPP) received by the resource in that hour for its "bid-in" Capacity	189	0.1%	142			47
51	Hour Ahead Spinning Reserve due SC	Hour-Ahead additional Spinning Reserve accepted bid quantity [per SC, per location]	Price = Max (Bid price, HA Zonal Spinning Reserve MCP)	2,336	1.1%	1,752			584
52	Hour Ahead Non-Spinning Reserve due SC	Hour-Ahead additional Non-Spinning Reserve accepted bid quantity [per SC, per location]	Price = Max (Bid price, HA Zonal Non Spinning Reserve MCP)	1,938	0.9%	1,454			485
54	Hour Ahead Replacement Reserve due SC	Hour-Ahead additional Replacement Reserve accepted Bid Quantity [per SC, per location]	Price = Max (Bid price, HA Zonal Replacement Reserve MCP)	918	0.4%	689			230
55	Hour Ahead Regulation Up due SC	Hour Ahead Regulation Up Accepted Bid Quantity [per SC, per location]	Price = Max (Bid price, HA Zonal Regulation Up MCP)	1,958	0.9%	1,469			490
56	Hour Ahead Regulation Down due SC	Hour Ahead Regulation Down Accepted Bid Quantity [per SC, per location]	Price = Max (Bid price, HA Zonal Regulation Down MCP)	1,981	0.9%	1,486			495
61	Hour Ahead RMR Preemption of Spinning Reserve (HA Price)	Amount of Spinning Reserve Pre-empted before close of HA Market [per SC, per location]	Zonal Spinning Reserve Capacity Hour Ahead Market Clearing Price for Trading Interval	1	0.0%	1			
65	Hour Ahead RMR Preemption of Regulation Up (HA Price)	Amount of Regulation Up Pre-empted before close of HA Market [per SC, per location]	Zonal Regulation Up Capacity Hour Ahead Market Clearing Price for Trading Interval	1	0.0%	1			
66	Hour Ahead RMR Preemption of Regulation Down (HA Price)	Amount of Regulation Down Pre-empted before close of HA Market [per SC, per location]	Zonal Regulation Down Capacity Hour Ahead Market Clearing Price for Trading Interval	1	0.0%	1			
71	Real Time RMR Preemption of Spinning Reserve (DA Price)	Amount of Spinning Reserve Pre-empted after close of Hour Ahead Market at Day Ahead Price [per SC, per location]	Zonal Spinning Reserve Capacity Day Ahead Market Clearing Price for Trading Interval	26	0.0%	26			
72	Real Time RMR Preemption of Non-Spinning Reserve (DA Price)	Amount of Non-Spinning Reserve Pre-empted after close of Hour Ahead Market at Day Ahead Price [per SC, per location]	Zonal Non-Spinning Reserve Capacity Day Ahead Market Clearing Price for Trading Interval	61	0.0%	61			
81	Real Time RMR Preemption of Spinning Reserve (HA Price)	Amount of Spinning Reserve Pre-empted after close of Hour Ahead Market at Hour Ahead Price [per SC, per location]	Zonal Spinning Reserve Capacity Hour Ahead Market Clearing Price for Trading Interval	2	0.0%	2			
82	Real Time RMR Preemption of Non-Spinning Reserve (HA Price)	Amount of Non-Spinning Reserve Pre-empted after close of Hour Ahead Market at Hour Ahead Price [per SC, per location]	Zonal Non-Spinning Reserve Capacity Hour Ahead Market Clearing Price for Trading Interval	3	0.0%	3			
84	Real Time RMR Preemption of Replacement Reserve (HA Price)	Amount of Replacement Reserve Pre-empted after close of Hour Ahead Market at Hour Ahead Price [per SC, per location]	Zonal Replacement Reserve Capacity Hour Ahead Market Clearing Price for Trading Interval	2	0.0%	2			
111	Spinning Reserve due ISO	Net Reserve Obligation [per SC, per zone]	Price = (DAQDAP + HACTHAP) / (DAQ + HAQ) where DAQ = DA procurement target in DA region HAQ = Incremental HA procurement target in the zones that make up the DA region DAP = Average procurement price in the DA region HAP = Average procurement	11,629	5.5%	8,722			2,907

Association of Settlement System with Functional Categories

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Charge Type ID	Charge Description	Bilable Quantity	Price	Count of Charge Types and Functional Association on a Count Basis				
				No of Trans w/Chg Type	Percentage	GRS Count	CONG Count	Sched Count Market Usage Count
112	Non-Spinning Reserve due ISO	Net Reserve Obligation [per SC, per zone]	Price = (DAQ*DAP + HAQ*HAP) / (DAQ + HAQ) where DAQ = DA procurement target in DA region HAQ = Incremental HA procurement target in the zones that make up the DA region DAP = Average procurement price in the DA region HAP = Average procurement price in the DA region	11,497	5.5%	8,623		2,874
114	Replacement Reserve due ISO	Net Reserve Obligation [per SC, per zone]	Price = (DAQ*DAP + HAQ*HAP - SRRWC) / (DAQ + HAQ) where DAQ = DA procurement target in DA region HAQ = Incremental HA procurement target in the zones that make up the DA region DAP = Average procurement price in the DA region HAP = Average procurement price in the DA region	9,796	4.7%	7,347		2,449
115	Regulation Up Due ISO	Net Reserve Obligation [per SC, per zone]	Price = (DAQ*DAP + HAQ*HAP) / (DAQ + HAQ) where DAQ = DA procurement target in DA region HAQ = Incremental HA procurement target in the zones that make up the DA region DAP = Average procurement price in the DA region HAP = Average procurement price in the DA region	11,306	5.4%	8,480		2,827
116	Regulation Down Due ISO	Net Reserve Obligation [per SC, per zone]	Price = (DAQ*DAP + HAQ*HAP) / (DAQ + HAQ) where DAQ = DA procurement target in DA region HAQ = Incremental HA procurement target in the zones that make up the DA region DAP = Average procurement price in the DA region HAP = Average procurement price in the DA region	11,342	5.4%	8,507		2,836
117	Demand Relief Monthly Capacity Charge	SC's Metered Demand excluding any non-PTO load under Existing Contracts in the Control Area [Per SC]	Total capacity payments for DRP / Total Metered Demand in Control Area	172	0.1%			172
124	Dispatched Replacement Reserve (Self-Provided) Capacity Withhold	Amount of Excess Self-Provided Replacement Reserve capacity that has been dispatched by ISO [per SC, per region]	User Rate for Replacement Reserve in the Region (i.e. price for CT 114) Amount Due is calculated by prorating the Bilable Quantity between DA and HA markets and multiplying with the corresponding MCP for Spin Reserve.	6	0.0%	6		
141	No Pay Charge - Spinning Reserve	No Pay Spin Qty = max(NPSR(1):h,k, NPSR(2):h,k, NPSR(3):h,k) [per SC, Per Location]	Price = Amount Due / Bilable Quantity Amount Due is calculated by prorating the Bilable Quantity between DA and HA markets and multiplying with the corresponding MCP for Non Spin Reserve.	1,384	0.7%	1,384		
142	No Pay Charge - Non Spinning Reserve	No Pay Non Spin Qty = max(NPNS(1):h,k, NPNS(2):h,k, NPNS(3):h,k) [per SC, Per Location]	Price = Amount Due / Bilable Quantity Amount Due is calculated by prorating the Bilable Quantity between DA and HA markets and multiplying with the corresponding MCP for Replacement Reserve.	690	0.3%	690		
144	No Pay Charge - Replacement Reserve	No Pay Repl. Reserve Qty = max(NPRR(1):h,k, NPRR(2):h,k, NPRR(3):h,k) [per SC, Per Location]	Price = Amount Due / Bilable Quantity Pseudo Price = Settlement Amount / Bilable Quantity. Settlement amount is calculated by prorating the bilable quantity between DA and HA markets and multiplying with the corresponding MCP for the Regulation Up.	153	0.1%	153		
145	Non Compliance Charge for Regulation Up	Unavailable A/S Capacity [per SC, per location]		1,322	0.6%	1,322		

Association of Settlement System with Functional Categories

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Charge Type ID	Charge Description	Billable Quantity	Price	No of Trans w/Chg Type	Percentage	GRS Count	CONG Count	Sched Count	Market Usage Count
146	Non Compliance Charge for Regulation Down	Unavailable AIS Capacity [per SC, per location]	Pseudo Price = Settlement Amount / Billable Quantity. Settlement amount is calculated by prorating the billable quantity between DA and HA markets and multiplying with the corresponding MCP for the Regulation Down.	1,403	0.7%	1,403			
203	Day-Ahead Inter-Zonal Congestion Settlement	SC's Day-Ahead net New Firm Use (NFIU) import into a Zone [per SC, per Zone]	Price = Day-Ahead Zonal MCP (Reference Price, I)	6,932	3.3%		6,932		
204	Day-Ahead Inter-Zonal Congestion Refund due TO	SC's (TO or FTR Owner) Percentage Entitlement on Branch Group * Branch Group NFIU loading [per SC, per Branch Group]	Price = Day-Ahead Congestion Price of Branch Group (Shadow Price, m)	2,608	1.2%		2,608		
253	Hour-Ahead Inter-Zonal Congestion	SC's Hour-Ahead additional New Firm Use (NFIU) import into a Zone [per SC, per Zone]	Price = Hour-Ahead Zonal MCP (Reference Price, I)	5,739	2.7%		5,739		
254	Hour-Ahead Inter-Zonal Congestion Refund due TO	SC's (TO or FTR Owner) Percentage Entitlement on Branch Group * Increase in Branch Group NFIU loading from Day-Ahead to Hour-Ahead [per SC, per Branch Group]	Price = Hour-Ahead Congestion Price of Branch Group location (Shadow Price, m)	2,020	1.0%		2,020		
255	Hour-Ahead Inter-Zonal Congestion Debit to TOs	SC's (TO or FTR Owner) Percentage Entitlement on Branch Group * Decrease in Branch Group NFIU loading from Day-Ahead to Hour-Ahead [per SC, per Branch Group]	Price = Day-Ahead Congestion Price of Branch Group (Shadow Price, m)	493	0.2%		493		
256	Hour-Ahead Inter-Zonal Congestion Debit to SCs	SC's Day-Ahead Path Utilization in the Congested Direction [per SC, per Branch Group]	Price = [(DA Path Loading - HA Path Loading) * HA Congestion Price - TO Debit Amount for Path] / Total DA Path Flow in the Congested Direction	1,203	0.6%		1,203		
302	Supplemental Reactive Power Due SC	Total payment to resources providing Supplemental Reactive Power in a Participating Transmission Owner's area [per Transmission Owner]	N/A; Set to 1	12	0.0%	12			
372	High Voltage Access Charge due ISO	UDCs, MSS, SCs Metered Loads adjusted for ETC exemptions, Transmission Charge, Proportionality, and Burden Capex [per SC, per TAC Area]	High Voltage Transmission Access Charge Rate for the TAC Area	84	0.0%	84			
374	High Voltage Access Revenue due PTO	Please refer to ISO Tariff 7.1.3 and Section 10 of Appendix F Schedule 3		60	0.0%	60			
382	High Voltage Wheeling Charge due ISO	Real time gross export excluding amounts exempted due to ETCs [per SC, per location]	Please refer to ISO Tariff 7.1.3 and Section 10 of Appendix F Schedule 3 High Voltage Wheeling Access Rate at exit location (= TAC Area rate, or weighted TAC Area rate if there are multiple owners from different TAC areas)	408	0.2%	408			
383	Low Voltage Wheeling Charge due ISO	Real time gross export excluding amounts exempted due to ETCs [per SC, per location]	Low Voltage Wheeling Access Rate at exit location (= Owner's Low Voltage Access rate, or weighted Low Voltage Access rate if there are multiple owners)	69	0.0%	69			
384	High Voltage Wheeling Revenue due TO	Real time gross export excluding amounts exempted due to ETCs * TO allocation percentage [per TO, per location]	High Voltage Wheeling Access Rate at exit location (= TAC Area rate, or weighted TAC Area rate if there are multiple owners from different TAC areas)	65	0.0%	65			
385	Low Voltage Wheeling Revenue due TO	Real time gross export excluding amounts exempted due to ETCs * TO allocation percentage [per TO, per location]	Low Voltage Wheeling Access Rate at exit location (= Owner's Low Voltage Access rate, or weighted Low Voltage Access rate if there are multiple owners)	35	0.0%	35			
401	Instructed Energy	Energy delivered in excess of schedule in accordance with ISO instructions [per SC, per Location/interchange]. Instructed energy is settled in the following sequence: 1) Ramping Energy; 2) Negative Out of stack and Supplemental Energy; 3) Out of stack En	-1 * Amount Due = (Ramping Energy * 0) + (+ve Suppl. Imbal. Energy * INC MCP) + (-ve Suppl. Imbal. Energy * DEC MCP) + (Imbal. Energy from Spin + Imbal. Energy from Non Spin + Imbal. Energy from RR) * INC MCP) + (+ve Out of stack Energy * min(DEC MCP, Price = Amount Due / Billable Qty	4,553	2.2%	3,415			1,138
406	SC Unaccounted for Energy (UnElogical)	UnE Quantity [per SC, per Zone]	Price = DEC MCP if Billable Quantity > 0 INC MCP if Billable Quantity < 0	13,580	6.5%	10,185			3,395
407	Uninstructed Energy	Sum of Uninstructed Energy [per SC, per Congestion Region]	Price = Withhold Amount / Billable Quantity Withhold Amount is first taken from the Instructed Energy payment (at the Average Price for the instructed energy in the trading interval) and then from the Uninstructed Energy (at the Incremental MCP of the in	17,230	8.2%	12,923			4,308
410	Unscheduled RMR Energy	Energy generated in excess of scheduled energy, up to RMR dispatched amount [per SC, per location]	Amount Due = -1 * SC(Min(AIE/h.k.n, BE/h.k.n)*EP/h.k.o)	211	0.1%	159			53
481	Excess Cost for Instructed Energy	Energy delivered [per SC, per Location/interchange] having a price segment > MCP+	Price = -1 * Amount Due / Billable Quantity	309	0.1%	232			77
487	Allocation of Excess Cost for Instructed Energy	SC's Net Negative Uninstructed Energy in the Control Area [per SC]	Price = UEPh.k (see formulation below)	4,638	2.2%	3,719			1,160
521	GMC-Control Area Services	SC metered Gross Load and real time gross export [per SC]	Control Area Service Charge Price	586	0.3%	586			

Association of Settlement System with Functional Categories

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Charge Type ID	Charge Description	Billable Quantity	Price	No of Trans w/Chg Type	Percentage	GRS Count	CONG Count	Sched Count	Market Usage Count
522	GMC-Congestion Management	Aggregate of the absolute values of the hourly net scheduled inter-zonal New Firm Use flows [per SC]	Inter-Zonal Scheduling Charge Price	580	0.3%		580		
523	Market Operations Grid Management Charge	Aggregate of the absolute values of the hourly purchases/sales of Ancillary Services and 10-Minute Imbalance Energy [per SC]	Market Operations Charge Price	222	0.1%				222
524	GMC-AIS and RT Energy Operations	Aggregate of the absolute values of the following: hourly purchases/sales of Ancillary Services, 50% of Effective Self Provision, and 10-Minute Imbalance Energy [per SC]	Rate of AIS and Real Time Energy Operations Charge	468	0.2%				468
550	FERC fee	SC's Metered Demands in the Control Area [per SC]	0.021MMWh	671	0.3%	671			
591	Emissions Cost Recovery	SC in-state metered Load (consists of metered load within ISO Control Area and real time gross export to other in-state Control Areas) [per SC]	Emissions Cost Recovery Rate (Published by ISO)	480	0.2%		480		
592	Start-Up Cost Recovery	SC in-state metered Load (consists of metered load within ISO Control Area and real time gross export to other in-state Control Areas) [per SC]	Start-Up Cost Recovery Rate (Published by ISO)	476	0.2%		476		
593	Emissions Cost Due Trustee	Total in-state metered Load (consists of metered load within ISO Control Area and real time gross export to other in-state Control Areas)	Emissions Cost Recovery Rate (Published by ISO)	20	0.0%		20		
594	Start-Up Cost Due Trustee	Total in-state metered Load (consists of metered load within ISO Control Area and real time gross export to other in-state Control Areas)	Start-Up Cost Recovery Rate (Published by ISO)	72	0.0%		72		
595	Minimum Load Cost Allocation Due ISO	SC in-state metered Load (consists of metered load within ISO Control Area and real time gross export to other in-state Control Areas) [per SC]	Per Unit Price = Total Minimum Load Cost Compensation paid in the month / Total Metered Load and In-state Export in the Control Area for the month	189	0.1%		189		
691	Emissions Cost Payment	Emission cost incurred by SC as a result of ISO dispatch [per SC, per location]	N/A: Set to 1	2	0.0%		2		
692	Start-Up Cost Payment	Start-up cost incurred by SC as a result of ISO dispatch [per SC, per location]	N/A: Set to 1	31	0.0%		31		
695	Minimum Load Cost Compensation Due SC	Billable Quantity paid for the month	Pseudo Price for each BA= Amount Paid in the month / Billable Quantity in the month	28	0.0%		28		
1010	Neutrality Adjustments	SC's Metered Demands in the Control Area [Per SC]	Per Unit Price = Total overcollected or undercollected revenue / Total collected user payments for Ancillary Services.	15,917	7.6%	11,938			3,979
1011	Ancillary Service Rational Buyer Adjustment	SC's user payment for Ancillary Services [per SC, per Control Area]	Per Unit Price = Total No Pay Revenue / Total Metered Demand in the Control Area	13,984	6.6%	10,488			3,496
1030	No Pay Provision Market Refund	SC's Metered Demands in the Control Area [Per SC]	Per Unit Price = Total No Pay Revenue / Total Metered Demand in the Control Area	14,805	7.0%	11,104			3,701
1061	Distribution of Preempted Spinning Reserve	SC's Metered Demands [per SC, per Zone]	Total Spinning Reserve Preemption Revenue / SC's Total Metered Demand [per AIS Region, per Trading Interval]	768	0.4%	768			
1062	Distribution of Preempted Non-Spinning Reserve	SC's Metered Demands [per SC, per Zone]	Total Spinning Reserve Preemption Revenue / SC's Total Metered Demand [per AIS Region, per Trading Interval]	1,930	0.9%	1,930			
1064	Distribution of Preempted Replacement Reserve	SC's Metered Demands [per SC, per Zone]	Total Spinning Reserve Preemption Revenue / SC's Total Metered Demand [per AIS Region, per Trading Interval]	65	0.0%	65			
1065	Distribution of Preempted Regulation Up	SC's Metered Demands [per SC, per Zone]	Total Spinning Reserve Preemption Revenue / SC's Total Metered Demand [per AIS Region, per Trading Interval]	35	0.0%	35			
1066	Distribution of Preempted Regulation Down	SC's Metered Demands [per SC, per Zone]	Total Spinning Reserve Preemption Revenue / SC's Total Metered Demand [per AIS Region, per Trading Interval]	35	0.0%	35			
1120	Est. Summer Reliab. Contract Capacity Pymt/Charge	SC's Metered Demands in the Control Area [Per SC]	Per Unit Price = Total Amount / Total Metered Demand in the Control Area	680	0.3%		680		
1121	Adj. Summer Reliab. Contract Capacity Pymt/Charge	SC's Metered Demands in the Control Area [Per SC]	Per Unit Price = Total Amount / Total Metered Demand in the Control Area	728	0.3%		728		
1210	Existing Contracts Cash Neutrality Charge/Refund	SC's Metered Demands in the Control Area [Per SC, Per Interval]	Per Unit Price = Total Amount / Total Metered Demand in the Control Area	18,023	7.8%	12,017			4,006
1302	Long Term Voltage Support due ISO	SC's Metered Demands in the Zone [Per SC]	Per Unit Price = Total Amount / Total Metered Demand in the Zone	423	0.2%		423		
1481	Excess Cost Neutrality Allocation	SC's Metered Demands in the Control Area [Per SC]	Per Unit Price = Total Amount / Total Metered Demand in the Control Area	2,519	1.2%	1,889			630
1487	Energy Exchange Program Neutrality Adjustment	SC's total Negative Uninstructed Energy during those 10-min intervals in which ISO imports energy through the Exchange Account [per SC, per region, per Exchange Account]	Per Unit Price = Cost of Exchange program / Sum of SC's Billable Quantities	8	0.0%	6			2
1999	Rounding Adjustment	SC's Metered Demands in the Control Area [Per SC]	Per Unit Price = Total Amount / Total Metered Demand in the Control Area	441	0.2%	305			94
2999	Interest - Due SC	Distribution allocation of Interest earned per SC	Pseudo price: Total settlement amount / billable quantity	32	0.0%	22			7

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Billing Determinant Stability

(Sept. 2001 through Feb. 2003)

June 30, 2003

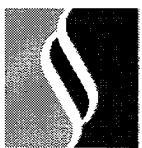
2004 GMC Rate Structure Project

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Billing Determinants Reviewed

- Non-coincident Peak
 - Purchases and sales of AS, IE and UE
- Coincident Peak
 - Purchases and sales of AS, IE and net UE
 - AS volumes (market only)
- Net Control Area Load
 - Instructed Energy
 - Uninstructed Energy
- Net Hour-Ahead Scheduled Interzonal Flows
 - Inter SC trades
 - All schedules
- Net Uninstructed Deviations
 - Maximum Net Uninstructed Deviations

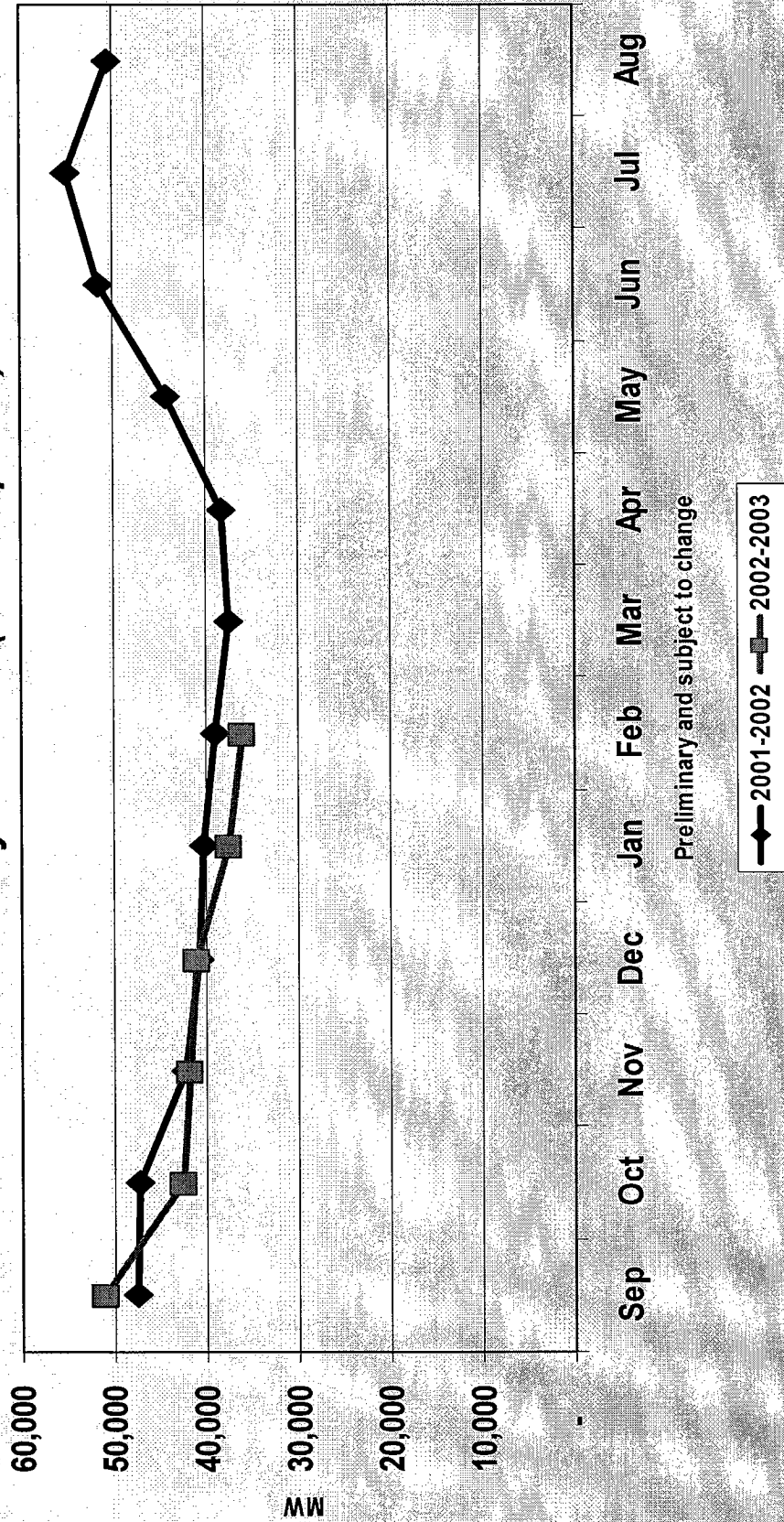


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Comparison of NCP Sept. 2001 through Feb. 2003

Core Reliability Services (ISO Proposed)

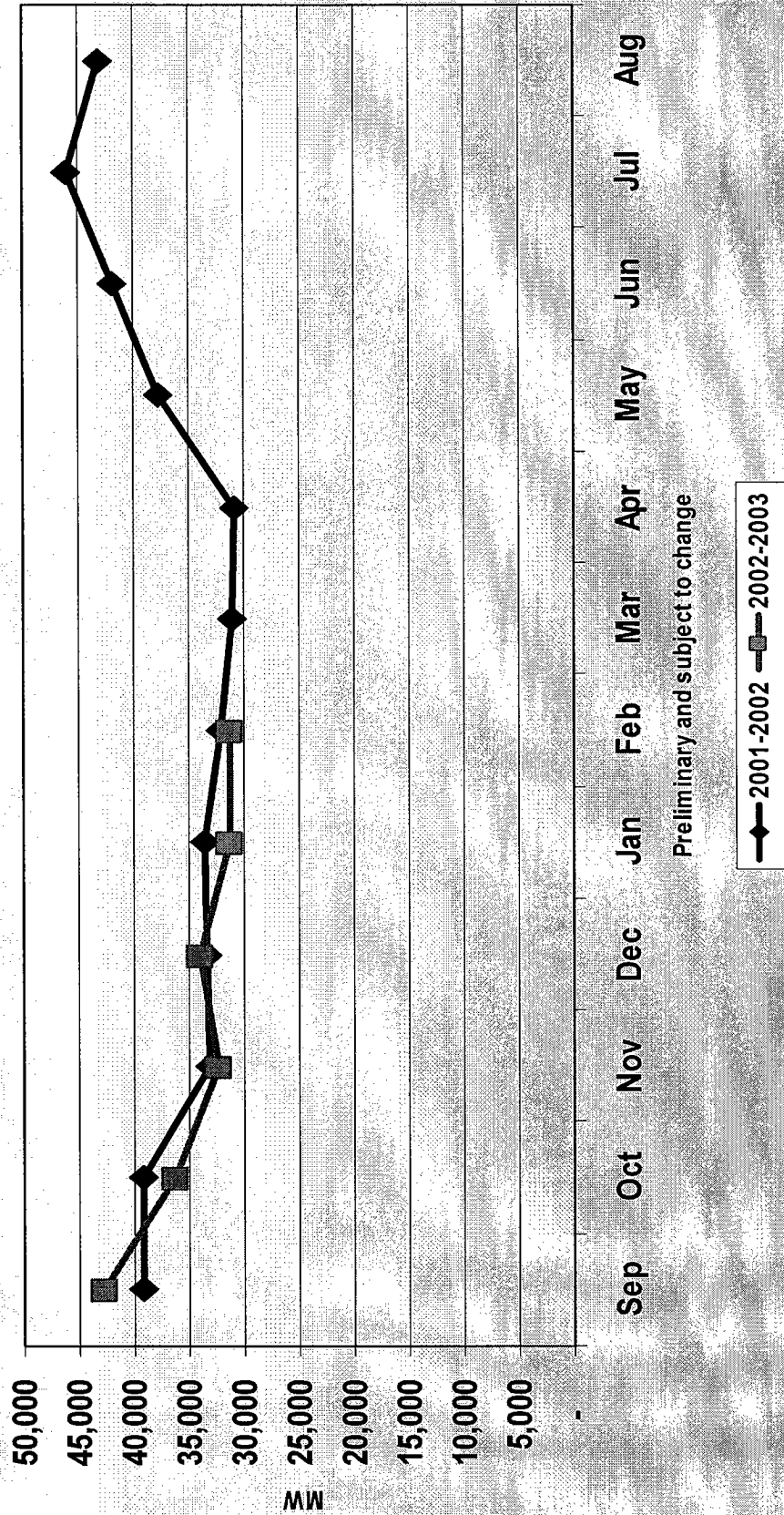




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Comparison of CP Sept. 2001 through Feb. 2003 Core Reliability Services (CDWR proposed)



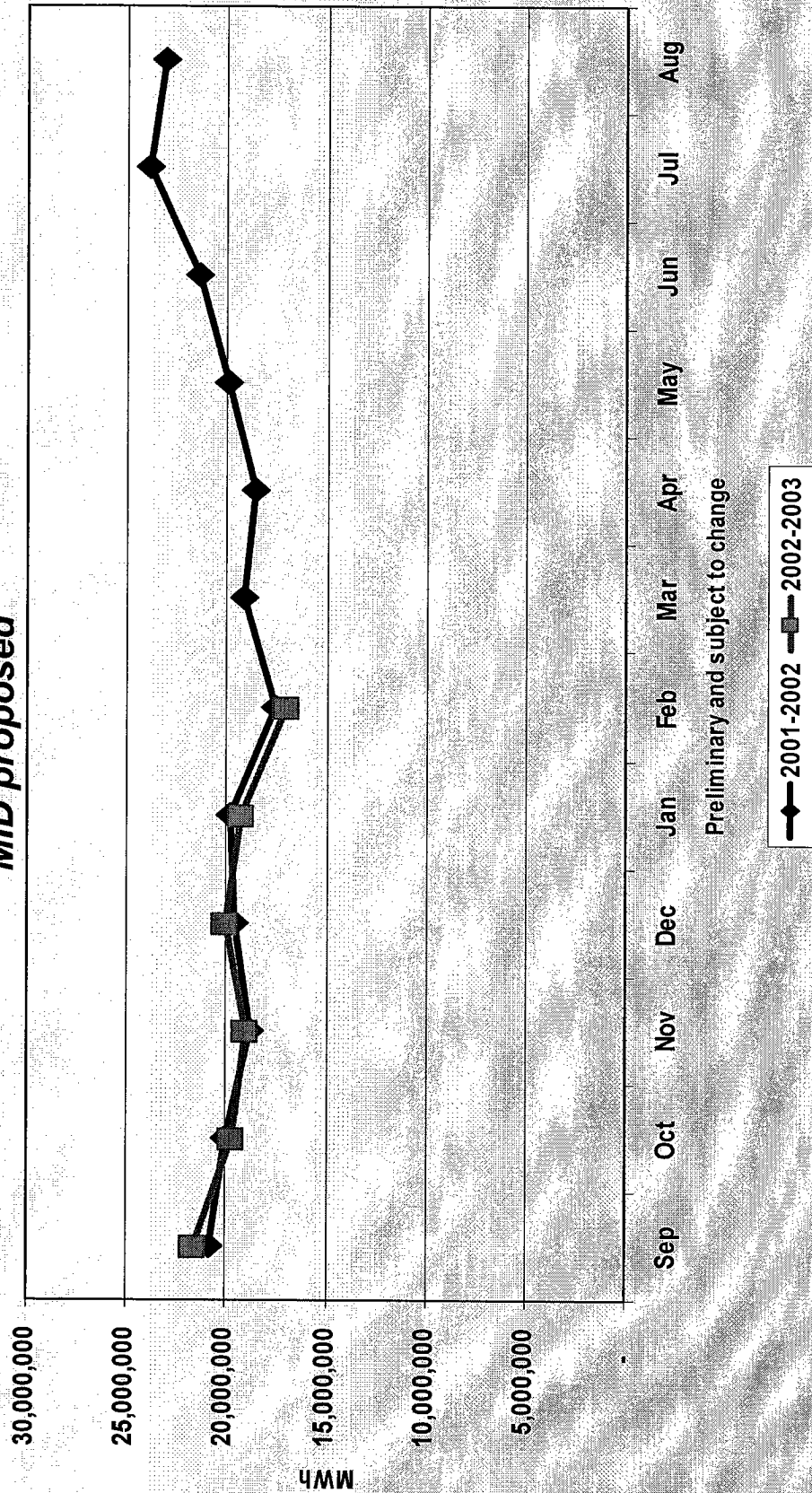


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Comparison of Net Control Area Load Sept. 2001 through Feb. 2003

MID proposed



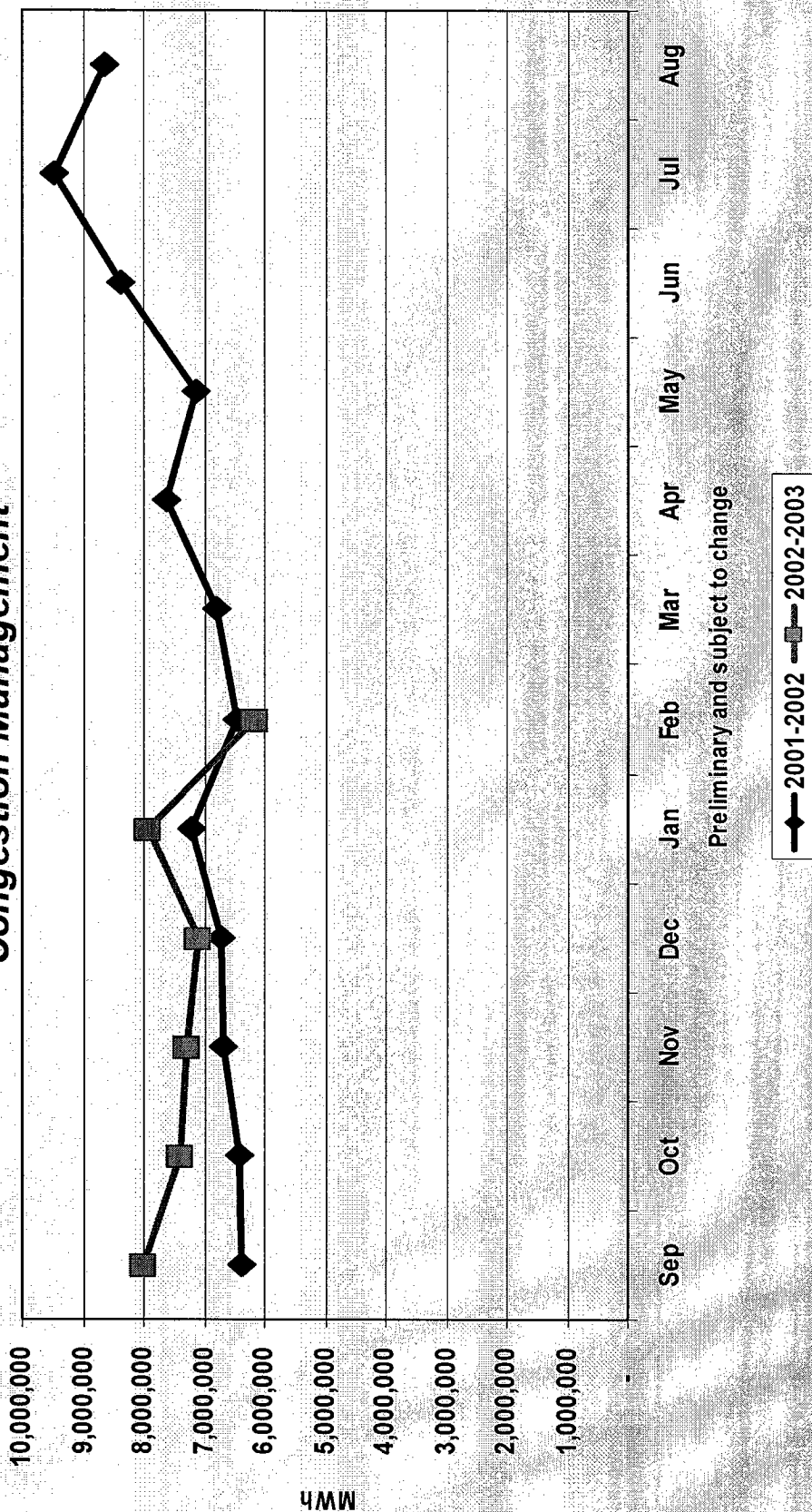


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Comparison of Net HA Scheduled Interzonal Flows Sept. 2001 through Feb. 2003

Congestion Management



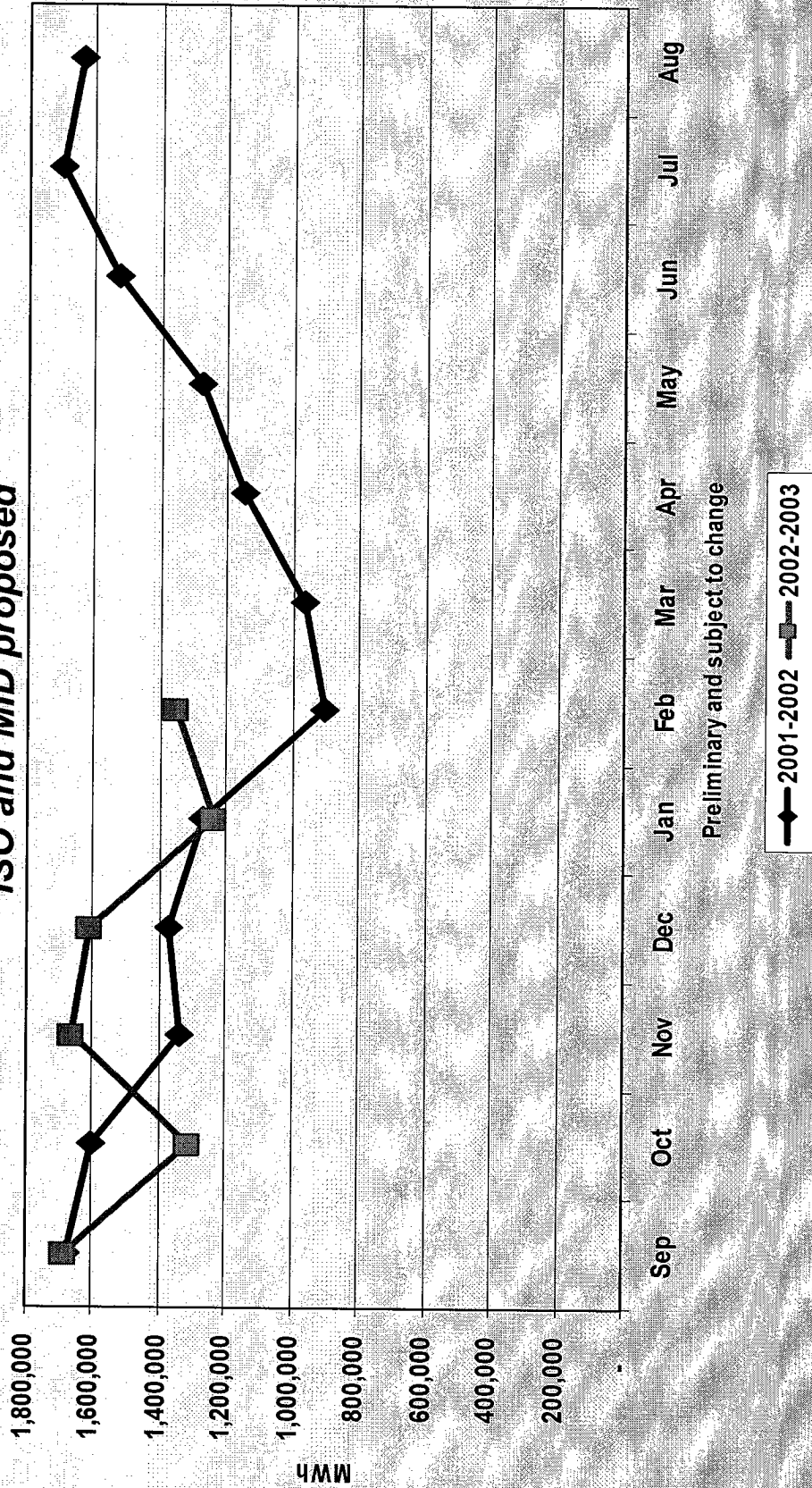


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Comparison of Net Uninstructed Deviations Sept. 2001 through Feb. 2003

ISO and MID proposed

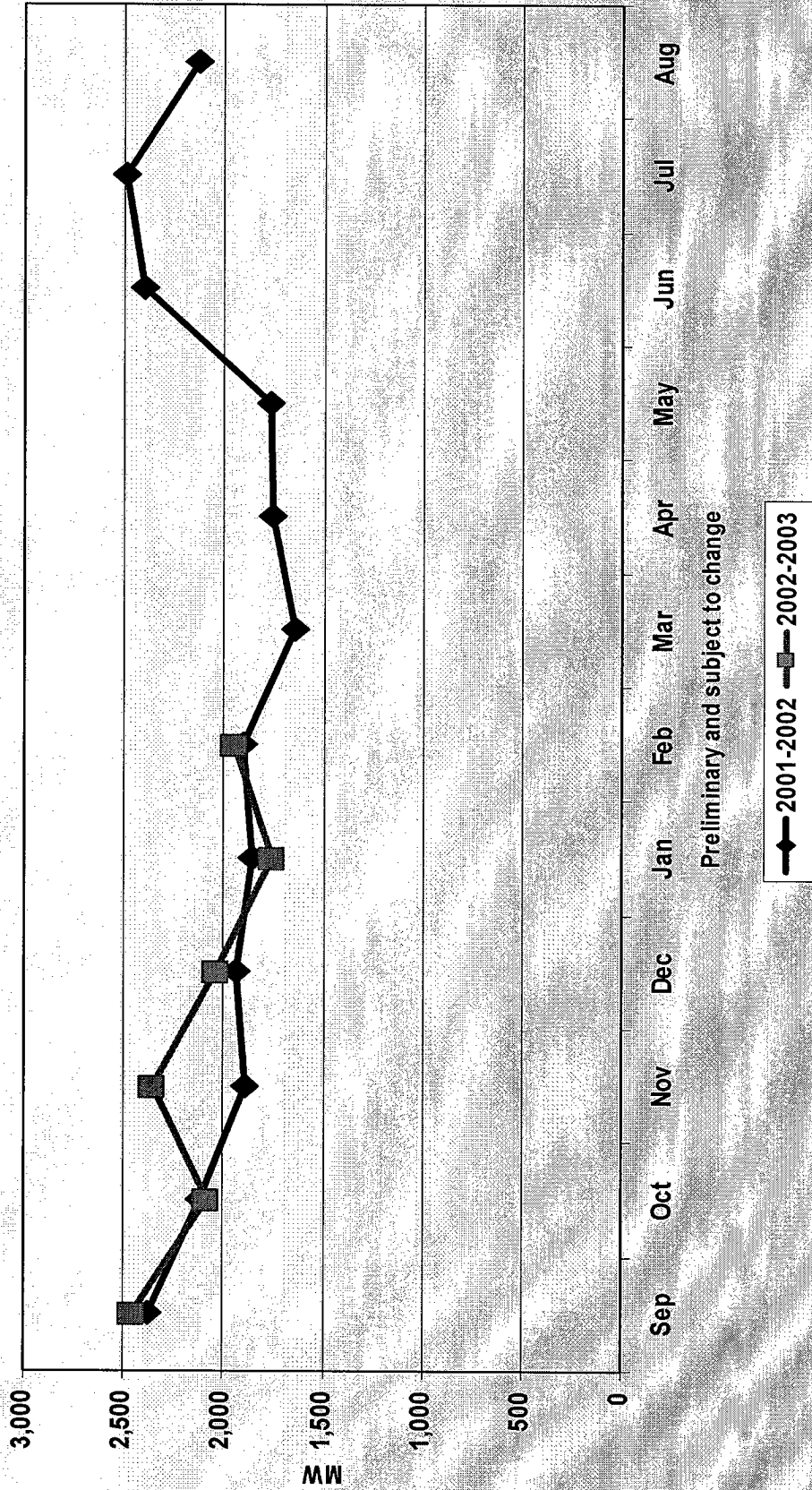




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Comparison of the Sum of the Maximum Net Uninstructed Deviations Sept. 2001 through Feb. 2003



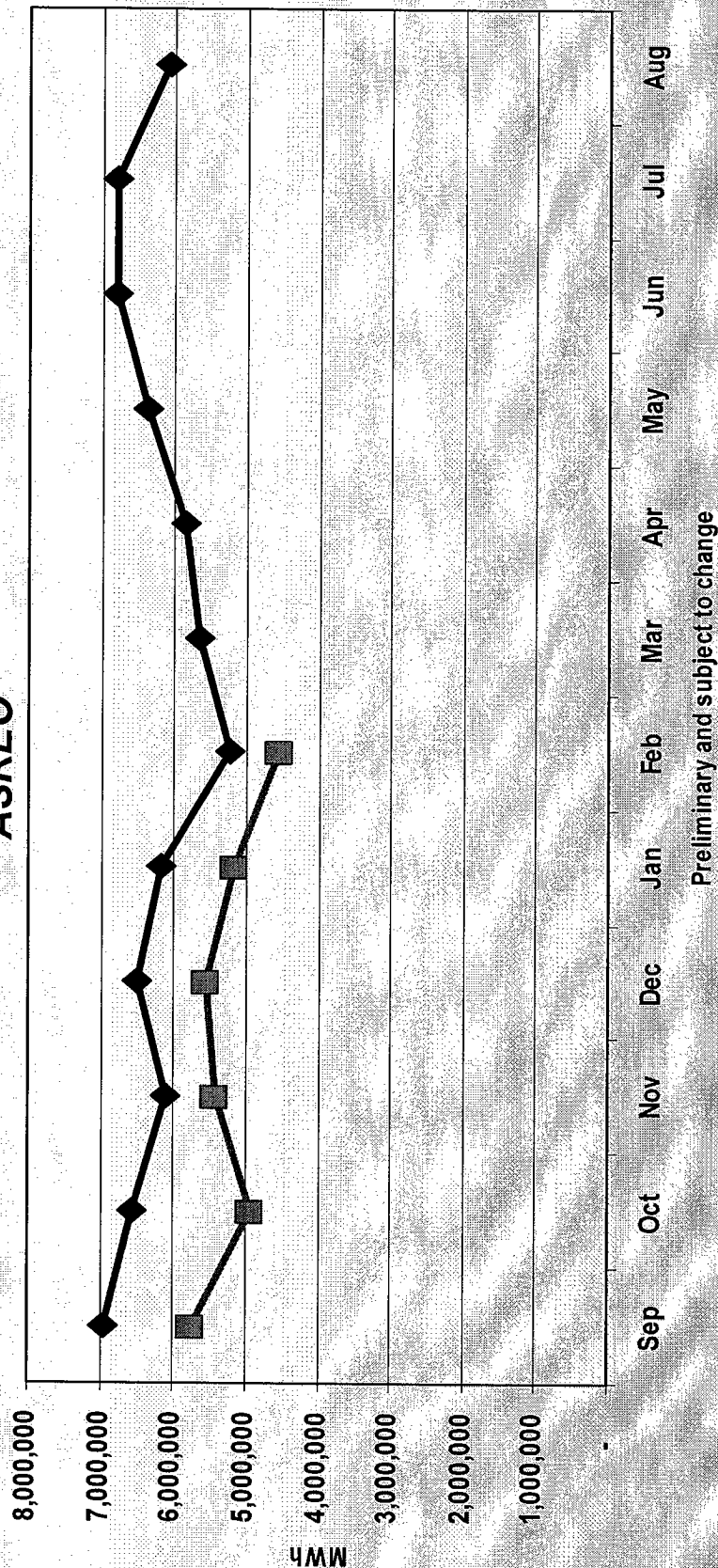


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Comparison of the Sum of Purchases and Sales of AS, Instructed Energy, and Uninstructed Deviations Sept. 2001 through Feb. 2003

ASREO

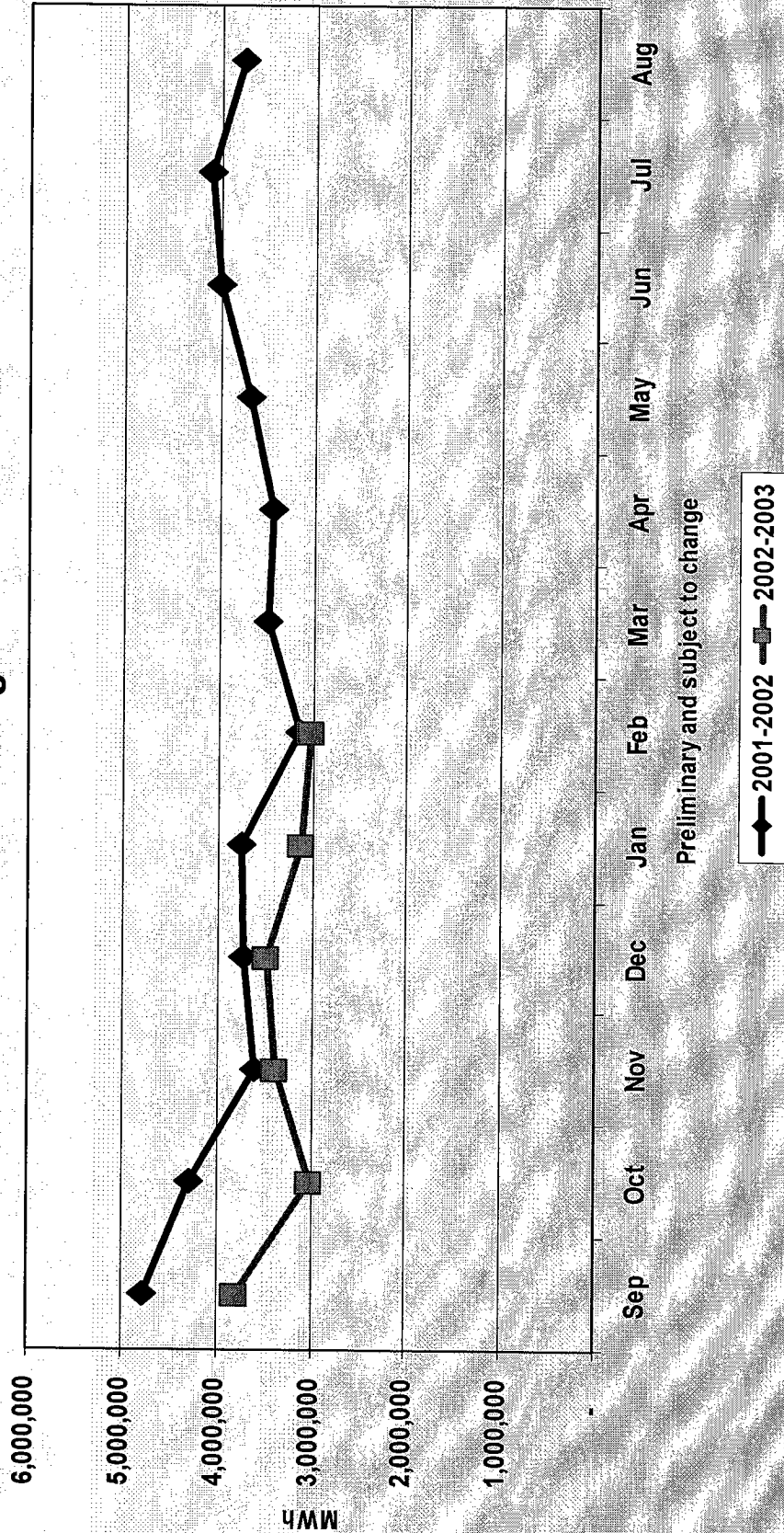




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Comparison of the Sum of Purchases and Sales of AS, Instructed Energy, and Net Uninstructed Deviations Sept. 2001 through Feb. 2003 *Market Usage*

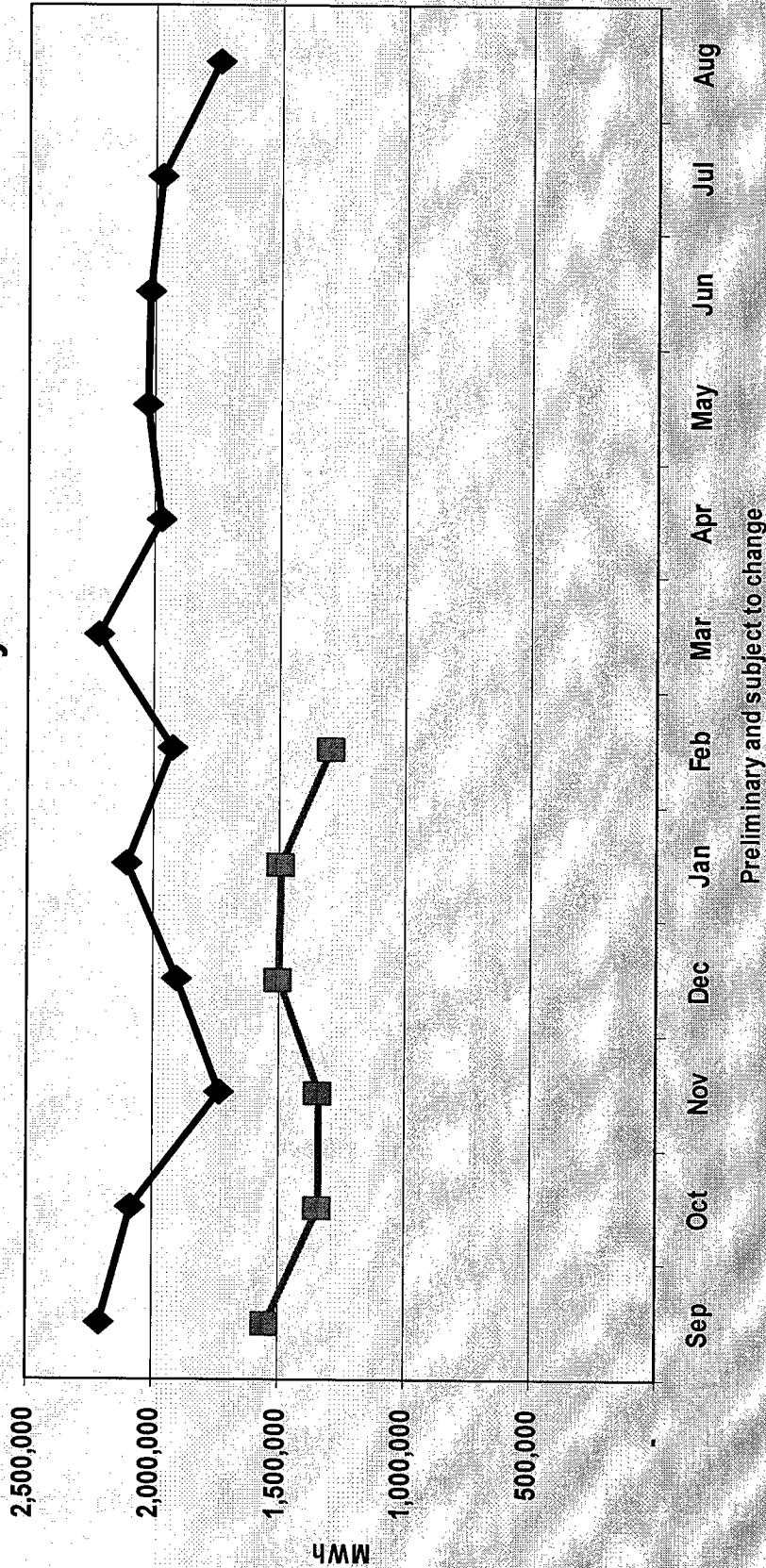




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Comparison of the Sum of Purchases and Sales of AS
Sept. 2001 through Feb. 2003
Market AS only



Preliminary and subject to change

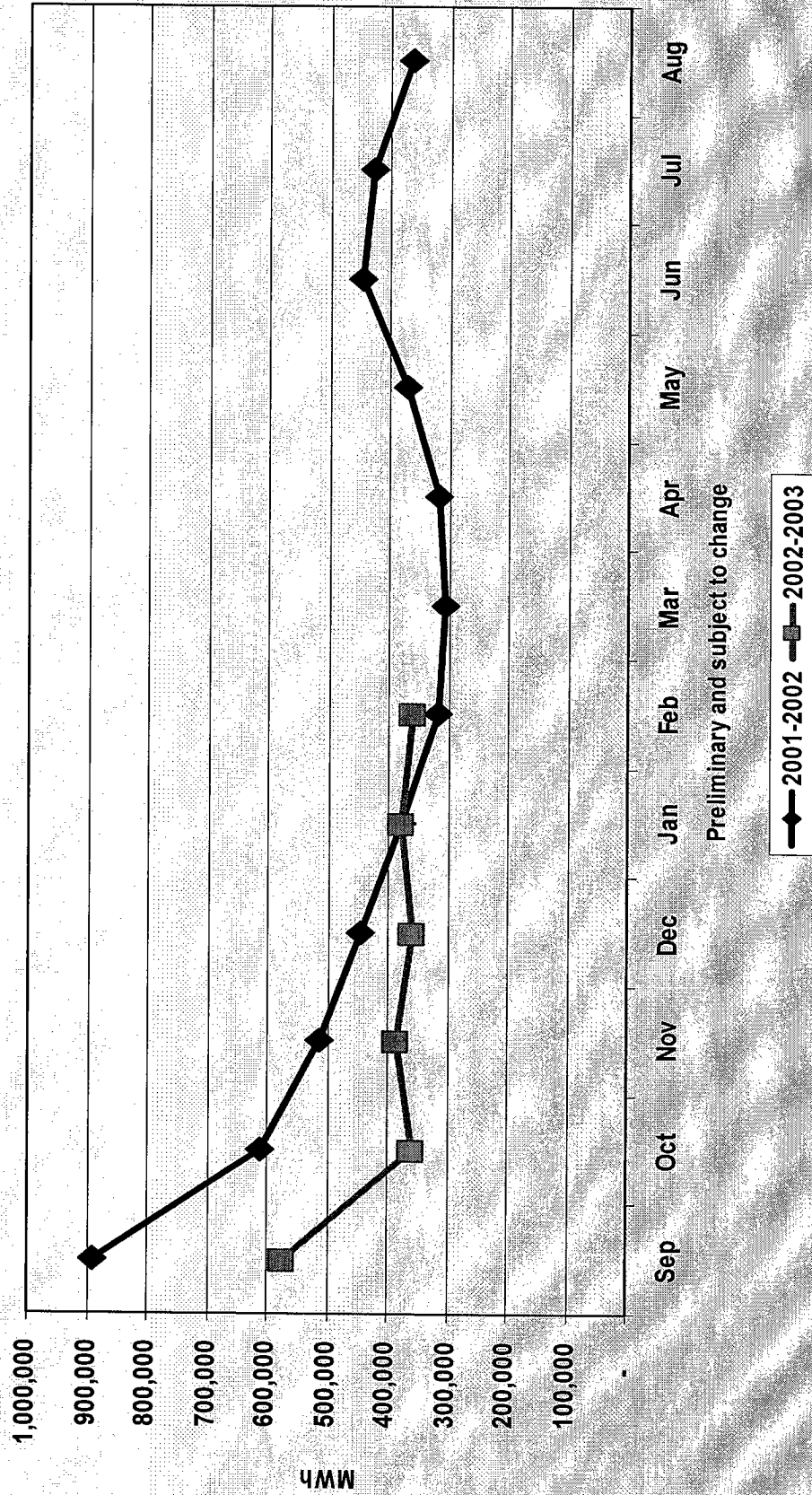
2001-2002 2002-2003



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Comparison of the Sum of Instructed Energy Sept. 2001 through Feb. 2003

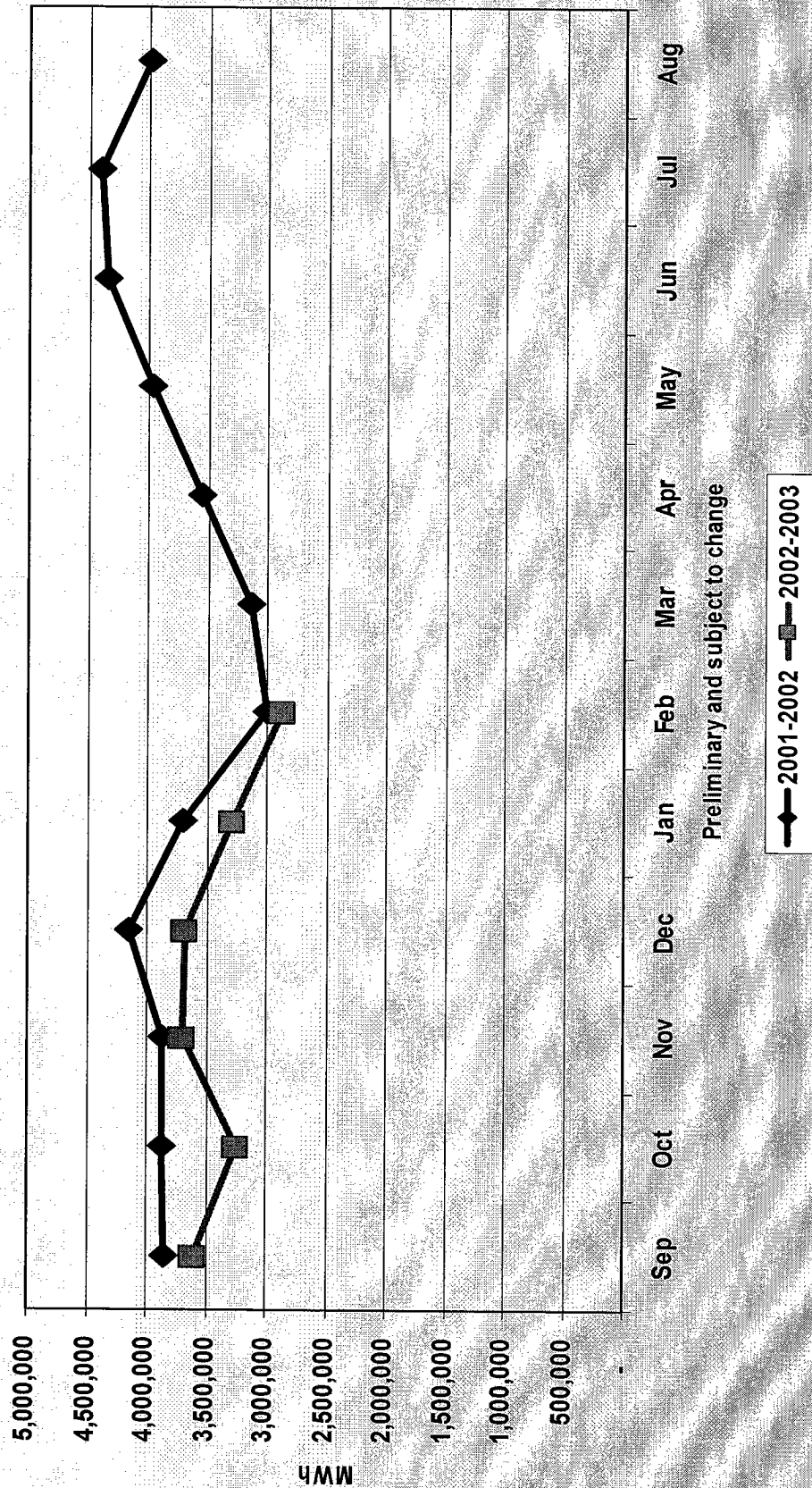




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Comparison of the Sum of Uninstructed Energy
Sept. 2001 through Feb. 2003

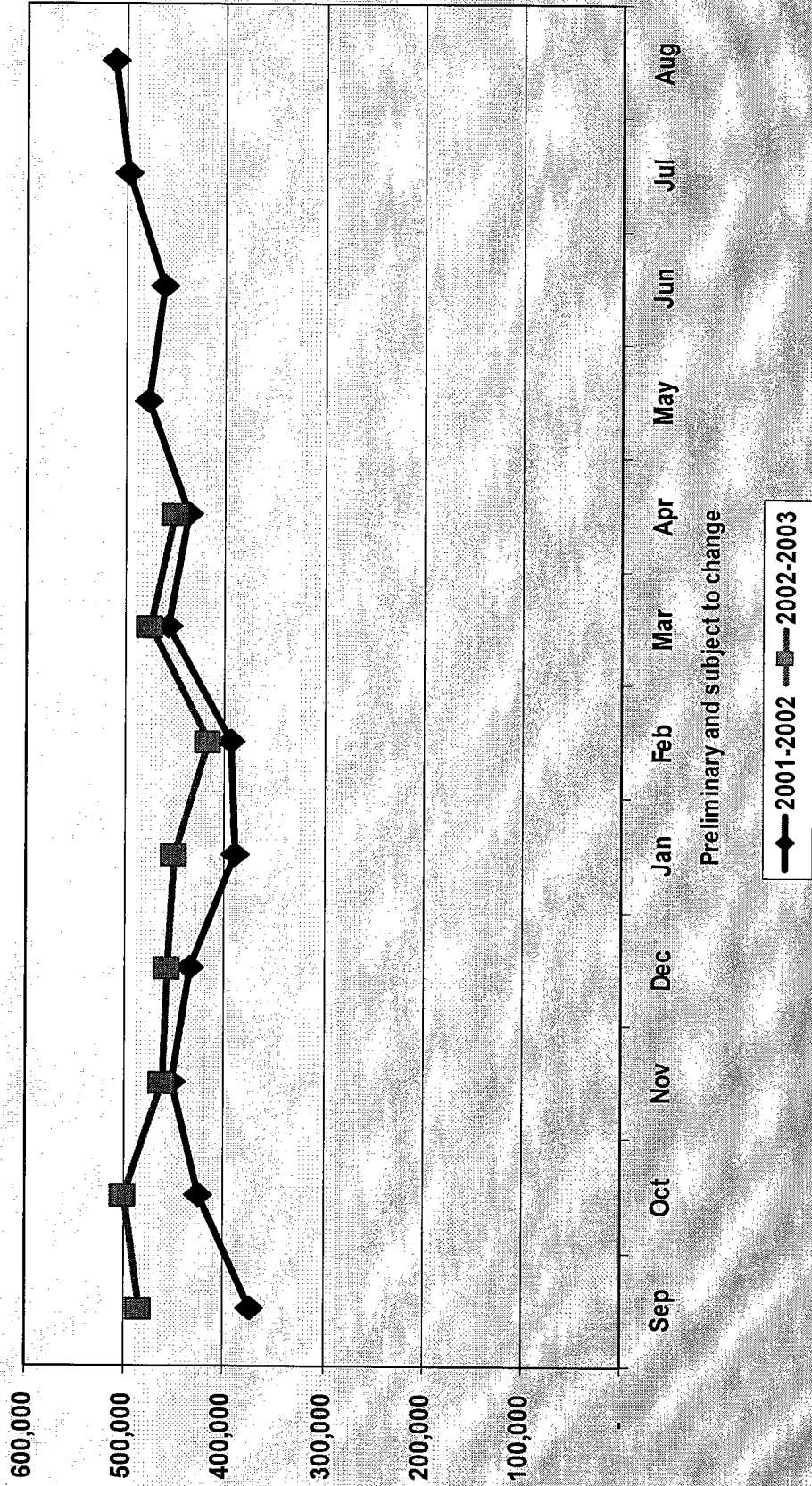




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Comparison of the Inter SC Trades
Sept. 2001 through Apr. 2003

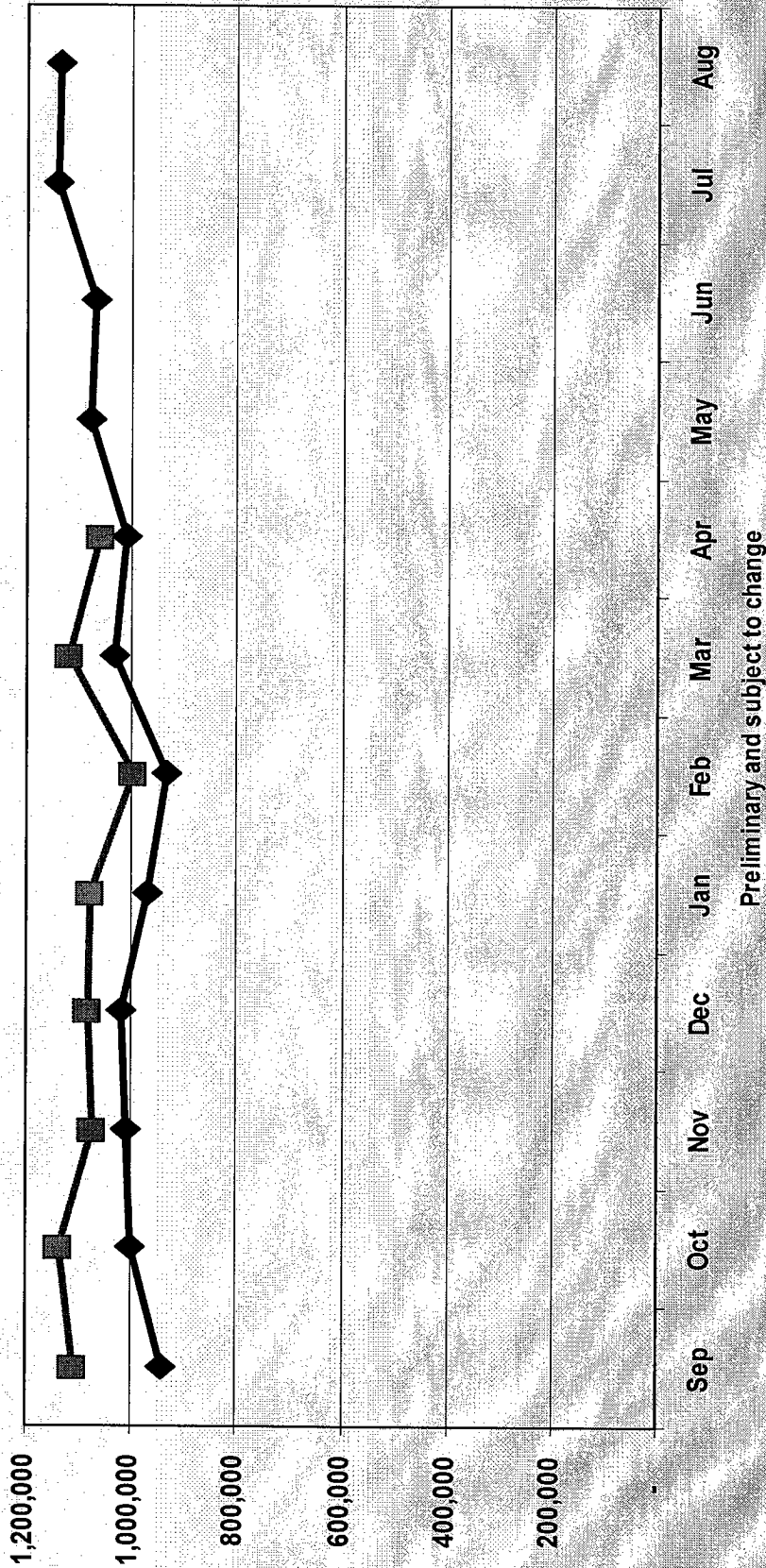




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Comparison of the All Schedules Sept. 2001 through Apr. 2003



Development of Direct Cost Assignment Factors

Barkovich & Yap, Inc.

June 30, 2003

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Define Functions

- Initial tasks involved defining ISO's functions and associated subfunctions
 - Grid Reliability Services
 - *Core Reliability Services*
 - *Energy Transmission Services*
 - Market Services
 - *Forward Scheduling*
 - *Congestion Management*
 - *Market Usage and Services*
 - Settlements, Metering & Client Relations

Subfunctionalizing Grid Services

- Numerous meetings with the Grid Ops managers to establish the definitions of core and scalable services
- Discussed Grid Ops activities by Cost Center down to the “micro” level during this process
- Established working definitions that managers used in assigning personnel between core and scalable activities

Break apart Grid Services Cost Centers Between GRS & ETS

- Identified core services, *i.e.*, basic level of reliable operation of a Control Area with similar geography surrounded by other control areas
- Identified scalable activities, *i.e.*, managing energy imbalances and transmission flows beyond those in the core Control Area.
- Determined which personnel conduct these core activities.
- Determined which personnel conduct these scalable activities.

Subfunctionalizing Market Services

- Number of meetings with managers to develop definitions of scheduling, market usage, and congestion management
- Discussions addressed Market Services activities at a “micro” level
- Established the working definitions for the managers to divide personnel at the cost center level between the three subfunctions

Break Apart Market Services between CONG, Forward Scheduling & Market Usage

- Used current definition of congestion management, *i.e.*, operation of inter-zonal congestion markets, using adjustment bids, taking Firm Transmission Rights and Existing Transmission Contracts into account, and determining the price for mitigating congestion for flows on congested paths
- Determined which personnel conduct these congestion management activities.

Break apart Market Services- cont.

- Identified forward scheduling, *i.e.*, processing, reviewing & verifying forward schedules submitted by SCs.
- Determined which personnel conduct these scheduling activities.
- Identified market usage, *i.e.*, processing bids, monitoring market performance, and determining market prices.
- Determined which personnel conduct these market usage activities.

Settlements, Metering & Client Relations

- Similar to traditional definitions associated with customer access
- Includes metering, preparing settlement statements, answering customer inquiries
- Meetings held with managers of cost centers to establish working definition for them to use in determining which personnel perform these activities

Capital Costs

- Performed analysis on a system-by-system basis
- Meetings held with technical staff from Grid Ops and Market Services
- Where it was possible to measure the traffic on a particular system, this information was used to quantify cost assignment, *e.g.*, SI system

Capital Costs-cont.

- Where no quantification was available, used information provided by technical staff about the use of the systems to determine the appropriate cost assignment
- Where system use is very broad, *e.g.*, Oracle system or PCs, used more general allocators

SCE GMC PROPOSAL UPDATE

1) SCE developed a GMC proposal and presented it to the 2004 GMC Stakeholder group.

2) The May 2, 2003 FERC Final Order in the ISO's 2001 GMC case provides guidance that SCE believes is appropriate to consider in developing the 2004 GMC.

- A demand charge applied to "Grid Demand" would be a non-discriminatory and comparable way to charge for Control Area Services.
- Grid Demand is defined to be the demand that a Scheduling Coordinator places on the ISO Grid.
- A Grid Demand charge would eliminate the issue of estimating retail behind-the-meter load.
- A grid Demand charge would eliminate the issue of which party should be billed for all retail and wholesale behind the meter load.

3) The Final Order guidance is applicable to both the SCE and the ISO's GMC proposals, in the sense that each would need to be modified to be consistent with the Final Order.

4) In light of the Final Order guidance, and other long-standing SCE issues that were incorporated within SCE's GMC proposal, SCE is willing to support the ISO proposal if the following modifications are made to it:

- a) The ISO should use a billing determinant of Grid Demand for the Core Reliability Services (CRS) charge)
- b) Grid Demand should be measured comparably for all entities.
 - If an SC has load and generation on a distribution circuit, that should not contribute to the GMC Grid Demand billing determinant.
 - Grid Demand should include exports, but exports should not include any Mohave Participant energy, SWPL energy, or COTP energy (anything delivered to other control areas over non-PTO transmission).
- c) The Energy and Transmission Services (ETS) charge should be assessed only to exports that use the ISO controlled grid.
- d) The billing determinant for the ETS charge should not include an SC's distribution-level load served by distribution-level generation.
- e) In the event that exports are determined to include energy that is the load responsibility of another control area delivered over non-PTO transmission facilities, there should be appropriate treatment for the CRS and ETS charges: an assessment equal to 10% of these rates.

SDG&E WHITE PAPER - 2004 GMC PROPOSAL
Applicability to APS and IID ownership shares of the Southwest Powerlink

San Diego Gas & Electric ("SDG&E") submits this white paper to the California Independent System Operator ("ISO") and Grid Management Charge ("GMC") Stakeholder participants for their consideration. This paper sets forth SDG&E's concerns with the ISO's 2004 GMC proposal as applied to energy schedules of Arizona Public Service ("APS") and Imperial Irrigation District ("IID") on their respective ownership shares of the Southwest Powerlink ("SWPL").

Assumptions and Conclusions

As a preliminary matter, SDG&E maintains that the ISO should not bill SDG&E for, nor otherwise apply, *any* of the seven GMC "buckets" to the subject APS and IID service, because the APS and IID portions of SWPL have not been turned over to ISO Operational Control, and because applying GMC to such schedules violates the ISO Tariff, FERC precedent, and principles of reciprocity that have long governed relationships among control areas in the WECC. The SDG&E and ISO contentions in this regard are in litigation before the FERC, and therefore should be known to all the stakeholders, so we will not repeat them here. This paper assumes that the ISO will maintain its position for 2004 that it can properly apply GMC to the non-ISO participant SWPL shares. Given this assumption, this paper examines whether specific portions of the 2004 GMC proposal should otherwise apply to the subject schedules.

In sum, we conclude the billing determinants the ISO proposal uses to derive the unbundled rates for each of the buckets are overstated as a result of inappropriate inclusion of the APS/IID schedules in the billing determinants. Due to this overstatement of billing determinants, the ISO's unbundled GMC rates for each bucket are understated.

SWPL Background

In 1983 SDG&E completed construction of SWPL, a 292 mile 500 kV transmission line from its Miguel substation to the Palo Verde switchyard in Arizona. Pursuant to contracts executed in 1981 and 1983 ("Participation Agreements"), SDG&E transferred portions of SWPL to APS and IID. As a result, the Palo Verde – North Gila segment of SWPL is owned jointly by SDG&E, APS and IID in the ratio of 76.22%, 11% and 12.78%, respectively. APS and IID each operate and control their own portions of SWPL. APS uses its portion of SWPL to deliver energy to its retail load at APS's North Gila substation in Arizona. IID uses its portion of SWPL to deliver energy to its retail load in the Imperial Valley at the Imperial Valley substation (IID also owns a portion of the North Gila – Imperial Valley segment of SWPL). APS and IID are fully-resourced utilities that operate their own control areas, and secure their own reserves and ancillary

services. Their retail loads lie within their respective control areas; put conversely, the APS and IID loads lie *outside* the ISO control area.

In addition, the Participation Agreements oblige APS and IID to reimburse SDG&E for line losses on their respective shares of SWPL by returning energy in kind based on an algorithm derived from actual measured flows. Under the Participation Agreements, SDG&E is the “Scheduling Agent,” and is thereby obliged to give effect to SWPL schedules submitted to it by APS and IID. After the ISO began operation, SDG&E was obliged to give effect to the APS and IID schedules by acting as the “middleman” and handing off the APS and IID schedules to the ISO. But the ISO cannot direct APS and IID as to the quantity, source or duration of any energy each may schedule on its respective share of the line. Nor does the ISO list the APS and IID SWPL shares as “ATC” on the ISO OASIS; such shares are not treated by the ISO as available to ISO customers and market participants. Third-party use of such shares must be arranged with APS and IID.

APS and IID Schedules Are Not “Exports”

One basis under which the ISO proposes to assess GMC on these schedules is that these schedules constitute “exports” from the ISO control area. But the APS and IID schedules do not contribute to the ISO Load responsibilities or to the ISO Control Area responsibilities. These schedules therefore do not cause the ISO to incur additional costs, and should not give rise to GMC.

The proposed billing determinants include Load and Exports (“Export” is not currently defined in the ISO Tariff). In this context, any Net Export when added to the ISO’s Load appears to be a net load served by the ISO. The ISO explains that one reason that Loads and Exports are charged the GMC is they are the “responsibility” of the ISO, as Control Area operator. The ISO describes the Control Area responsibilities that it fulfills for all loads within its Control Area that are considered part of its “Load Responsibility.” That justification simply does not apply to the APS and IID schedules on SWPL. The many load-related services described by the ISO are *not* services provided to the APS and IID schedules on SWPL because the APS and IID schedules on SWPL are *not* part of the ISO’s Load Responsibility (the ISO Tariff defines Load as “an end use device of an End Use Customer that consumes power” – a definition that cannot be stretched to APS and IID load by the mere fact that SWPL itself is in the ISO control area). Because APS and IID are fully-resourced utilities securing all energy reserves and other ancillary services to serve their respective loads in their separate control areas, APS and IID schedules on SWPL are the Load Responsibility of APS and IID, not the ISO. Since the generation serving the APS and IID loads are external to the ISO, every “export” from the ISO Control Area on SWPL is matched by a corresponding import, thus the Net Export associated with the APS and IID schedules is zero (exclusive of transmission system losses, which are the subject of a separate dispute).

Moreover, under the WECC's Minimum Operating Reliability Criteria ("MORC"), a Control Area operator is required to carry operating reserves for its "Load Responsibility." APS and IID schedules on SWPL, however, do not contribute to the Load Responsibility of the ISO Control Area because this energy is APS and IID's Load Responsibility as Control Area operators. Thus APS and IID as operators of separate Control Areas must provide the spinning reserves required to support their schedules on SWPL. And in fact APS and IID, and not the ISO, provide such spinning reserves.

In contrast, energy typically exported outside of the ISO Control Area is considered part of the ISO's Load Responsibility. For example, a Wheeling Out export from generation originating within the ISO Control Area to another Control Area would contribute to the Load Responsibility of the ISO, and as such would add to the Operating Reserves that the ISO would have to secure in order to "back-up" that export so as to maintain WSCC MORC requirements.

APS and IID retail customers do not benefit from ISO GMC services

Even if SWPL Energy (the APS and IID schedules to their respective loads) requires the ISO to perform some minor work, this incidental effort attendant to APS and IID schedules on SWPL does not justify imposition of the ISO GMC. Each and every Control Area operator in the WSCC must perform the same functions that comprise the ISO's Control Area Services. Coordination among Control Areas falls within the WECC reciprocity requirements. ISO coordination of the APS and IID schedules is no different than the coordination of ISO energy scheduled by APS and IID within their respective Control Areas. If, for example, when the ISO schedules on the Four Corners – Moenkopi Line, which is under the ISO's Operational Control in APS's Control Area, APS will be responsible for scheduling coordination and control area integration service of the sort the ISO characterizes as control area services. But APS does not charge the ISO for those services.

As recognized by the WECC requirements, such coordination is inherent in the interconnected operation of Control Areas. Due to the reciprocal nature of the duty, it is inappropriate for one operator to unilaterally assess such charges based solely on interconnected operation with another control area.

Evaluation of the ISO's proposed Billing Determinants as applied to APS and IID SWPL shares

We set forth below the ISO's proposed Rates and billing determinants as defined by the ISO's document dated 4/25/03, and summarize the applicability to the subject SWPL schedules:

1. Core reliability
 - a. Determinant = Gross non-coincident peak demand MW (Load + Export)
 - b. The APS and IID schedules to their respective loads are not part of the ISO's load responsibility. Further, since the Net Export is zero for the APS and IID schedules to their respective loads (each such export has a corresponding import, for a net zero Export), the APS and IID schedules (exclusive of transmission system losses) have no effect on the ISO's Gross non-coincident peak demand.
2. Energy & Transmission Services – Load
 - a. Determinant = Net Control Area Load (Controlled Grid Load) + (Export)
 - b. The APS and IID schedules to their respective loads are not part of the ISO's load responsibility. Further, since the Net Export is zero for the APS and IID schedules to their respective loads (each such export has a corresponding import, for a net zero Export), the APS and IID schedules (exclusive of transmission system losses) have no effect on the ISO's Net Control Area Load.
3. Energy & Transmission Services – Deviation
 - a. Determinant = Absolute value of net uninstructed deviations by settlement interval (MWh)
 - b. Aside from the ongoing dispute regarding transmission losses associated with the APS and IID schedules, at a minimum the ISO should credit SDG&E's self-provision of losses for APS and IID. We believe this is the intent of the ISO's proposal, based on the ISO answer to SDG&E's complaint in Docket NO. EL03-131-000.
4. Scheduling
 - a. Determinant = Number of Final Hour-Ahead schedules returned by Scheduling Infrastructure
 - b. Scheduling should be excluded on the principle of reciprocity (the ISO is not charged by other Control Areas for schedules on transmission under the ISO's Operational Control in those other Control Areas).
5. Congestion Management
 - a. Determinant = Hour-ahead net inter-zonal New Firm Use flow (excludes ETCs)
 - b. The ISO does not perform services in this category for the APS and IID schedules.
6. Market Usage
 - a. Determinant = Purchases and sales of Ancillary Services, instructed energy, and absolute value of net uninstructed deviations

- b. The ISO does not perform services in this category for the APS and IID schedules (there is no market participation involved; rather, APS and IID serve their own loads with generation sources of their own choosing exclusive of the ISO).

7. Customer Service

- a. Determinant = Min \$500/month fixed charge + \$.0289
 b. We are unaware of any "Customer Service" provided by the ISO to APS or IID in connection with their schedules.

Therefore the ISO 2004 GMC billing determinants should be revised accordingly.

Rate Impact of GMC on APS and IID SWPL schedules

The total amount of GMC charges associated with the APS and IID schedules currently is about \$2.17 million annually; based on the ISO's new 2004 GMC projection, GMC charges will be reduced to \$1.3 million annually.

ISO Current GMC	Current CAS	Current CONG	Current ASREO	Total				
APS/IID Annual Billing Determinants	1,939,397	21,082	1,118,624					
APS/IID Annual Charges	\$ 1,062,572	\$ 6,570	\$ 1,104,139	\$2,173,28				
ISO Proposed 2004 GMC	Core Reliability Services	Energy & Transmission Services Load	Energy & Transmission Services Deviation	Forward Scheduling	Congestion Management	Market Usage	Settlements, Metering and Client Relations	
APS/IID Annual Billing Determinants	4,263	1,939,397	34,121	48,098	21,082	34,121	12	
APS/IID Annual Charges	\$ 746,723	\$ 423,633	\$ 27,542	\$ 74,407	\$ 3,454	\$ 32,570	\$ 6,000	\$1,314,32

Conclusion

In summary, for the reasons given above, the ISO's proposed 2004 GMC rates are incorrect due to the use of the incorrect billing determinants being used to derive the unbundled GMC rates.

Agenda

2004 GMC Rate Structure Project
California ISO, Folsom
Monday, June 30, 2003
10:00 a.m. to 3:00 p.m.

Public Session (10:00 am – 12:45 pm)

Conference Call-in #1-888-788-6681 Passcode: 98563

1. Introductions/roll call
2. Updates
 - a. SCE proposal
 - b. MID proposal
 - c. ISO proposal
3. SDG&E issues
4. ISO topics
 - a. Discussion of use of non-coincident peak
 - b. Discussion of functional association of charge types
5. Discussion of timeline

Over lunch

6. Data
 - a. Billing determinant stability
 - b. Data verification

Confidential Session (1:00 pm – 3:00 pm)

Conference Call in #

7. Discussion of cost allocation method
8. Bill impact analysis update

List of attendees is attached at the end of these notes.

DRAFT Notes

The meeting began with an update of SCE's proposal given by Bert Hansen. SCE offered to drop its proposal and support the ISO proposal under two conditions. First, the correct billing determinant of Core Reliability and Energy and Transmission Services should be grid demand net of generation at distribution level. Bert said that SCE estimated that the generation connected at distribution level was approximately 6 percent of its load. Second, exports should be defined so that flows over Eldorado from Mohave, the Southwest Power Link and the California Oregon Transmission Project would be excluded.

There was a long discussion on the implications of these changes on rates. SDG&E did not have an estimate of the amount of generation connected at distribution level. PG&E was not present for this portion of the discussion. The CPUC requested that SDG&E and PG&E develop estimates. David Cohen said that he was not willing to support these changes as there was no cost basis for the exemption on certain exports. CDWR agreed with Mr. Cohen. Some of the other participants saw some merit in SCE's proposed "tweaks." There was no action plan as a result of this discussion.

MID gave a short update on its proposal. Nothing much had changed. Jan Pritchard noted that Laurence Kirsch was working on some minor tweaks.

The ISO gave a short update on its proposal. David Cohen had some edits and comments to the ISO white paper and asked if it was the appropriate time to go over them. It was and Mr. Cohen proceeded to discuss his comments and edits. Many of the comments were clarifications. There was not sufficient time for Mr. Cohen to go through all his comments, so the ISO agreed to talk with him outside the meeting.

Ali Yari of SDG&E next gave a presentation on why the flows on the SWPL to APS and IID should be exempted from all GMC assessments. There were some questions concerning the ability of the ISO to identify these flows separately. SDG&E reports the APS/IID SWPL flows under a separate ID, so that they are easily identified.

During lunch, the stability of billing determinants was discussed. (The presentation and the spreadsheet containing the data used to develop the charts are available and have been distributed to the GMC WG.)

The timeline was next discussed. It was agreed that, for the purposes of making presentations before the ISO Finance Committee on July 17th, the data would continue to be for September 2001 through August 2002. This would simplify the development of the presentations and reduce the possibility of errors. A conference call was tentatively set for July 8th to discuss any updates to proposals and to inform participants of the agenda for the Finance Committee meeting.

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After lunch, CDWR asked about rationale behind using non-coincident peak instead of coincident peak. The ISO response was to explain that the nature of monitoring and maintaining reliability required around the clock staffing and operation of the control room. The work was not related to the system peak, but to events that could happen anytime of day. To the extent an SC peaked in the off-peak, there was still work that the ISO needed to do and a contingency in the off-peak would be met with the same level of commitment as an on-peak contingency.

CDWR argued that transmission related costs should be recovered with using coincident peak as that was consistent with cost causation and FERC precedent.

There was some confusion at this point as what began as a public discussion of capital costs led to questions concerning confidential cost and or cost assignment information. It was decided that the public session would end and a confidential session would begin so that CDWR and David Cohen could ask their pointed questions.

Mr. Cohen wanted more detail concerning the process the Barkovich & Yap following in developing the cost assignments for system applications. Brian Rahman, manager of Market Engineering, explained the procedure from his perspective.

There was a discussion of how debt service was assigned started by some questions from CDWR.

At the end of the meeting, Mr. Cohen requested a focused conference call just to address CDWR's and his concerns and questions about cost assignments. It was agreed that this call would take place on Monday July 7th and would take the place of the previously agreed to the July 8th conference call.

California ISO
2004 GMC Rate Structure Project
Contact List for June 30, 2003 meeting

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4	Bonaly	David	CDWR	(916) 574-0663	bonaly@water.ca.gov	x	
5	Cogdill	Jan	ISO			x	
6	Cohen	David	Navigant Consulting	(503) 708-7852	dcohen@navigantconsulting.com	x	
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20	Springer	John	ISO		jspringer@caiso.com	x	
21	Terry	Lee	CDWR	(916) 574-0664	lterry@water.ca.gov	x	
22	Yap	Catherine	Barkovich and Yap			x	
23	Yari	Ali	SDG&E			x	
24	Auclair	Phil	Mirant	(925) 287-3144	philippe.Auclair@mirant.com		x
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27	Kaplan	Katie	IEP	(916) 448-9499	kaplan@iepa.com		x
28	Key	Jennifer	SCE				x
29	Kissel	Peter	CDWR				x
30	Paradise	Theodore	ISO				x

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Updated aggregated data 07-03-03.txt

From: Arikawa, Ben
Sent: Thursday, July 03, 2003 12:41 PM
To: Pritchard, Jan; Hemphill, Ross; Kirsch, Laurence
Subject: Updated aggregated data

Attached is a spreadsheet that contains most of the aggregated data that is being used by the various proposals. I have not yet finished the notes to all the determinants, but I'm supplying the data to you as you are thinking of using the Controlled Grid Load plus exports billing determinant. That data is located on the "Net Cont Grid Load" tab. The Tariff definition of Controlled Grid Load (aka Gross Load, for the purposes of the Transmission Access Charge).

The updated UE data will be sent out Monday or Tuesday of next week via Federal Express.

Let me know if you have any questions.

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Agenda

2004 GMC Rate Structure Project
California ISO, Folsom
Monday, July 7, 2003
1:30 p.m. to 4:00 p.m.

- I. Barkovich & Yap Presentation on Cost Assignment Method
- II. Settlement, Metering, and Client Relations cost assignment
- III. Functional association of charge types
- IV. Core Reliability cost assignment
- V. Description of capital cost assignment method
- VI. Description of cost center 1424 cost assignment method

See below for notes and list of participants.

Prior to the meeting, the ISO had distributed to all potential participants a zipped file containing seven documents. These were identified and numbered at the beginning of the call. These were:

1. Development of Direct Cost Assignment Factors, by Barkovich & Yap. Presentation partially given during June 30th GMC meeting. (Non-confidential)
2. Portion of 2003 Budget Cost Allocation Matrix with Settlements, Metering and Client Relations cost assignments shown. (Confidential)
3. Association of Settlements System with Functional Categories. (Non-confidential)
4. Portion of 2003 Budget Cost Allocation Matrix with Core Reliability cost assignments shown. (Confidential)
5. Portion of 2003 Budget Cost Allocation Matrix with Capital cost assignments shown. (Confidential)
6. Portion of 2003 Budget Cost Allocation Matrix with Capital Spending Unbundling Information (confidential)
7. Portion of 2003 Budget Cost Allocation Matrix with Cost Center 1424 cost assignments shown. (Confidential)

Cathy Yap started the meeting with the presentation on the development of cost assignment factors (Document 1). Cathy described the method of interviewing and surveying managers and directors of the respective cost centers. Barkovich & Yap and ISO Finance staff worked with groups and not with individuals. This general procedure was followed:

1. Definition, discussion and review of ISO functionalization
2. Discussion of general cost assignment method and labor assignment templates
3. Completion of templates by managers and directors, review by Barkovich & Yap and ISO Finance
4. Discussion of preliminary results and potential inconsistencies with managers and directors
5. Managers and directors revise templates in response to discussion or justify initial results.

David Cohen asked if managers and directors were asked to assign staff with MD02 activities in mind. The ISO answer was no, that these assignments are based on

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current activities. Mr. Cohen asked if there would be a separate cost assignment when MD02 would be implemented. This was possible.

Peter Kissel asked what capital expenditures were broadly assigned other than Oracle and PCs and how these costs were assigned. The response was that most of broadly assigned capital costs were in Asset Management (cost center 1424) and that would be discussed at later in the meeting.

The next subject was the cost assignments for Settlements, Metering and Client Relations (Document 2). Mr. Cohen asked if contractors were assigned to specific functions rather than generally. He argued that to the extent that the ISO provided equipment and office space for them, contractor costs should be directly assigned. He asked for definitions to the various cost assignment methods identified in the Cost Allocation Matrix as some seemed duplicative. The ISO pointed out that some of the contractors were substitutes for regular employees that might be on leave and that, in other cases, the contractors brought their own equipment with them.

Mr. Cohen asked what were the costs of contractors, excluding the MCI contract. Mr. Leiber stated that these costs were about \$10 million in O&M for in-house consultants and about \$2-\$3 million for contract staff and temps. Jan Cogdill pointed out that some consultant costs were attributed to capital costs and assigned that way.

Mr. Cohen continued asking about those cost centers in which a high percentage of costs were for contractors or consultants. If the proportion of contract costs to labor were high, it would be better to look at assigning the costs of contracts specifically rather than use labor cost ratios.

Mr. Cohen asked some question concerning specific line items in the CAM. He also asked if the Barkovich & Yap and the ISO would be updating the cost assignments or if they were fixed for the fall filing. The ISO responded that managers and directors would be re-interviewed and the cost assignments examined prior to the filing. Also, there should be more detailed information available about how the telecommunications system was being utilized.

Mr. Cohen asked about the level of detail in the Budget Tool. The ISO responded that the Budget Tool would still contain detailed account information and that an example of the Budget Tool output had been presented at the February 19th GMC meeting.

The discussion next turned to the functional association of charge types (Document 3). Ms. Yap briefly explained the method used to determine the associations of charge types with related services. CDWR asked if these charge types could be assigned to specific SCs. Ms. Yap pointed out that there was a difference between association and allocation and that the functionalization was correct, but recovery solely from a charge on SCs probably was not feasible.

Dale Yakin asked if depreciation was accounted for in these calculations. The ISO pointed out that the ISO is a non-profit entity for which depreciation was not a

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component of the revenue requirement. Capital assets were either purchased outright or purchased using bond financing. To the extent bond financing were used, debt service attributable to those assets was recovered. If the asset were purchased with cash, that expenditure was directly recoverable. The ISO did keep records of depreciation for accounting purposes, but not for rate recovery.

Mr. Cohen asked some questions about the charge type data used by Barkovich & Yap in their functional association. He asked why there was no association of Settlements, Metering and Client Relations costs to Forward Scheduling. The ISO responded that since both Core Reliability and Forward Scheduling were new charges that would cause adverse bill impacts, adding to those costs were increase the adverse bill impacts. Mr. Cohen asked what percentage of schedules were inter-SC trades. The answer was about 50 percent.

CDWR asked why all Ancillary Services related charge types were not associated with Market Usage. Barbara Barkovich and Ms. Yap explained that providing Ancillary Services was a Control Area operator function and that the method of providing Ancillary Services was through the market. The market was only the means through which the ISO procured reserves.

Mr. Cohen asked about the split of Energy and Transmission Services costs to load (80%) and to deviations (20%). Ms. Yap described this as an arbitrary decision. Mr. Cohen asked why it was necessary to have net uninstructed deviations as a second billing determinant. The ISO described this as a way of addressing the MID argument that one of the ISO's functions was resolving imbalances. Mr. Cohen argued that a second billing determinant was not needed because it did not add to understandability and simplicity. He did add that if the ISO was going to retain deviations as a billing determinant, it would develop a formula for dividing costs between the two billing determinants.

Mr. Cohen asked how the proposed congestion management was different from the current congestion management function. The ISO replied that the functionalization had moved some grid operations activities to Reliability Services and all Settlements costs to Settlements, Metering and Client Relations.

A question was asked about the billing determinant for the load portion of ETS. According to the ISO, the new billing determinant, Controlled Grid Load plus exports, would be about 239 million MWhs, down slightly from 242 million MWhs for net control area load plus exports.

CDWR asked why more costs were assigned to Core Reliability than Energy and Transmission Services. (Document 4) The ISO replied that the bulk of reliability costs were assigned to CRS according to the managers and directors judgment. In addition, a large percentage of systems application costs were included in CRS because the primary cost of these systems was in their initial development. The cost of scaling the system applications was very small.

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Mr. Cohen asked some questions on specific line items concerning the assignment methods. (Documents 5 and 6) He asked why the ISO should assign costs for systems no longer used, like the old EMS. Ms. Barkovich replied that the correct method is to assign costs for those systems as if it were still functional. Mr. Cohen asked if it would be possible to assess a stranded cost charge. This started a short discussion of the merits and possibility that the ISO actually could charge for stranded costs.

This discussion closed out the meeting as it was after 4:00 and the type size on the printout of the final document (Document 7) was too small for Mr. Cohen to read.

California ISO
2004 GMC Rate Structure Project
Contact List for July 7, 2003 conference call

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CAISO

LSUPDT: 08/05/03

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Status Report: Grid Management Charge

**Market Issues Forum
July 16, 2003**

**Ben Arikawa
Senior Financial Analyst**

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CALIFORNIA ISO Topics

California Independent
System Operator

- GMC Rate Structure Project
- Timeline

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2004 GMC Rate Structure Project

- ISO committed to GMC redesign in 2001 GMC proceeding (ER01-313-000)
- Among the issues addressed
 - Ratemaking principles
 - ISO/FERC accounting
 - Formula rate standard
 - Alternative rate proposals
- Goal to develop new GMC rate structure for 2004



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2004 GMC Rate Structure Project

(cont.)

- GMC web pages accessible from:

<http://www.caiso.com/docs/2002/08/02/2002080216283419989.html>

- Public documents
- Confidential documents (availability subject to execution of confidentiality agreement)



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Timeline

- Recent participant meeting/conference call
 - June 30 meeting
 - July 7 conference call
- Previous Board discussions
 - June 6, 2003
 - June 26, 2003



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Timeline (cont.)

- Upcoming Board discussions
 - July 17 Finance Committee meeting
 - Discussion of process
 - Discussion of proposals
 - Public comment
 - July 24 ISO Board meeting

SDG&E WHITE PAPER - 2004 GMC PROPOSAL
Applicability to APS and IID ownership shares of the Southwest Powerlink

San Diego Gas & Electric ("SDG&E") submits this white paper to the California Independent System Operator ("ISO") and Grid Management Charge "GMC") Stakeholder participants for their consideration. This paper sets forth SDG&E's concerns with the ISO's 2004 GMC proposal as applied to energy schedules of Arizona Public Service ("APS") and Imperial Irrigation District ("IID") on their respective ownership shares of the Southwest Powerlink ("SWPL").

Assumptions and Conclusions

As a preliminary matter, SDG&E maintains that the ISO should not bill SDG&E for, nor otherwise apply, *any* of the seven GMC "buckets" to the subject APS and IID service, because the APS and IID portions of SWPL have not been turned over to ISO Operational Control, and because applying GMC to such schedules violates the ISO Tariff, FERC precedent, and principles of reciprocity that have long governed relationships among control areas in the WECC. The SDG&E and ISO contentions in this regard are in litigation before the FERC, and therefore should be known to all the stakeholders, so we will not repeat them here. This paper assumes that the ISO will maintain its position for 2004 that it can properly apply GMC to the non-ISO participant SWPL shares. Given this assumption, this paper examines whether specific portions of the 2004 GMC proposal should otherwise apply to the subject schedules.

In sum, we conclude the billing determinants the ISO proposal uses to derive the unbundled rates for each of the buckets are overstated as a result of inappropriate inclusion of the APS/IID schedules in the billing determinants. Due to this overstatement of billing determinants, the ISO's unbundled GMC rates for each bucket are understated.

SWPL Background

In 1983 SDG&E completed construction of SWPL, a 292 mile 500 kV transmission line from its Miguel substation to the Palo Verde switchyard in Arizona. Pursuant to contracts executed in 1981 and 1983 ("Participation Agreements"), SDG&E transferred portions of SWPL to APS and IID. As a result, the Palo Verde – North Gila segment of SWPL is owned jointly by SDG&E, APS and IID in the ratio of 76.22%, 11% and 12.78%, respectively. APS and IID each operate and control their own portions of SWPL. APS uses its portion of SWPL to deliver energy to its retail load at APS's North Gila substation in Arizona. IID uses its portion of SWPL to deliver energy to its retail load in the Imperial Valley at the Imperial Valley substation (IID also owns a portion of the North Gila – Imperial Valley segment of SWPL). APS and IID are fully-resourced utilities that operate their own control areas, and secure their own reserves and ancillary services. Their retail loads lie within their respective control areas; put conversely, the APS and IID loads lie *outside* the ISO control area.

In addition, the Participation Agreements oblige APS and IID to reimburse SDG&E for line losses on their respective shares of SWPL by returning energy in kind based on an algorithm derived from actual measured flows. Under the Participation Agreements, SDG&E is the “Scheduling Agent,” and is thereby obliged to give effect to SWPL schedules submitted to it by APS and IID. After the ISO began operation, SDG&E was obliged to give effect to the APS and IID schedules by acting as the “middleman” and handing off the APS and IID schedules to the ISO. But the ISO cannot direct APS and IID as to the quantity, source or duration of any energy each may schedule on its respective share of the line. Nor does the ISO list the APS and IID SWPL shares as “ATC” on the ISO OASIS; such shares are not treated by the ISO as available to ISO customers and market participants. Third-party use of such shares must be arranged with APS and IID.

APS and IID Schedules Are Not “Exports”

One basis under which the ISO proposes to assess GMC on these schedules is that these schedules constitute “exports” from the ISO control area. But the APS and IID schedules do not contribute to the ISO Load responsibilities or to the ISO Control Area responsibilities. These schedules therefore do not cause the ISO to incur additional costs, and should not give rise to GMC.

The proposed billing determinants include Load and Exports (“Export” is not currently defined in the ISO Tariff). In this context, any Net Export when added to the ISO’s Load appears to be a net load served by the ISO. The ISO explains that one reason that Loads and Exports are charged the GMC is they are the “responsibility” of the ISO, as Control Area operator. The ISO describes the Control Area responsibilities that it fulfills for all loads within its Control Area that are considered part of its “Load Responsibility.” That justification simply does not apply to the APS and IID schedules on SWPL. The many load-related services described by the ISO are not services provided to the APS and IID schedules on SWPL because the APS and IID schedules on SWPL are not part of the ISO’s Load Responsibility (the ISO Tariff defines Load as “an end use device of an End Use Customer that consumes power” – a definition that cannot be stretched to APS and IID load by the mere fact that SWPL itself is in the ISO control area). Because APS and IID are fully-resourced utilities securing all energy reserves and other ancillary services to serve their respective loads in their separate control areas, APS and IID schedules on SWPL are the Load Responsibility of APS and IID, not the ISO. Since the generation serving the APS and IID loads are external to the ISO, every “export” from the ISO Control Area on SWPL is matched by a corresponding import, thus the Net Export associated with the APS and IID schedules is zero (exclusive of transmission system losses, which are the subject of a separate dispute).

Moreover, under the WECC’s Minimum Operating Reliability Criteria (“MORC”), a Control Area operator is required to carry operating reserves for its “Load Responsibility.” APS and IID schedules on SWPL, however, do not contribute to the Load Responsibility of the ISO Control Area because this energy is APS and IID’s Load

Responsibility as Control Area operators. Thus APS and IID as operators of separate Control Areas must provide the spinning reserves required to support their schedules on SWPL. And in fact APS and IID, and not the ISO, provide such spinning reserves.

In contrast, energy typically exported outside of the ISO Control Area is considered part of the ISO's Load Responsibility. For example, a Wheeling Out export from generation originating within the ISO Control Area to another Control Area would contribute to the Load Responsibility of the ISO, and as such would add to the Operating Reserves that the ISO would have to secure in order to "back-up" that export so as to maintain WSCC MORC requirements.

APS and IID retail customers do not benefit from ISO GMC services

Even if SWPL Energy (the APS and IID schedules to their respective loads) requires the ISO to perform some minor work, this incidental effort attendant to APS and IID schedules on SWPL does not justify imposition of the ISO GMC. Each and every Control Area operator in the WSCC must perform the same functions that comprise the ISO's Control Area Services. Coordination among Control Areas falls within the WECC reciprocity requirements. ISO coordination of the APS and IID schedules is no different than the coordination of ISO energy scheduled by APS and IID within their respective Control Areas. If, for example, when the ISO schedules on the Four Corners – Moenkopi Line, which is under the ISO's Operational Control in APS's Control Area, APS will be responsible for scheduling coordination and control area integration service of the sort the ISO characterizes as control area services. But APS does not charge the ISO for those services.

As recognized by the WECC requirements, such coordination is inherent in the interconnected operation of Control Areas. Due to the reciprocal nature of the duty, it is inappropriate for one operator to unilaterally assess such charges based solely on interconnected operation with another control area.

Evaluation of the ISO's proposed Billing Determinants as applied to APS and IID SWPL shares

We set forth below the ISO's proposed Rates and billing determinants as defined by the ISO's document dated 4/25/03, and summarize the applicability to the subject SWPL schedules:

1. Core reliability
 - a. Determinant = Gross non-coincident peak demand MW (Load + Export)
 - b. The APS and IID schedules to their respective loads are not part of the ISO's load responsibility. Further, since the Net Export is zero for the APS and IID schedules to their respective loads (each such export has a corresponding import, for a net zero Export), the APS and IID schedules

(exclusive of transmission system losses) have no effect on the ISO's Gross non-coincident peak demand.

2. Energy & Transmission Services – Load
 - a. Determinant = Net Control Area Load (Controlled Grid Load) + (Export)
 - b. The APS and IID schedules to their respective loads are not part of the ISO's load responsibility. Further, since the Net Export is zero for the APS and IID schedules to their respective loads (each such export has a corresponding import, for a net zero Export), the APS and IID schedules (exclusive of transmission system losses) have no effect on the ISO's Net Control Area Load.
3. Energy & Transmission Services – Deviation
 - a. Determinant = Absolute value of net uninstructed deviations by settlement interval (MWh)
 - b. Aside from the ongoing dispute regarding transmission losses associated with the APS and IID schedules, at a minimum the ISO should credit SDG&E's self-provision of losses for APS and IID. We believe this is the intent of the ISO's proposal, based on the ISO answer to SDG&E's complaint in Docket NO. EL03-131-000.
4. Scheduling
 - a. Determinant = Number of Final Hour-Ahead schedules returned by Scheduling Infrastructure
 - b. Scheduling should be excluded on the principle of reciprocity (the ISO is not charged by other Control Areas for schedules on transmission under the ISO's Operational Control in those other Control Areas).
5. Congestion Management
 - a. Determinant = Hour-ahead net inter-zonal New Firm Use flow (excludes ETCs)
 - b. The ISO does not perform services in this category for the APS and IID schedules.
6. Market Usage
 - a. Determinant = Purchases and sales of Ancillary Services, instructed energy, and absolute value of net uninstructed deviations
 - b. The ISO does not perform services in this category for the APS and IID schedules (there is no market participation involved; rather, APS and IID serve their own loads with generation sources of their own choosing exclusive of the ISO).
7. Customer Service
 - a. Determinant = Min \$500/month fixed charge + \$.0289

- b. We are unaware of any "Customer Service" provided by the ISO to APS or IID in connection with their schedules.

Therefore the ISO 2004 GMC billing determinants should be revised accordingly.

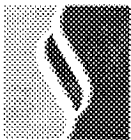
Rate Impact of GMC on APS and IID SWPL schedules

The total amount of GMC charges associated with the APS and IID schedules currently is about \$2.17 million annually; based on the ISO's new 2004 GMC projection, GMC charges will be reduced to \$1.3 million annually.

ISO Current GMC	Current CAS	Current CONG	Current ASREO					Total
APS/IID Annual Billing Determinants	1,939,397	21,082	1,118,624					
APS/IID Annual Charges	\$ 1,062,572	\$ 6,570	\$ 1,104,139					\$2,173,281
ISO Proposed 2004 GMC	Core Reliability Services	Energy & Transmission Services Load	Energy & Transmission Services Deviation	Forward Scheduling	Congestion Management	Market Usage	Settlements, Metering and Client Relations	
APS/IID Annual Billing Determinants	4,263	1,939,397	34,121	48,098	21,082	34,121	12	
APS/IID Annual Charges	\$ 746,723	\$ 423,633	\$ 27,542	\$ 74,407	\$ 3,454	\$ 32,570	\$ 6,000	\$1,314,328

Conclusion

In summary, for the reasons given above, the ISO's proposed 2004 GMC rates are incorrect due to the use of the incorrect billing determinants being used to derive the unbundled GMC rates.



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2004 GMC Rate Structure Evaluation

**July 17, 2003
Finance Committee**

**Presented by:
Phil Leiber, Treasurer and Director of Financial Planning**

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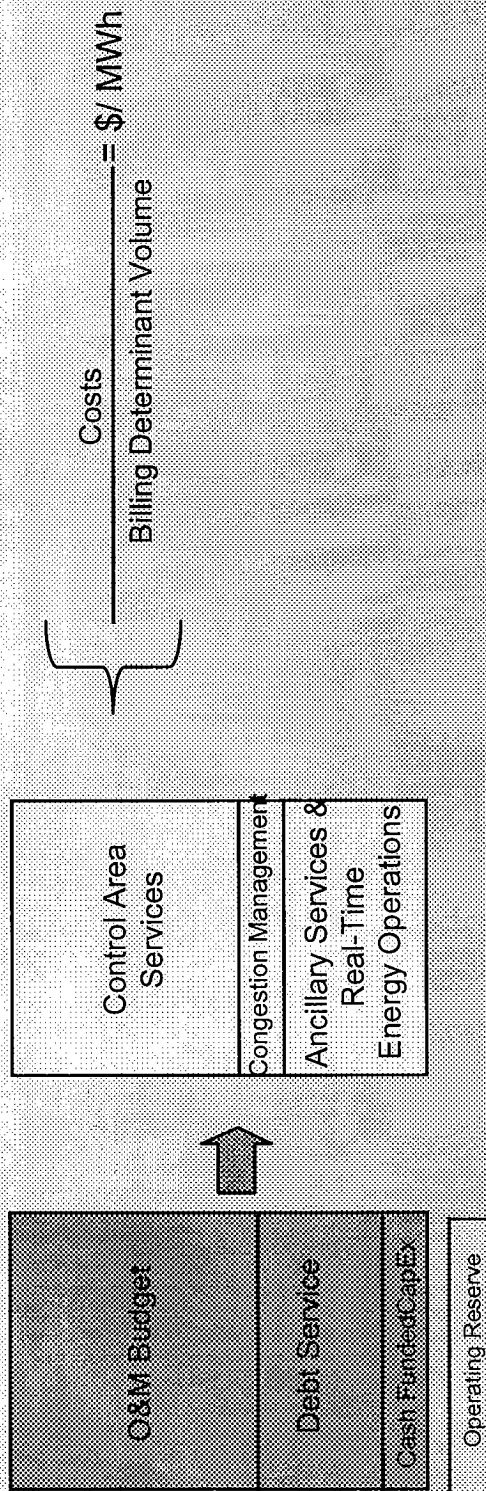
Agenda

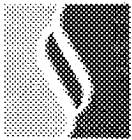
- Overview of 2004 GMC Rate 10 minutes
- Structure Review Process
- Proposals 75 minutes
- Comparing the Proposals 10 minutes
- Public Comments 30 minutes
- Board Discussion 10 minutes



GMC Rates Overview

Total ISO Costs or
"Revenue Requirement" Costs of ISO Services Unbundled Rates (for each service)





Background

- History
 - Bundled GMC through 2000
 - Unbundled GMC in 2001
- Continued unbundling
 - Impetus from external and other factors
 - 2001 GMC Rate Case
 - Continued changes in Energy Markets
 - Evolving process



Four Step Rate Structure Development Process

- I. Define the ISO's services
- II. Assign the ISO's costs to such services
- III. Develop a method of cost recovery
- IV. Consider mitigation of bill impacts



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Results of Rate Structure Development Process

- Three Full Proposals Developed:
 - ISO
 - Modesto Irrigation District
 - Southern California Edison
- Modifications requested by some

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GMC Rate Structure Project Objectives

Substantive

- Meets FERC “just and reasonable” standard & appropriately allocates costs;
- Based on cost causation;
- Easy to administer (including cost effective) and understandable;
- No unmanageable adverse operational impacts;
- Recovers ISO costs in a stable, low risk manner without excess volatility;

Procedural

- Results from open and balanced stakeholder process;
- Filed by deadline;
- Meets terms of the 2002 GMC Settlement Agreement.



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Proposal Presentations

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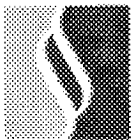
Comparing the Proposals- Similarities

Attribute	ISO	SCE	MID
Provide for full recovery of ISO revenue requirement	Yes	Yes	Yes
Similarity in Functions			
Further unbundling of CAS & category based on grid usage	Yes	Yes	Yes
Markets charge	Yes	Yes	Yes
Use of uninstructed deviations as billing determinant for a reliability based charge	Yes	Yes	Yes
Customer Impacts: Cost shifts from changing existing structure	Yes	Yes	Yes



Comparing the Proposals- Differences

Attribute	ISO	SCE	MID
Number of functions	6 categories	5 categories	3 categories
Billing Determinants			
Assess charges for control area load other than for use of ISO controlled grid	Yes	Yes (muni)/ No (QF)	No
Degree of reliance on deviations	Lower	Medium	Higher
Use of non-volumetric measures	Yes	No	Yes
Demand Charge	Yes	No	Yes
Multi-part billing determinants?	Yes	No	Yes
Tiered charges?	No	Yes	No



Summary

- The proposals
 - Incorporate different philosophies
 - Functions
 - Who pays & basis for payment
 - Address different concerns
- Results of polling
- Which proposal will provide for “just and reasonable” rates and meet the project objectives?



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Public Comments

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Discussion by Finance Committee

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Next Steps

- Executive Session
 - Legal strategy / issues
- July 24
 - Finance Committee
 - Public comments
 - Recommendation of proposed GMC structure
 - Board Meeting
 - Approval of recommended GMC structure



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Memorandum

To: ISO Finance Committee

Attachments

From: William J. Regan, Jr., Chief Financial Officer
Deborah Le Vine, Director of Contracts
Philip Leiber, Treasurer & Director of Financial Planning
Ben Arikawa, Senior Financial Analyst

CC: Board of Governors
Board Assistant, ISO Officers

Date: July 9, 2003

Re: **Grid Management Charge- 2004 Rate Structure**

This memorandum is for information only.

EXECUTIVE SUMMARY

In the 2001 Grid Management Charge ("GMC") rate case (ER01-313-000), the ISO was directed by the FERC administrative law judge ("ALJ") to undertake a comprehensive review of the GMC rate structure. The ISO commenced a stakeholder process for that purpose in August 2002. Since last August, stakeholder participants and ISO staff worked cooperatively developing a charter (see **Appendix 1**) setting forth the objectives of the project, discussing and attempting to resolve rate design and other related issues, and reviewing analytical details of alternative proposals.

The ISO provided stakeholder participants with the materials and information to develop their own rate proposals (as mandated by the 2001 ALJ Initial Decision). The Modesto Irrigation District ("MID"), Southern California Edison ("SCE"), and the ISO staff developed full proposals which the ISO and participants reviewed over the past several months. Indicative rates and customer impact studies have been developed and distributed to and reviewed by participants. While there are a number of similarities among the proposals and a convergence of views on many issues, there are also notable differences between them.

The GMC rate structure is an integral part of the ISO's GMC rate-setting process, which will culminate in an October 31 FERC filing setting forth the ISO's requested rates for 2004. As discussed at the June 26 presentation on the budget timeline, the ISO establishes 2004 goals, then develops a revenue requirement through the budgeting process that reflects the priorities of the goals. The revenue requirement is then processed through the GMC rate structure to determine the GMC rates. The ISO initiated its 2004 budget process on July 1. A preliminary review of the budget is scheduled for the September Board meeting. The rate

structure needs to be determined prior to mid-August to provide time to apportion the ISO's costs to the new GMC service categories and to develop preliminary rates for publication with the proposed budgets in September. Board approval of the budget and the resulting GMC rates is necessary in October. In late October, the ISO will file with FERC a Section 205¹ rate case proposing new rates to be effective January 1, 2004. FERC cost-based ratemaking allows the ISO's operating, capital and start-up costs to be recovered through the GMC rates. The ISO's filing will trigger a series of events likely to include any or all of the following elements: settlement discussions, discovery, testimony, a hearing, an ALJ initial decision, and ultimately a FERC decision.

BACKGROUND

A brief overview of the history of the GMC by year follows in this section.

1998-2000

In its first rate filing for the first year of the ISO's operations in 1998, the ISO proposed that all load within the control area should pay the ISO's GMC, which covered the ISO's operating, capital and startup costs. Certain parties, mainly those with existing contracts, argued they should pay only for the ISO services that they used, or some other reduced rate. Shortly after the filing, the ISO reached a settlement with all paying parties that provided a discount of 50% to 100% for transmission volumes for entities with existing transmission contracts. At the same time, the ISO agreed to undertake a study of how its GMC might be recovered on an "unbundled" basis, i.e. with separate charges for its various services. The ISO retained consultants to conduct a study during 1998 on this matter. However, there was little support for the study's recommendations, and the 1998 GMC settlement was extended until December 2000.

2001

During 1999-2000, the ISO conducted a stakeholder process that led to the ISO's first unbundled GMC, effective January 2001. The unbundled GMC consisted of three separate charges, assessed on various billing determinants. That GMC structure, summarized in the following table, with some minor modifications, continues to be in effect².

¹ Section 205 of the Federal Power Act governs the establishment of public utility tariffs and rates. Rate changes are not permitted unless a new rate schedule has been filed; Section 35 of the Federal Power Act specifies the contents of the rate schedules.

² FERC Order 436 issued on May 2, 2003 on the 2001GMC rate case may provide for retroactive changes to the existing GMC structure with respect to Control Area Service (CAS) assessed to "behind the meter load". The ISO has sought clarification of certain elements and rehearing of other elements of this order.

TABLE 1: Overview of Current Unbundled GMC Structure

<u>GMC Category</u>	<u>Billing Determinant</u>
1. Control Area Services (CAS)	Volumetric: Gross Load and Exports in MWh
2. Interzonal Scheduled Load subsequently renamed "Congestion Management" (CONG) in 2002.	Volumetric: Net HA Scheduled interzonal power flows per path in MWh
3. Market Operations, renamed Ancillary Services and Real Time Energy Operations. (ASREO) in 2002.	Volumetric: Purchases and Sales of Ancillary Services, Real Time Energy (instructed and uninstructed) in MWh

The ISO filed this rate with FERC in November 2000. It was set for hearing in 2001. The FERC ALJ issued her Initial Decision on the 2001 rate case in May 2002. The Initial Decision largely affirmed the ISO's unbundled GMC.

In the 2001 ALJ's Initial Decision, the judge largely rejected parties' requests to unbundle beyond the three buckets, or to reexamine the application of the three buckets to such parties. Instead, she directed the ISO to undertake a comprehensive stakeholder process to explore alternatives to the current three-bucket structure, which could result in a new structure for 2004. In addition, she specifically directed the ISO to explore further certain issues raised in the 2001 case (See: Direction from the Initial Decision, p. 4).

FERC issued its order on the 2001 rate case in May 2003. The order largely affirmed the Initial Decision, except for requiring an alternative method of determining the Control Area Services charge for certain behind the meter (municipal and QF) load. The ISO and other parties filed motions for clarification and rehearing in June 2003 due to ambiguities and other issues in the decision.

2002-2003

In November 2001 the ISO made a Section 205 rate case filing for the year 2002 that proposed certain modifications to the 'three-bucket' GMC structure established in 2001. The 2002 rate case was settled in November 2002 by direct negotiation with intervening parties. The ISO and intervenors agreed to keep the three-bucket GMC structure in place, essentially as filed in 2001, through 2003. As a term of the settlement of these cases, the ISO also agreed to explore certain additional issues in the GMC rate structure review process ordered by the ALJ in the 2001 case.

OVERVIEW OF THE GMC RATE STRUCTURE REVIEW PROCESS

The ISO commenced a comprehensive review of a potential new GMC structure for 2004 in August 2002. The "2004 GMC Rate Structure Project" has consisted of both an internal process for the ISO to develop a new 2004 GMC rate structure, and an external stakeholder process. The internal and external processes were linked at each stage of the rate structure development process.

Direction from the Initial Decision

The Initial Decision in the 2001 GMC rate case directed the ISO to develop the basis for a revised rate structure effective January 1, 2004 through a comprehensive stakeholder process. In the stakeholder process the ISO was to “make every effort...to encourage and facilitate meaningful involvement and input from all affected parties.”

The Initial Decision also required examination of specific topics raised in the 2001 rate case including the MID proposal for redesign of “Control Area Services”, the CPUC/EOB proposal to assess demand charges, and any others brought forward by stakeholders. Additionally, the ISO was to review cost allocations, consider increased granularity of “Control Area Services”, and perform, or provide data for MID to perform, a cost study for its proposal for the ISO’s GMC. The settlement of the 2002 GMC rate case also obligated the ISO to address these and other topics in the 2004 GMC Rate Structure Project.

Stakeholder Process Format and Communications

In July 2002, the ISO proposed two alternate formats for the stakeholder process, one that would have established a committee with representatives from each stakeholder class (to assure a balance of views on the issue), or an open format where any interested party could contribute as desired to the process. Stakeholders expressed a preference for the second option, and that approach has been followed.

The ISO was encouraged in the Initial Decision to involve stakeholders comprehensively in the process. Numerous and innovative means of communications have been used, including emails (with hundreds of group and individual emails), teleconferences, meetings at the ISO and at stakeholder locations. The ISO solicited the participation of parties through numerous announcements about status of the project during and after its start, and created a readily accessible record of the project for parties, through a project website. A project website discussion board allowed for a written dialogue with and between stakeholders on the issues under study of the group. In addition to the open sessions and information distributions, confidential materials were distributed and discussed with individuals who signed the ISO’s non-disclosure agreement and confidentiality agreements. These restrictions have been put in place primarily to protect scheduling coordinator specific information that was reviewed in such meetings, but also to control and protect the use of information that may be used in the 2004 GMC rate case or in other forums.

The ISO also committed resources specifically to involve participants and aid their fact finding or alternate rate development through one-on-one meetings, telephone calls and conferences and data responses. ISO staff additionally provided briefings on the status of the project at Market Issues Forums approximately on a bimonthly basis, and invited additional participation there.

Objectives of the GMC Rate Structure Project and the Stakeholder Process

The objectives, as well as the benefits, scope, constraints, deliverables, and risks are discussed the “2004 GMC Rate Structure Project Charter”, at **Appendix 1**. The document also contained a high-level timeline of the steps to be accomplished in each month of the

project, culminating in a October 2003 FERC filing (60 days prior to the effectiveness of the new rates on January 1, 2004). The most important element of this document is the project goals section, which lists the desired outcomes of the project by the ISO and stakeholders. The project goals can be used as one basis by which to assess the merits of each proposal.

Participants in the Stakeholder Process

Some twenty different entities have participated in the stakeholder meetings including representatives of Qualifying Facilities (QFs), Governmental / Municipal Utilities, state and federal regulators, Investor Owned Utilities, and generators/marketers. **Appendix 2** contains a listing of participants.

ISO Internal Process

ISO staff also coordinated the stakeholder process with the development of the ISO's 2004 GMC Rate Structure proposal. Barkovitch & Yap were the ISO's rate design consultants and their extensive expertise was instrumental in the development of the ISO rate proposal. An inter-department project team provides the internal leadership and continues to meet weekly as it has since December 2002. Representatives from the ISO's Department of Market Analysis have also reviewed and commented on the ISO's rate proposal and those of MID and SCE.

Results

The ISO has received positive feedback on the conduct of the stakeholder process from numerous parties. The GMC Rate Structure review process has resulted in three fully developed proposals by the California ISO, Modesto Irrigation District, and Southern California Edison. These proposals and the existing GMC structure are summarized in **Appendix 3**. Comprehensive descriptions of each proposal (prepared by each party) are provided at **Appendices 4, 5 and 6**. In addition to these fully developed proposals, other parties have recommended modifications to the ISO's proposal. These include:

Party	Recommendation
California Department of Water Resources	Replace the billing determinant for the ISO's Core Reliability Services category (<u>non-coincident</u> peak demand by month by SC) with monthly <u>coincident</u> peak demand.
San Diego Gas & Electric (SDG&E)	Exempt from the GMC exports to Arizona Public Service (APS) and Imperial Irrigation District (IID) on the Southwest Powerlink (SWPL) transmission line. SDG&E intends to present this issue to the Finance Committee for consideration on July 17. (See Appendix 9 .)
Southern California Edison	SCE has offered to withdraw its 2004 GMC proposal in exchange for a reduced GMC charge for dynamically dispatched exports on the Mohave transmission line. SCE's terms for this offer are attached at Appendix 6 .

RATE STRUCTURE DEVELOPMENT PROCESS AND PRINCIPLES

This section discusses the development steps in the rate structure and rate design process, and addresses key principles in each step:

1. Define ISO services
2. Assign ISO costs to such services
3. Recover costs for each service.
 - a. Who should pay?
 - b. On what basis should the charges be assessed?
 - c. Are the billing determinants stable and predictable in advance?
4. Consider cost shifts and the potential need to mitigate such shifts.
5. Assess the merits of competing GMC rate structure proposals

This section addresses any changes in principles used to justify a departure from the current three service category GMC structure.

Define ISO Services

Defining ISO services is necessary in the “functionalization” process, where the ISO’s various costs are aggregated into service categories these costs support. Although there are some similarities, each proposal has defined or delineated ISO services differently.

During the GMC review which resulted in our current unbundled GMC structure, five services of the ISO were initially defined: (1) Control Area Services, (2) Scheduling, (3) Congestion Management, (4) Market Operations, and (5) Settlements, Metering & Billing. These represented significant, separately identifiable functions contributing to the ISO’s overall mission as manager of the transmission grid. Ultimately, these five functions were collapsed into three: Control Area Services and Scheduling shared a common billing determinant, as did Market Operations and Settlements, Metering & Billing.

In this current GMC review process, the ISO’s proposal again employed these five previously identified functions, with the further unbundling of Control Area Services into two parts: Core Reliability Services and Energy & Transmission Services. This change was made in response to directives from ALJ in the 2001 GMC rate case Initial Decision, and feedback from stakeholders in this process.

Modesto Irrigation District arrives at a different “functionalization” of ISO services, as does SCE in their proposal. The basis for their functionalization results is described in their proposals at **Appendix 5 and 6**.

Assign ISO Costs to Services

Each of the three rate proposals used components of the ISO’s 2003 revenue requirement, as set forth in the November 2002 FERC filing, and assigned or allocated those costs to the ISO functions defined in their proposals. With the assistance of Barkovich & Yap, the ISO team based its cost assignment/allocation process on lengthy interviews with department managers and detailed explanations of the proposed service categories. This

process was similar to that used to arrive at the current GMC structure, and relied on the same principles.

The ISO provided resources to assist MID and SCE in the assignment of ISO costs to the service categories they defined in their proposals as well as extensive data and documentation to both MID and SCE. Numerous telephone conferences were held to develop and finalize the allocation percentages used in their proposals. ISO managers and directors were also made available to facilitate the development of these alternative proposals.

Recover Costs for Each Service

This step of the rate structure process involves selecting "billing determinants" through which the costs of each service category are recovered. Issues considered in this step include:

a. Who should pay?

Once functions are defined and ISO costs assigned to those functions, the users of those services should pay for them in accordance with the principle of "cost causation". This was the same basic principle applied to arrive at the current GMC structure. Changes between the current GMC structure and the proposed structure are the result of differences in service categories, additional insight into cost causation, and the results of the 2001 rate case.

b. On what basis should the charges be assessed?

There are various ways to recover costs from the users of a service. Some important alternatives include recovery based on volume (in MWh), demand (in MW), transactions, or charges per customer.

For example, the users of the service "Forward Scheduling" in the ISO Proposal could be assessed charges based on the number of schedules (a transactional charge), or on the energy volumes contained on those schedules (a volumetric charge). Ideally, the method selected should reflect "cost causation"—finding a billing determinant that is correlated with the ISO's costs of processing schedules. For this service, the ISO's costs relate to number of schedules processed. In this instance, additional research into the most appropriate basis for assessing charges resulted in different results than in the 1999/2000 GMC review process. Then, the costs of Scheduling function were to be recovered on the basis of a fee per MWh of energy scheduled. Subsequent investigations showed that the costs of this function are more closely related to the number of schedules processed rather than the amount of energy on those schedules.

c. Are the billing determinants stable and predictable in advance?

For any billing determinant under consideration, two key attributes are stability and predictability. These are the same principles applied in the 1999/2000

GMC review process. As the ISO must recover its costs in a given year based on rates set in advance, a billing determinant that fluctuates significantly is less than ideal. Also, as the rates must be set in advance, a billing determinant that is not expected to change dramatically from historical levels is also preferred to one that may change due to market structure changes or other factors.

Some billing determinants in the 2004 proposals may be less stable or predictable than others. This issue is further discussed in **Appendix 7**. Appropriate measures can be applied to reduce the risk associated with this issue, including having the ability to adjust rates on a quarterly basis (as provided for in the current ISO Tariff).

Consider Cost Shifts and the Potential Need to Mitigate Such Shifts

As discussed below, various analyses were performed on each proposal to determine the extent to which individual scheduling coordinators would pay significantly more or less than under the current GMC structure. While such cost shifts may be warranted based on the principles of cost causation, significant shifts may be inappropriate or unacceptable for other reasons, including equity, the impact on smaller customers, and the potential need to phase-in large changes over time.

In both the ISO and MID proposals, substantive modifications were made during the course of the stakeholder process to address significant cost shifts by changing proposed billing determinants. No changes to billing determinants were made to the SCE proposal since its introduction in February 2003. An example of the resolution of a cost-mitigation issue is provided in the following text-box:

Mitigating the Effect of a Service Category in the ISO's Proposal.

The original intent of the ISO in developing the "Settlements, Metering & Client Relations" charge was to assess these costs on a per customer-month basis, as all customers are viewed as users of these services. However, this could have resulted in a per customer charge of nearly \$55,000 per month. This was not viable, as it would be more than smaller and medium SCs could bear. Various alternative approaches were explored, but it was decided that a large portion (in excess of 98%) of the costs associated with the "Settlements, Metering & Client Relations" category should be recovered through the billing determinants of other functions, thereby mitigating the adverse billing impact of this service category. This is not a re-functionalization, but rather a mitigation measure.

Assess the Merits of Competing GMC Rate Structure Proposals

Three parties have developed different proposals for the ISO's 2004 GMC structure. These proposals differ in elements such as the services offered by the ISO and who should pay for those services. Selecting an optimal proposal from among these three involves weighing the relative merits and shortcomings of each. The 2004 GMC Rate Structure project charter (**Appendix 1**) sets forth several objectives for the project and the resulting new GMC rate structure, and these objectives provide one means by which to assess each of the proposals. **Appendix 8** contains a commentary prepared by ISO staff on this topic.

SIMILARITIES AND DIFFERENCES OF THE PROPOSALS

The three proposals were developed in a stakeholder process where parties held a dialogue on numerous issues. In this process, there was widespread support for certain ideas, and limited support for others. As a result, the proposals have some similarities and notable differences.

Similarities

TABLE 3: SIMILARITIES OF THE THREE PROPOSALS

Attribute	Proposal		
	ISO	SCE	MID
Provide for full recovery of ISO revenue requirement	Yes	Yes	Yes
Similarity in Functions			
Further unbundling of CAS & category based on use of grid.	Yes	Yes	Yes
Markets charge	Yes	Yes	Yes
Billing Determinants: Use of uninstructed deviations as BD for reliability based charge	Yes	Yes	Yes
Customer Impacts Cost shifts from changing existing structure	Yes	Yes	Yes

Recovery of the ISO Revenue Requirement. All of the proposals would provide for full recovery of the ISO's revenue requirement (operating & maintenance, capital and startup costs).

Similarity in Functions. While the ISO functions defined by each proposal differ:

- All provide for "unbundling" into various reliability and market-related functions, and some degree of further splitting of the existing Control Area Services category.
- All have a reliability-related service category that is assessed based on usage of the transmission grid.³
- All have a separate category for usage of the ISO's market function.⁴
- All have a reliability-related service category that uses uninstructed deviations (departures from scheduled energy volumes) as a billing determinant, recognizing that significant uninstructed deviations are to some extent a cost-driver for the ISO.⁵

Cost Shifts from Transition from Current to New GMC Structure. All three of the proposals result in cost shifts--some SCs would pay more, and some would pay less than under the current GMC structure. The extent of the cost shifts varies by proposal. See "Customer Impact Analysis", p.11.

³ In the ISO Proposal-"Energy & Transmission Services"; MID Proposal-"Managing Transmission Flows"; SCE Proposal: "Control Area Services".

⁴ In the ISO Proposal-"Market Usage"; MID Proposal- "Administering Markets"; SCE Proposal: "Market Operations Service".

⁵ In the ISO Proposal-"Energy & Transmission Services"; MID Proposal-"Resolving Energy Imbalances"; SCE Proposal: "Real Time Operation Services".

Differences

The table and subsequent discussion summarizes the major differences between the three proposals.

TABLE 3: DIFFERENCES AMONG THE THREE PROPOSALS

Attribute	Proposal		
	ISO	SCE	MID
Number of functions	6 categories	5 categories	3 categories
Billing Determinants			
Degree of reliance on deviations	Lower	Medium	Higher
Assess charges for control area load other than for use of ISO controlled grid	Yes	Yes (muni)/ No (QF)	No
Use of non-volumetric measures	Yes	No	Yes
Demand Charge	Yes	No	Yes
Use of multi-part billing determinants	Yes	No	Yes
Use of a fixed per SC charge	Yes	No	Yes
Use of tiered charges	No	No	Yes

Number of ISO Functions Defined. MID provides three, SCE defined five, while the ISO proposal contains six functions. All proposals do provide for further unbundling of the Control Area Services function, as directed by the 2001 rate case Initial Decision.

Billing Determinants-Degree to which ISO Costs are Associated with "Deviations". (differences between scheduled versus actual energy consumed or generated) The MID proposal has as a core principle that the ISO exists largely to manage transmission flows and resolve energy imbalances. It would associate a higher portion of the ISO's costs to the "resolving energy imbalances" function. While the ISO proposal includes some recovery of costs related to deviations (through the Energy & Transmission Services category), the ISO proposal does not reach the same conclusion. The SCE proposal's Real Time Operation Services category associates more ISO costs to uninstructed deviations than does the ISO's proposal, but less than MID's proposal.

Billing Determinants-Assessing GMC on Broad Measure of Load. The ISO Tariff requires entities to schedule all load and generation in the ISO Control Area. The ISO's GMC proposal would assess some GMC (the Core Reliability Service charge) to load within the Control Area but not using the ISO Controlled Grid. MID would assess GMC only for the use of the ISO Controlled Grid. SCE's proposal is "in between" the ISO and MID proposals. It would assess GMC for municipal utility load that does not use the ISO Controlled Grid, but not QF load. This issue has been a key point of contention since ISO's first GMC proposal for 1998, and was the central disputed point in the 2001 GMC rate case. FERC's recent order on the 2001 GMC case⁶ affirmed the ISO's position that "behind the meter" load should bear some responsibility for the ISO's costs. The order indicated that the basis for such charges should be a demand charge, and the ISO's 2004 proposal is consistent with this.

⁶ Opinion No. 463, "Opinion and Order on Initial Decision", (Docket ER01-313-000, etc.) 5/2/03. The ISO and other parties filed requests for clarification and rehearing in June 2003, due to ambiguities and other contentious points in the order.

Billing determinants-Other. The ISO's current GMC structure uses only volumetric (MWh) charges. Both the ISO's 2004 proposal and MID's proposal would use additional non-volumetric measures. SCE's proposal would continue to use only volumetric measures. In the stakeholder process, SCE has expressed opposition to the use of "demand" charges as are contained in both the ISO and MID proposals, but recognized that the May 2, 2003 FERC Order on the 2001 GMC case supported such charges. The movement away from strictly volumetric measures in the ISO and MID proposals is one reason for cost shifts between customers. The cost shifts under the "volumetric" based SCE proposal are smaller than for either the MID or ISO proposals, since the current ISO GMC is also recovered on a volumetric basis. Additionally, the ISO and MID proposals have service categories that have more than one billing determinant (and for MID, the use of tiered rates), while SCE's proposal does not.

CUSTOMER IMPACT ANALYSIS

Recovering the same total ISO revenue requirement using different service categories and billing determinants will result in some ISO Scheduling Coordinators paying more and some paying compared to the current GMC structure. This is the case for all three 2004 proposed GMC. These cost shifts may be appropriate to the extent that the new rate structure better reflects the important principle of cost causation. Parties may be paying less than an appropriate share of the ISO's costs under the current GMC structure. For example, parties that conduct inter-SC trades currently pay no GMC for such trades, but would pay under the ISO's proposed structure for 2004. There are ISO costs involved in administering such inter-SC trades. These parties would see a justified increase in their GMC bill.

While there are various ways to measure the extent of the cost shifts on an aggregate level, the most important measure for an individual participant is what they would pay under the proposed new GMC structure compared to the current approach. That was the primary analysis that was used to review each of the three proposals in the stakeholder process⁷. For each proposal, the pro-forma rates were applied to the historical usage patterns of scheduling coordinators from September 2001 – August 2002, and the results for each SC were made available to that SC, and the results for all SCs were released on a masked basis to those in the stakeholder process who signed a confidentiality agreement.

Information on this issue will be provided and discussed in the Finance Committee Executive Session on July 17.

POSITIONS OF THE PARTIES

Throughout the stakeholder process the ISO has requested feedback on the various proposals. Some parties have expressed their views while others have been less

⁷ Other analyses included developing (1) histograms showing the number of Scheduling Coordinators who would pay more or less by X%, or \$X, (2) classifying SCs into classes by size: small, medium and large and comparing GMC paid under the current approach versus the proposals for 2004, (3) providing data to the CPUC to evaluation changes by "customer type", which it defined as IOU, muni/governmental entity, QF, and "others".

forthcoming. The ISO will request formal feedback on the proposals during July, and to the extent we are provided with responses, report these to the Finance Committee on July 17.

OTHER CONSIDERATIONS

During the stakeholder process the possibility was raised of continuing the current GMC structure, at least until the uncertainty around the timing and ultimate composition of MD02 market structure changes was resolved. Ideally, a new rate structure would reflect the "end state" that would be achieved after all the contemplated phases of MD02 are implemented. The ISO's 2004 GMC proposal must reflect what is in place when the new rates go into effect. Changes will be required when locational marginal pricing is implemented.

While continuing with the status quo might be an attractive proposition, it would require unanimous agreement from parties, in some form of a settlement agreement. We have not received indications that support exists for this option and have not attempted to secure such an agreement. FERC's Order 463 on May 2, 2003 related to the 2001 GMC case also appeared to increase the probability that parties could potentially accept the current three-bucket GMC structure, albeit as modified by that Order. The Order indicated that behind-the-meter load should pay a lesser Control Area Services charge, a key contested point in the 2001 GMC case. However, parties view this order as vague and numerous requests for clarification and rehearing were submitted to FERC on June 2. FERC action on these requests is unlikely in the near future, and the outcome is uncertain in any event. As a result this FERC order is unlikely to bring parties closer to an agreement that the current GMC structure (as modified by the May 2 order) would be appropriate to extend through 2004.

NEXT STEPS

Significant steps related to the GMC Rate Structure include:

<u>Date</u>	<u>Action</u>	<u>Comments</u>
July 24	Finance Committee Recommendation on 2004 GMC Rate Structure Board Approval of 2004 GMC Rate Structure	July decision required to permit adequate time for preparation and publication of proposed 2004 rates.
October 23	Board Approval of 2004 Budget and GMC Rates	
October 31	Filing of Budget and GMC Rates with FERC	Requires 60 days between filing and effective date of new rates
January 1, 2004	New rate structure in effect	New rates likely to be accepted by FERC, subject to potential refund based on subsequent hearing (unless settlement agreement reached with intervenors).

Attachments

APPENDIX 1: 2004 GMC Rate Structure Project Charter

APPENDIX 2: Participants in Stakeholder Process

APPENDIX 3: Summary of Proposed Functionalizations and Comparison to Current GMC Structure

Rate Proposal Overviews for ISO, MID, SCE Proposals (providing indicative rates)

APPENDIX 4: ISO White paper on Proposed 2004 GMC Rate Structure

Functionalization of Activity Groups for Proposed ISO Rate Structure

Comparison of ISO Rate Structure Proposal to Rate Structures of other ISOs

APPENDIX 5: MID Proposal

APPENDIX 6: SCE Proposal

APPENDIX 7: Potentially Unstable Billing Determinants

APPENDIX 8: Commentary on Project Charter Objectives

APPENDIX 9: SDG&E White Paper – 2004 GMC Proposal

APPENDIX 1

PROJECT CHARTER

2004 GMC Rate Structure Project, a Stakeholder Process

Business Opportunity/Problem: [State the problem(s) the project will address in business terms. State the problem's impact to the business including the effects and costs (tangible, where possible)]

The California ISO ("ISO") needs to recover its start-up, capital, and operation and maintenance costs (collectively referred to as ISO costs or revenue requirement) through the Grid Management Charge ("GMC"). The ISO believes that a complete reassessment of the GMC Rate Structure¹ is warranted at this time given past experiences with GMC ratemaking, and anticipated future changes. The Initial Decision by the Federal Energy Regulatory Commission ("FERC") Administrative Law Judge in the 2001 GMC proceeding directed the ISO "to undertake a comprehensive stakeholder review for the purpose of re-evaluation of the GMC structure in 2003" and "the ISO is directed to make a Section 205 filing upon completion of that re-evaluation process in 2003."²

An added challenge is the fact that the ISO is making significant changes to the current market design over the period of the MD02 effort³ (potentially extending from 2002-2006). The existing GMC rate structure needs to be re-evaluated to address stakeholder concerns in preparation of the 2004 GMC Rate setting process in the fall of 2003. Significant challenges in evaluating appropriate changes will be the lack of clarity regarding timing and composition of the MD02⁴ and FERC Standard Market Design elements⁵, and lack of data related to the effect of these changes on potential billing determinant volumes and costs.. Parties recognize that future changes to the GMC may be appropriate outside the scope of this effort.

¹ Rate Structure includes: determination of services provided (current and future), accumulation of overall costs, cost allocation, rate design (including billing determinants). While not the primary focus of this group, the overall level of ISO costs (also referred to as the ISO revenue requirement) is of concern to ISO stakeholders, and consideration of a mechanism to adequately address this issue prospectively may be necessary.

² The intention of the direction is to work during 2003 for implementation of a new GMC structure in 2004.

³ MD02 is being funded through the currently existing rate structure/budgets.

⁴ Since the inception of this 2004 GMC Rate Structure Project, the timeline for MD02 has been delayed, with Phase II and III originally targeted for 2003, now scheduled for mid-2004. Given the uncertainty as to the ultimate composition and timing of specific elements of MD02, some participants in this process believe it may be prudent to limit major changes to the current GMC structure and to reconsider such changes in the future. However, as no consensus exists on this point, the Project will proceed without a limitation on the scope of potential changes due to this issue, recognizing that this can be revisited at any time.

⁵ The FERC SMD NOPR was issued in July 2002. A summary of key dates related to SMD is located at: <http://www.ferc.gov/Electric/rto/Mrkt-Strct-comments/nopr/smd-key-dates.pdf>. The California ISO plans to submit "Reply Comments" by a February 17, 2003 deadline. A FERC whitepaper on SMD is scheduled for release in April 2003, and a Final Rule is to be published in Summer 2003. As of January 2003, there is some speculation that this will be delayed due to opposition from various quarters.

Goals/Objectives:

Primary Goals/Objectives: [List in business terms the project's primary purpose and the high level results expected from its completion]

The primary goal of the 2004 GMC Rate Structure Project is through a stakeholder process develop and implement a GMC rate methodology that best supports the new and still changing market design in a way that achieves equity between Market Participants and provides for the collection of the ISO's costs.

The objectives of this effort are to:

- Develop a rate structure that meets the FERC "just and reasonable" standard, and appropriately allocates ISO costs among the ISO's users.
- Develop a rate structure based on the principle of cost causation which charges customers for the cost of services that they use/cause;
- Design a rate structure that is easy to administer (including reasonably cost effective, and benefits of change should outweigh the costs) and understandable;
- Develop a rate structure that does not result in unmanageable adverse operational impacts;
- Develop a rate structure that is arrived at through an open and balanced stakeholder process;
- Recover approved ISO costs in a stable, low risk manner without excess volatility;
- Have the new rate structure filed with FERC by November 1, 2003, so that it can be effective January 1, 2004, and
- Meet the terms of the 2002 GMC Settlement Agreement, which set forth issues to be covered in this 2004 GMC Stakeholder Process.

Benefits: [List the key advantages of accomplishing the project. State in terms of tangible savings, wherever possible]

Advantages of accomplishing this project include:

- Responding to the FERC Administrative Law Judge's 2001 GMC Initial Decision.
- A periodic review of the appropriateness of the ISO GMC structure.

From the ISO's perspective, additional advantages of accomplishing this project include:

- Development of better working relationships with Market Participants.
- Potential for reduced litigation at FERC related to future GMC filings.
- Possible better alignment of operational incentives with financial incentives affecting both the ISO and market participants.

Scope: [Describe the boundaries of the project in terms of what it includes and what it does not include]

Develop GMC rate structure to be effective January 1, 2004 that considers and evaluates various rate methodologies/structures, including but not limited to, the one currently in use,

and the applicability of each proposal to the needs of impacted parties, including Market Participants and the ISO. This effort will actively seek stakeholder participation in the development of the recommended solution. Feedback regarding disposition of all participation, including proposal status and comment review will be provided to all participants.

This effort will produce recommendation(s) that are given to the ISO. The ISO will set forth such recommendation(s) in the memorandum to the Board of Governors. The ISO Board of Governors will determine the 2004 GMC rate methodology to be filed by the ISO with FERC. Excluded from the scope of this effort are issues related to the level or composition of the ISO budgets. However, ISO spending on various elements of the ISO's changing responsibilities related to MD02 and/or SMD may be considered as appropriate in the consideration of rate structure. Stakeholders recognize that integration of the ISO budget process and the rate structure is necessary to arrive at a November 1, 2003 filing that incorporates these elements.

Product Deliverables: [The major elements of work that will be completed on the project. The set of specific, measurable, tangible, verifiable results expected from the completion of the project]

- § A project charter agreed to by all participants.
- § Proposals from the Market Participants and the ISO regarding rate design options.
- § A tool showing potential rates to aid in analysis of overall rate design proposals, and to permit consideration of GMC charges for various scheduling coordinators.
- § A preliminary Cost Allocation Matrix to set forth costs for various potential ISO service categories.
- § A rate design proposal for ISO Governing Board approval.

Constraints: [List the factors that limit the project team's options (schedule, cost or scope/quality). Indicate which is the driving factor for the project; i.e. a predefined budget constrains scope and staffing]

- Project due date is constrained by the FERC rate filing schedule (outside project control).
- Lack of clarity regarding ultimate MD02/SMD timeline and elements.
- Lack of data on the future effect of MD02/SMD market rules.
- Historical data on potential billing determinants and the level of granularity of cost/accounting records
- Finite team resources limit exploration and analysis of alternatives.

Risks: [State the major exposures to possible delay, or failure in meeting the stated goals/objectives of the project]

1. Time constraints of all parties due to the changes in market structure both by the ISO's MD02 and FERC's Standard Market Design Notice Of Proposed Rulemaking.
2. Inability to reach consensus on a rate design could result in extended litigation at FERC.
3. Lack of data regarding the effect of MD02 market changes and timing issues of MD02 could result in the adoption of a rate design that has significantly different impacts than anticipated.
4. Market instability due to regulatory risk and the potential for creditworthiness issues could divert team attention from this effort.

ISO Project Leads:			Debi Le Vine, Contracts;	Phil Leiber, Finance
ISO Team Members:				
Jan Addy, Project Office;	Ben Arikawa, Finance;	Mike Epstein, Finance;		
Don Fuller, Settlements;	Deane Lyon, OSAT;	Kevin Graves, Ops, Eng & Maintenance;		
Mike McGuffin, Settlements;	Mike Peterson, OSAT;	Stephen Morrison, Legal & Regulatory;		
David Withrow, Policy Office;		Kyle Hoffman, Client Relations		
ISO Project Executive Sponsor:		Bill Regan, CFO		

Note:

Team members listed above were those identified and assigned to support the project at its inception or during its early stages. Subsequently, other staff may have supplemented or replaced certain of these.

Project Milestones: [If possible, list the key accomplishment points, required approvals, set dates.]

1. Process Kickoff with Stakeholders August 29, 2002
2. Develop and approve Project Charter
3. Develop and approve evaluation criteria for proposals
4. Proposals due from Market Participants and ISO
5. Proposal evaluation
6. Develop recommended solution
7. ISO provide update to MIF during process
8. ISO present to ISO Governing Board May 2003

APPENDIX 2

PARTICIPANTS IN THE STAKEHOLDER PROCESS

Qualifying Facilities (QFs)

- Cogeneration Association of California/Energy Producers & Users of California (CAC/EPUC)

Governmental / Municipal Utilities:

- California Department of Water Resources/State Water Project (CDWR/SWP), California Municipal Utilities Association (CMUA),
- Modesto Irrigation District (MID),
- Northern California Power Authority (NCPA)
- Navigant Consulting (representing municipal utilities),
- Turlock Irrigation District (TID)
- Western Area Power Authority (WAPA).

Regulators

- California Public Utilities Commission (CPUC)
- Federal Energy Regulatory Commission (FERC) staff
- California Electricity Oversight Board (EOB),

Investor Owned Utilities

- Pacific Gas & Electric Company (PG&E)
- San Diego Gas & Electric (SDG&E)
- Southern California Edison (SCE)

Other (Generators, Marketers, etc.)

- Independent Energy Producers Association (IEPA),
- Mirant
- Sempra
- Energy Management Services (EMS)

APPENDIX 3**SUMMARY OF PROPOSED FUNCTIONALIZATIONS AND COMPARISON TO CURRENT GMC STRUCTURE**

Attribute	Current GMC Structure	California ISO 2004 Proposal	Modesto Irrigation District	Southern California Edison
Number of Functions	3 functions	3 primary functions, with a total of 6 sub-functions.	3 functions	5 functions
Functions	1. Control Area Services ("CAS") 2. Congestion Management ("CONG") 3. Ancillary Services and Real Time Energy Operations ("ASREO")	1. Grid Reliability Services a. Core Reliability Services (CRS) b. Energy & Transmission Services (ETS) 2. Market Services a. Forward Scheduling b. Congestion Management c. Market Usage 3. Settlements, Metering & Client Relations	1. Resolving Energy Imbalances (REI) 2. Managing Transmission Flows (MTF) 3. Administering Markets	1. Control Area Services (CAS) 2. Dynamic Dispatch Export Services (DDES) 3. Scheduling Service (SS) 4. Market Operation Services (MOS) 5. Real Time Operation Services (RTOS or RMOS)
Costs associated with each (as percentage of total ISO costs)	1. 58% 2. 12% 3. 30%	1a. 39% 1b. 16% 2a. 8% 2b. 4% 2c. 12% 3. 20% (Percentages are prior to reallocation of Settlements, Metering & Client Relations Costs to other categories)	1. 18% 2. 54% 3. 28%	1. 70.3% 2. 0.1% 3. 6.8% 4. 15.6% 5. 7.1%

Attribute	Current GMC Structure	California ISO 2004 Proposal	Modesto Irrigation District	Southern California Edison
Total number of billing determinants or rates	3	7	6 or 7	5
Billing Determinants for each function	1. Gross Control Area Load & Exports in MWh 2. Net Interzonal Scheduled Load in MWh 3. Purchases and sales of AS, instructed energy and uninstructed deviations in MWh (at a resource level)	1a. Non-coincident peak demand including behind the meter demand in MW 1b. Net control area load plus exports in MWh Net uninstructed deviations in MWh 2a. Number of schedules submitted to SI (load, generation, import, export, inter-SC trade, awarded AS (including self-provided) 2b. Net HA Scheduled interzonal power flows per path in MWh 2c. Purchases and sales of AS, instructed energy and net uninstructed deviations at an SC portfolio level (differs from current ASREO billing determinant) 3. Per SC ID charge of \$500, with remaining costs recovered over the ETS, CONG, and Market Usage service categories.	1a. Uninstructed deviation energy (MWh) (with two tiers) 1b. Uninstructed demand (MW) (with two tiers) 1c. Number of SC IDs 2a. Power withdrawals from the ISO grid in MWh 2b. OPTIONAL: Maximum power withdrawals (12 NCP) from the ISO grid in MW 2c. Number of SCs 3. Trading volumes (purchases and sales of Ancillary Services & instructed energy) in MWh	1. Net control area load plus exports in MWh 2. Exports from Mohave to NP and SRP in MWh 3. Scheduled load in MWh 4. Purchases and sales of AS and instructed energy in MWh 5. Net uninstructed deviations in MWh

California ISO

Designated Recipient:

Nature of Data: Bill impact analysis for 2004 GMC Rate Structure Project

Dated: July 7, 2003

Date of Release:

Disclaimer Regarding the Attached Data

purpose of furthering discussion and research in the ISO's '2004 GMC Rate Structure Project'. The data, in the form attached, is provided in response to Stakeholders' requests and as such does not necessarily indicate the ISO's concurrence in, or support for, its usefulness in developing a rate methodology. No implications may be drawn regarding the ISO's position on any subject in the Project from either the inclusion or exclusion of any specific data. The ISO does not warrant the completeness or accuracy of the data.

This data is subject always to the Disclaimer issued by the ISO at the time of its distribution.

Rate Proposal Overview

This data is subject always to the Disclaimer issued by the ISO at the time of its distribution.

EXISTING STRUCTURE																
	Control Area Services		Congestion Management		Ancillary Services and Real Time Energy		Total									
% of Total	58%	12%	30%	100%												
Revenue Requirement 9/2001-8/2002 Volume	\$ 137,856,869	\$ 27,400,520	\$ 72,342,981	\$ 237,600,371												
Rate / MWh	\$ 251,615,170	\$ 87,927,387	\$ 73,292,051													
Description	Gross Control Area Load & Exports	Net HA Scheduled interzonal flows	Purchases & sales of A/S, instructed energy and the absolute value of uninstructed deviations													
ISO PROPOSED STRUCTURE																
	Core Reliability Services		Energy & Transmission Services Load		Energy & Transmission Services Deviation		Forward Scheduling		Congestion Management		Market Usage		Settlements, Metering and Client Relations		Total	
% of Total	39%	13%	3%	8%	4%	12%	20%	100%								
Revenue Requirement 9/2001-8/2002 Volume	\$ 93,544,836	\$ 30,670,132	\$ 7,667,533	\$ 19,039,848	\$ 10,017,448	\$ 28,775,078	\$ 47,885,496	\$ 237,600,371								
Rate / MW, MWh, Cust Mo	534,042	239,850,597	16,403,169	12,307,710	87,927,387	45,707,872	1,562									
Rate / MWh Cust Serv Adder	\$ 175,164	\$ 0.128	\$ 0.467	\$ 1,547	\$ 0.114	\$ 0.630	\$ 500.00									
Total Rate / MW, MWh, Cust Mo	\$ 175,164	\$ 0.237	\$ 0.865	\$ 1,547	\$ 0.164	\$ 0.850	\$ 500.00									
Description	Metered non-coincident peak demand MW	Controlled Grid Load plus exports	Absolute value of net uninstructed deviations by settlement interval in MWh	Final HA schedules submitted, no charge for changes to DA schedules	Net Scheduled Interzonal load (flows)MWh	Purchases and sales of Ancillary Services, instructed energy and absolute value of net uninstructed deviations by settlement interval MWh	Number of customer months									

Rate Proposal Overview

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EXISTING STRUCTURE						Control Area Services	Congestion Management	Ancillary Services and Real Time Energy	Total
% of Total		58%		12%		30%		100%	
Revenue Requirement	\$	137,856,869	\$	27,400,520	\$	72,342,981	\$	237,600,371	
9/2001-8/2002 Volume		251,615,170		87,927,387		73,292,051			
Rate / MWh	\$	0.548	\$	0.312	\$	0.987			
Description		Gross Control Area Load & Exports		Net HA Scheduled interzonal flows		Purchases & sales of A/S, instructed energy and the absolute value of uninstructed deviations			

MID PROPOSED STRUCTURE
Option A - Demand charge on MTF

% of Total	6%	12%	0%	18%	35%	0%	5%	23%	100%
Revenue Requirement	\$	\$	\$	\$	\$	\$	\$	\$	\$
9/2001-8/2002 Volume Base/Tier 1	14,393,400	27,844,589	195,250	43,519,838	84,190,810	585,750	12,326,784	54,543,951	237,600,372
9/2001-8/2002 Volume Tier 2	4,868,337	3,746	1,562	242,456,619	534,042	1,562	5,383,631	23,921,072	
Rate / MWh or MWh Base/Tier 1	11,534,832	44,179							
Rate / MWh or MWh Tier 2	0.065	14,899	125,000	0.179	157,648	375,000	2,290	2,280	
Description	Uninstructed deviation energy	Uninstructed deviation demand (most recent 12 months)	Number of customer months	Power withdrawals	Max power withdrawals (12 MGP)	Number of customer months	Trading volumes	Trading volumes	Trading volumes

MID PROPOSED STRUCTURE
Option B - No demand charge on MTF

% of Total	6%	12%	0%	54%	0%	5%	23%	100%
Revenue Requirement	\$	\$	\$	\$	\$	\$	\$	\$
9/2001-8/2002 Volume Base/Tier 1	14,393,400	27,844,589	195,250	127,710,648				
9/2001-8/2002 Volume Tier 2	4,868,337	3,746	1,562	242,456,619				
Rate / MWh or MWh Base/Tier 1	11,534,832	44,179						
Rate / MWh or MWh Tier 2	0.065	14,899	125,000	0.527				
Description	Uninstructed deviation energy	Uninstructed deviation demand (most recent 12 months)	Number of customer months	Power withdrawals	Number of customer months	Trading volumes	Trading volumes	Trading volumes

Rate Proposal Overview

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EXISTING STRUCTURE		Control Area Services		Congestion Management		Ancillary Services and Real Time Energy		Total
		58%	12%	30%	100%			
% of Total								
Revenue Requirement		\$	\$	\$	\$			
9/2001-8/2002 Volume		137,856,869	27,400,520	72,342,981	237,600,371			
Rate / MWh		251,615,170	87,927,387	73,292,051				
Description		0.548	0.312	0.987				
		Gross Control Area Load	Net HA Scheduled	Purchases & sales of AS				
		& Exports	interzonal flows	instructed energy and the				
				absolute value of				
				uninstructed deviations				
SCE PROPOSED STRUCTURE (10 percent DDES rate)		CAS		BDES		SS		Total
		10%						
% of Total								
Revenue Requirement		\$	\$	\$	\$	\$	\$	
9/2001-8/2002 Volume		167,089,477	230,558	3,300,000	16,270,959	237,779,865	37,136,426	237,600,371
Rate / MW or MWh		239,156,619	3,300,000	0.070	0.068	0.068	1.267	
Description		MWh of Control Area	MWhs of gen dynamically dispatched to other Control	MWh of scheduled energy + self-provided AS (final schedules)	MWh of pur/sales of energy + AS	MWh of uninstructed imbalance energy		
		Load (Exclusive of retail behind-the-meter)	Areas over non-ISO Transmission					

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CALIFORNIA ISO

California Independent
System Operator

California ISO

**Rate Structure Proposal
For the
2004 GMC Rate Structure Project**

**Project Co-Leads:
Phil Leiber
Debi Le Vine**

July 9, 2003

California ISO White Paper on Rate Structure Proposal

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1. Executive Summary

This white paper summarizes the California ISO's proposed 2004 GMC rate structure. We have worked closely with stakeholders and, wherever possible, this proposal includes concepts put forth in other parties' rate proposals. The proposal was developed by California ISO staff with the assistance and expertise of rate design consultants Barkovich & Yap Inc.

Overall, the proposal meets the imperatives of the FERC ALJ's Initial Decision to address further unbundling of CAISO rates, consider demand charges, and to consider alternative methods of cost assignment of certain cost centers. Compared to the current GMC, it contains elements such demand charges that would provide for a more stable revenue structure for the California ISO, while still maintaining some charges that vary depending on customers' participation in the markets. We believe it satisfies the criteria from the 2004 GMC Rate Structure Project Charter:

- Develop a rate structure that meets the FERC "just and reasonable" standard, and appropriately allocates ISO costs among the ISO's users;
- Develop a rate structure based on the principle of cost causation which charges customers for the cost of services that they use/cause;
- Design a rate structure that is easy to administer (including reasonably cost effective, and benefits of change should outweigh the costs) and understandable;
- Develop a rate structure that does not result in unmanageably adverse operational impacts;
- Develop a rate structure that is arrived at through an open and balanced stakeholder process;
- Recover approved ISO costs in a stable, low risk manner without excess volatility;
- Have the new rate structure filed with FERC by November 1, 2003, so that it can be effective January 1, 2004; and,
- Meet the terms of the 2002 GMC Settlement Agreement, which set forth issues to be covered in this 2004 GMC Stakeholder Process.

Under this proposal, the Grid Management Charge would consist of three separate functions. Two of the functions would be sub-functionalized – thus resulting in a total of six "buckets" for charging customers. These functions, with their associated sub-functions are:

1. **Grid Reliability Services** - Under Grid Reliability Services, the California ISO provides safe, reliable operation and maintenance of the Control Area, provision for transmission expansion, coordination with neighboring Control Areas, management of transmission flows and compliance with regional and national reliability standards.
 - a. **Core Reliability Services (CRS)**- This service provides for reliable operation of a Control Area surrounded by other control areas and achieving minimal disruptions to system operation. In this sub-function, the ISO provides a stable grid and meets regional and national regulatory requirements, such as NERC and WECC reliability criteria and some FERC requirements (e.g., a basic level of transmission planning). All necessary activities attributable to Control Area

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operation including the capability of handling a system that is as geographically dispersed as the present system but without features that are scalable (i.e., that vary according to use or size of flow) are contained in this function. However, only a basic level of activity is contained in this service. The level of activity does not represent fully functioning operations for a robust Control Area in which there are outages and growth as new generation and transmission projects are developed.

- b. **Energy and Transmission Services (ETS)** – This service represents the *scalable* portion of Grid Reliability Services, and is a function of the intensity of use of the transmission system within the Control Area and the occurrence of system outages and disruptions (e.g., weather-related incidents).
2. **Market Services** - Under Market Services, the California ISO provides access to its scheduling infrastructure, manages congestion to facilitate transmission flows, operates and maintains California ISO markets for participants, and monitors market performance. Contained in this function are activities related to the maintenance, monitoring, operation and performance of the forward and Real-Time markets. These activities span many of the activities within the California ISO's current Congestion Management and Ancillary Services/Real-Time Energy Operations services.
 - a. **Forward Scheduling** - The California ISO provides SCs with the ability to forward schedule energy and Ancillary Services and the processing of accepted Ancillary Services bids. In this context, a schedule is represented by a scheduling template (import, export, load, generation, inter-SC trade and Ancillary Services, including self-provided AS) submitted to the California ISO Scheduling Infrastructure.
 - b. **Congestion Management (CONG)** - The California ISO provides management and operation of inter-zonal congestion markets, using adjustment bids, taking Firm Transmission Rights and Existing Transmission Contracts into account, and determining the price for mitigating congestion for flows on congested paths. Congestion exists when power flowing on a transmission path exceeds the transmission path capacity. Congestion management is conducted by the California ISO during the scheduling process and results in the economic rationing of transmission service in order to prevent congestion. This currently provides for only inter-zonal congestion. Intra-zonal congestion is managed in real-time and thus incorporated in Core Reliability Services.
 - c. **Market Usage** - In this sub-function of Market Services, the California ISO processes supplemental energy and Ancillary Service bids, maintains and controls the Open Access Same-Time Information System (OASIS), monitors market performance, ensures generator compliance with market protocols, and determines market clearing prices. In the future, activities associated with forward energy markets will be included here.

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3. **Settlements, Metering and Client Relations (CS)**- Under Settlements, Metering and Client Relations, the California ISO maintains customer accounts data, provides account information to customers, responds to customer inquiries, calculates market charges, processes settlement statements, resolves customer disputes and provides customer training. This function includes Settlements, Billing, and Metering activities as well as Client Relations. Some portion of Settlements activities are assigned to other functions. For example, RMR Settlements is assigned to CRS because its activities are related to the maintenance and provision of RMR services to the Control Area.

The table below summarizes the California ISO rate proposal. The indicative rates include billing determinants developed since the initial distribution of potential billing determinants for proposal development, including the number of schedules for the Forward Scheduling service category, and billable quantities on customer invoices. Historical billing determinants were taken from the period September 2001 to August 2002. Costs are the 2003 budgeted revenue requirement. Proposed rates for 2004 will be based on forecasted billing determinant volumes, and budgeted 2004 costs, as a result, the actual rates for 2004 will differ from those shown in the table below. Additionally, the rates and revenue requirements shown here are prior to the application of any mitigation or transitional measures that may be applied.

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Summary of California ISO Rate Proposal						
Functionalization, Billing Determinants, Revenue Requirement and Rates						
Function	Reliability Services		Market Services			Settlements, Metering and Client Relations
Sub-Function	Core Reliability Services	Energy and Transmission Services	Forward Scheduling	Congestion Management	Market Usage	
Billing determinant	Gross non-coincident peak demand MW	Net Control Area Load plus exports and absolute value of net uninstructed deviations by settlement interval MWh	Final HA schedules submitted, no additional charge for changes to DA schedules	Net Scheduled Interzonal load (flows) MWh	Purchases and sales of Ancillary Services, instructed energy and absolute value of net uninstructed deviations by settlement interval MWh	Fixed charge per SC ID
Approximate revenue requirement (in millions)	\$93.5	\$38.2	\$19.0	\$10.0	\$28.8	\$47.9
Approximate billing determinant quantity (based on 9/2001-8/2002)	534,042 MW-months	242.5 TWh (load and exports) and 16.4 TWh (net uninstructed deviations)	12.3 million schedules	87.9 TWh	45.7 TWh	Approximately 1,562 customer months
Approximate rates not including Settlements, Billing and Client Relations adder	\$175.16 per MW-month	\$0.13 per MWh (load and exports) and \$0.47 per MWh (net uninstructed deviations)	\$1.55 per schedule	\$0.11 per MWh of Scheduled Interzonal flow	\$0.63 per MWh	\$500 monthly per SC ID Remaining costs are associated with other billing determinants
Approximate rates including Settlements, Billing and Client Relations adder	\$175.16 per MW-month	\$0.23 per MWh (load and exports) and \$0.87 per MWh (net uninstructed deviations)	\$1.55 per schedule	\$0.16 per MWh of Scheduled Interzonal flow	\$0.85 per MWh	\$500 monthly per SC ID
Revenue requirements, billing determinants and rates shown in this table are approximate amounts and are subject to change with further refinement in methods.						

California ISO White Paper on Rate Structure Proposal

2. Introduction

This document and its attachments detail the California Independent System Operator's (California ISO) rate structure proposal as part of the 2004 GMC Rate Structure Project to redesign the structure of its Grid Management Charge (GMC) in accordance with the Initial Decision in ER 01-313-000, *et. al.* and the Settlement Agreement in ER 02-250-000, *et. al.*. They also serve to describe and record the efforts of the California ISO in developing the proposal.

In developing this proposal, the California ISO and participants reviewed the rate structures of other North American Independent System Operators, Federal Energy Regulatory Commission (FERC) ratemaking standards and traditional and marginal cost ratemaking methodologies. In addition, the California ISO worked with participants to review the California ISO's current GMC structure and cost accounting methods and to develop a comprehensive listing of California ISO activities. The California ISO and participants also worked together to develop a list of potential billing determinants for use by any party in developing their own proposal.

The California ISO adopted, where possible, reasonable and appropriate concepts put forth in other parties' rate proposals. The California ISO also took note of the imperatives of the Initial Decision to unbundle California ISO rates, consider demand charges, and to look at alternative methods of cost assignment of certain cost centers.

The California ISO also kept in mind the criteria set forth in the 2004 GMC Rate Structure Project Charter (detailed in Section 1 of this document.)

3. Overview of Proposal

Table 1 Summary of the California ISO Rate Proposal Functionalization and Billing Determinants						
Function	Grid Reliability Services		Market Services			Settlements, Metering and Client Relations
Sub-Function	Core Reliability Services	Energy and Transmission Services	Forward Scheduling	Congestion Management	Market Usage and Services	
Billing Determinant	Non- coincident peak demand (MW)	(1) ISO Controlled Grid Load plus exports and (2) absolute value of net uninstructed deviations by settlement interval MWh	Final HA schedules submitted, no charge for changes to DA schedules	Net Scheduled Interzonal flows MWh	Purchases and sales of Ancillary Services, instructed energy and absolute value of net uninstructed deviations by settlement interval MWh	(1) Fixed monthly charge per customer (2) Remaining costs to be recovered by association with other billing determinants

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The table above summarizes the functionalization aspect of the California ISO rate proposal. The Grid Management Charge would consist of three functions. Two of the functions would be sub-functionalized. These functions, with their associated sub-functions are:

1. Grid Reliability Services
 - a. Core Reliability Services
 - b. Energy and Transmission Services
2. Market Services
 - a. Forward Scheduling
 - b. Congestion Management
 - c. Market Usage and Services
3. Settlements, Metering and Client Relations

These are described more fully below.

3.1 Grid Reliability Services

The California ISO provides for the safe, reliable operation and maintenance of the Control Area, provides for transmission expansion planning coordinates with neighboring Control Areas, manages transmission flows and complies with regional and national reliability standards.

The following is a partial listing of activities in Grid Reliability Services (a more complete list is in Attachment A):

- Monitoring of system conditions and dispatching to maintain reliability
- Coordination, communication, and integration with neighboring Control Areas
- Intertie scheduling
- Compliance with reliability standards
- Transmission and generation outage coordination
- Management, monitoring and approval of new generator interconnections
- Evaluation of transmission expansion
- Performance of operational studies, system security analyses and system planning studies to ensure overall reliability

Portions or all of the following systems can be attributed to Grid Reliability Services:

- Energy Management System (EMS)
- Bill's Interchange Transaction Management System (BITS)
- Out-of-Sequence and Out-of-Market Settlements Information System (OSMOSIS)
- Global Reliability Resource Management Application (GRMMA)
- Automated Dispatch System (ADS)
- Scheduling Logging for the ISO of California (SLIC)
- Generator Communication Project (GCP)
- Electronic Tagging (ETAG)

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The Grid Reliability Services function consists of two sub-functions, Core Reliability Services and Energy and Transmission Services.

3.1.1 Core Reliability Services

The California ISO provides a basic level of reliable operation of a Control Area surrounded by other control areas and achieving minimal disruptions to system operation. In this sub-function, the California ISO provides a stable grid and meets regional and national regulatory requirements of such agencies as the North American Electric Reliability Council (NERC), the Western Energy Coordinating Council (WECC) the North American Energy Standards Board (NAESB), the Department of Energy and the FERC. All necessary activities attributable to Control Area operation including the capability of handling a system that is as geographically dispersed as the present system, but without features that are scalable (i.e., that vary according to use or size of flows) are contained in this function. However, only a basic level of activity is contained in this service. The level of activity does not represent fully functioning operations for a robust Control Area in which there are outages and growth as new generation and transmission projects are developed.

These services must be constantly available in order for the Control Area to operate reliably and must reflect the fact that the Control Area is interconnected with and interacting with other Control Areas and in compliance with all regulatory mandates placed on it.

Included in the costs of these services are the costs of systems applications necessary to operate the Control Area.

The charge to recover the costs of this service would be assessed on the metered non-coincident peak (NCP) demand of Scheduling Coordinators (SCs) on a monthly basis. The ISO is no longer proposing to calculate a separate adder for behind the meter Standby Load and behind the meter load of other entities. At this time, the ISO is waiting for the final Commission decision in the QF PGA, ER98-997-000 to determine how SCs may comply with the metering requirements of the ISO Tariff.¹

3.1.2 Energy and Transmission Services

The California ISO provides for the safe, reliable operation of the Control Area assuming everyday (normal and extraordinary) operational requirements in which outages and disruptions (such as weather-related incidents) occur. This is the scalable portion of Grid Reliability Services that is necessary to respond to the everyday occurrence of system activity.

The level of activity is a function of the intensity of use of the transmission system within the Control Area and the occurrence of system outages and disruptions (e.g., weather-related

¹ The ISO Tariff requires SCs to schedule and meter gross demand and generation. However, the ISO waived this requirement for Qualifying Facilities pending a final FERC decision in ER98-997-000. An Initial Decision has been issued, but the Commission has not yet voted to affirm that decision.

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incidents). This includes the services for simultaneously managing energy imbalances and transmission flows beyond those in a steady state Control Area.

For example, grid planning requires more resources in a control area that has growing load and significant need for new transmission and generation facilities. The use of the grid will be more intense if load-serving entities generate only part of their own power and buy part, bringing it to load centers through the grid within the Control Area. A higher level of net uninstructed deviations will increase the workload of the California ISO, since actions must be taken to offset these deviations to ensure system-wide balance in real time.

Included in the costs of Energy and Transmission Services are the scalable portion of systems applications and the hardware necessary to operate the Control Area.

In this sub-function, the level of activity within the Control Area drives costs. Thus, they will vary with the volume of flows and the level of net uninstructed deviations within a settlement period. Two volumetric billing determinants will be used: monthly ISO Controlled Grid Load² plus exports (MWh) and the absolute value of net uninstructed deviations by settlement interval (in MWh).

3.2 Market Services

Under Market Services, the California ISO provides access to its scheduling infrastructure, manages congestion to facilitate transmission flows, operates and maintains California ISO markets for participants, and monitors market performance.

Contained in this function are activities related to the maintenance, monitoring, operation and performance of the forward and Real-Time markets. These activities span many of the activities within the ISO's current Congestion Management and Ancillary Services/Real-Time Energy Operations services.

The following is a partial listing of activities in Market Services (a more complete list is found in Attachment A):

- Processing forward market schedules
- Adjusting forward market schedules to mitigate transmission congestion
- Maintaining market information postings
- Operating Real-Time market
- Determining market clearing prices
- Administering primary and secondary Fixed Transmission Rights markets
- Monitoring market performance

Portions or all of the following systems can be attributed to Market Services:

² The ISO Controlled Grid includes the system of transmission lines and associated facilities of the Participating Transmission Owners that have been placed under the ISO's Operational Control.

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- Scheduling Infrastructure (SI)
- Scheduling Applications (SA)
- Open Access Same-Time Information System (OASIS)
- Automated Dispatch System (ADS)
- Balancing Energy Ex-Post Pricing (BEEP)
- Automated Load Forecasting (ALFS)
- Firm Transmission Rights (FTRs) and Secondary Registration System (SRS)
- Outage Scheduler (OS)
- Existing Transmission Contracts (ETC)
- Congestion Management (CONG)
- Day Ahead Data Analysis Tool (DADAT)
- Hour Ahead Data Analysis Tool (HADAT)

The Market Services function consists three sub-functions, (1) Forward Scheduling, (2) Congestion Management, and (3) Market Usage and Service.

3.2.1 Forward Scheduling

The California ISO provides SCs with the ability to forward schedule energy and Ancillary Services and the processing of accepted Ancillary Services bids. In this context, a schedule is represented by a scheduling template (import, export, load, generation, inter-SC trade and Ancillary Services, including self-provided AS) submitted to the California ISO's Scheduling Infrastructure.

The following is a partial listing of activities in Forward Scheduling:

- Processing forward energy schedules, including inter-SC trades
- Reviewing and verifying schedules

The ISO processes schedules to confirm path ratings are not exceeded, to ensure that sufficient Ancillary Services (self-provided or market) are or will be procured and that SC portfolios are balanced.

The costs incurred by the California ISO are more closely correlated with the number of schedules than energy volumes, since the basic effort encompasses processing the schedules and bids regardless of the volume within the transactions. The billing determinant will be the number of final hour-ahead schedule templates submitted, not including changes to the DA schedule (so as not to discourage load-following).

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3.2.2 Congestion Management

The California ISO provides management and operation of inter-zonal congestion markets, using adjustment bids, taking Firm Transmission Rights and Existing Transmission Contracts³ into account, and determining the price for mitigating congestion for flows on congested paths. Congestion exists when power flowing on a transmission path exceeds the transmission path capacity. Congestion management is conducted by the California ISO during the scheduling process and results in the economic rationing of transmission service in order to prevent congestion. This currently provides for only inter-zonal congestion. Intra-zonal congestion is managed in real-time and thus incorporated in Core Reliability Services.

This service is similar to the CONG service in the current GMC rate design, but is not identical due to the other changes in this proposed rate design. When LMP is implemented, congestion management activities will be functionalized and their associated costs will be assigned to other service categories, eliminating this service category.

The costs of this service would be recovered through an assessment on net Hour-Ahead scheduled inter-zonal flows (loads).

3.2.3 Market Usage

In this sub-function of Market Services, the California ISO processes supplemental energy and Ancillary Service bids, maintains and controls the Open Access Same-Time Information System (OASIS), monitors market performance, ensures generator compliance with market protocols, and determines market clearing prices. In the future, activities associated with forward energy markets will be included here.

The following is a partial listing of activities in Market Usage and Service (a more complete list is in Attachment A):

- Maintaining market information postings
- Operating Real-Time market
- Determining market clearing prices
- Monitoring market performance

The costs of this service would be recovered through a per MWh charge on purchases and sales of Ancillary Services, instructed energy and the absolute value of net deviations by Settlement interval by SC ID. Self-provided Ancillary Services would not be assessed this charge.

³ The ISO Tariff defines Existing Contracts as “the contracts which grant transmission service rights in existence on the ISO Operations Date (including any contracts entered into pursuant to such contracts) as may be amended in accordance with their terms or by agreement between the parties thereto from time to time.” Further clarification on the ISO’s responsibility with respect to Existing Contracts can be found in Sections 2.4.3 (Existing Contracts for Transmission Service) and 2.4.4 (ISO Administration of Existing Contracts for Transmission Service). The list of Existing Contracts can be found in Appendix B to the Transmission Control Agreement.

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3.3 Settlements, Metering and Client Relations

Under Settlements, Metering and Client Relations, the California ISO maintains customer account data, provides account information to customers, responds to customer inquiries, calculates market charges, processes settlement statements, resolves customer disputes and provides customer training. This function includes Settlements, Billing, and Metering activities as well as Client Relations. Certain Settlements activities and some Contracts and Special Projects activities are assigned to Core Reliability Services. For example, RMR Settlements is assigned to CRS because its activities are related to the maintenance and provision of RMR services to the Control Area. Similarly, Contracts and Special Projects has a primary role in the administration of the Transmission Access Charge and the development of Metered SubSystems.

The following is a partial listing of activities in Settlements, Metering and Client Relations (a more complete list is in Attachment A):

- Determine charges associated with transmission services, forward market schedules, Real-Time balancing market, congestion management and administrative charges
- Maintain and process Settlements data
- Perform Settlement statement re-runs
- Manage and monitor SC credit and collateral
- Collect and validate meter data
- Provide ISO Tariff guidance to Market Participants
- Facilitate resolution of Market Participant issues
- Provide training to Market Participants

Portions or all of the following systems can be attributed to Settlements, Metering and Client Relations:

- Out-of-Sequence, Out-of-Market Settlements Information System (OSMOSIS)
- Balance of Business Systems (BBS)
- Meter Data Acquisition System (MDAS)

Settlements, Metering and Client Relations activities are essential to maintaining any connection between the SCs and the California ISO, regardless of the actual degree of service taken from the California ISO. It can be seen that there are major costs associated with this function. Thus, the mitigation of the bill impacts of assigning these costs on a per customer basis is essential and appropriate. For that reason, the California ISO proposes to recover these costs using both a small fixed monthly charge and a variable charge.

The fixed monthly charge is \$500 per SC ID. The remaining Settlements, Metering and Client Relations costs will be associated with the billing determinants of Energy and Transmission Services, Congestion Management and Market Usage. The billing determinants for these services are ISO Controlled Grid Load plus exports and net uninstructed deviations (Energy and Transmission Services), net scheduled interzonal flows (Congestion Management) and purchases and sales of Ancillary Services, instructed energy, and net uninstructed deviations (Market Usage). We made the decision not to associate costs to either Core Reliability Services or

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Forward Scheduling as these were new rates and any additional costs would increase the severity of bill impacts.

In order to associate the remaining costs with the other billing determinants, Barkovich and Yap and the ISO reviewed the occurrence of charge types in Settlement Statements over the test year period, September 2001 through August 2002. The occurrence of charge types in Settlement Statements is a measure of the activity flowing through Settlements. We associated each charge type with one of the three services above. The Settlement, Metering and Client Relations costs associated with each billing determinant were proportional to the relative number of charge types associated with each service.

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4. Comparison to Other ISOs/RTOs

Comparisons with other ISOs are difficult as there is no standard for ISO rates. It is also made difficult by the application of the FERC Uniform System of Accounts that were created for application to traditional integrated electric utilities. Nonetheless, in the following we attempt to make some high level comparisons between the California ISO's proposed new rate structure and that of other ISOs/RTOs. These comparisons are shown in Attachment B, in which we compare ISO functions and the method of recovery.

4.1 Grid Reliability Services

Of the five other ISOs (ISO-NE, NYISO, PJM, ERCOT and MISO), only ISO-NE and PJM have "Reliability" functions. ISO-NE's Schedule 3, Reliability Administration, appears to be similar to the California ISO's proposed Grid Reliability Services function. ISO-NE's billing determinant is non-coincident peak demand.

PJM's reliability functions are Schedule 9-1, Control Area, Schedule 9-5, Regulation and Frequency Response, and Schedule 9-7, Capacity and Resource Obligation Management. Schedules 9-1 and 9-5 are recovered through MWh assessments. Schedule 9-1 is recovered through an assessment on point-to-point and network integration services flows in MWhs. Schedule 9-5 is recovered through an assessment on PJM regulation and scheduled regulation, including self-scheduled regulation. Schedule 9-7 is allocated to PJM East and PJM West by their relative non-coincident peaks. Within each region, the cost is recovered by an assessment on resource obligations in MW-days.

4.2 Market Services

Of the other ISOs/RTOs, only ISO-NE and PJM have separate market functions. The market functions of the ISO-NE can be found in Schedule 1-Scheduling, System Control and Dispatch and Schedule 2-Energy Administration. Schedule 1 costs are recovered through an assessment on "monthly Network load in kW plus the highest amount of reserved capacity of point-to-point transmission plus the highest amount of authorized use." Schedule 2 costs are recovered by assessments on Transaction Units (bilateral contract block hours plus generator block hours plus net deviation block hours) and on load and injections (generation). Fifteen percent of the Schedule 2 costs are recovered from Transaction Units and 85 percent from load and injections.

The market functions of PJM can be found in Schedule 9-4-Market Support, and Schedule 9-3-Fixed Transmission Rights. Market Support costs are recovered from generation and load MWhs. Fixed Transmission Rights costs are recovered through a charge on FTR MW per hour summed over hours. (Essentially, this converts the FTR MWs to MWhs over the year.)

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4.3 Settlements, Metering and Client Relations

None of the other ISOs/RTOs have an explicit, separate Settlements, Metering and Client Relations function. All except the MISO have annual fees. These fees are described in Attachment B. ISO-NE, PJM and ERCOT have fixed annual fees varying from \$2,000 (ERCOT) to \$5,000 (ISO-NE and PJM). The NYISO and the Ontario IMO have tiered fees that vary by the amount of load an entity has. The NYISO has a \$5,000 fee for all other companies that do not have load.

4.4 Startup Costs

Only the NYISO has explicit recovery of start-up costs. For 2003, the monthly amount recovered is \$1,095,881. This amount is assessed equally to customers receiving transmission services under the Open Access Transmission Tariff (OATT) and to customers receiving Location Based Marginal Pricing (LBMP) market services. The current rate for those receiving service under the OATT is \$0.046223 per MWh, and the current rate for those receiving LBMP service is \$0.047346 per MWh.

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5. Cost Assignment Process

The process of identifying and assigning costs to functions and sub-functions was an iterative one. As the California ISO proposal developed, the California ISO's consultants, Barkovich and Yap, Inc., reviewed the current method of cost assignment using the Budget Tool and the resulting structure in the Cost Allocation Matrix (CAM). They then laid out a process in which directors and managers of directly assignable cost centers were asked to assign costs to the California ISO's proposed functions and sub-functions, ultimately to provide data for the ISO's Cost Allocation Matrix

Each set of directors and managers provided three major items. First, they provided a description of their cost center activities to each function or sub-function. Second, they assigned their personnel to the function or sub-function. Finally, they provided a justification of their personnel assignments. The results were tabulated in worksheets, which form the basis for the direct personnel assignments in the CAM.

Barkovich and Yap worked directly with most of the directors and managers, querying results, asking for clarifications, and compiling results. In most cases several meetings and conference calls were required before personnel assignments were completed.

For those cost centers that were not directly assignable, several different methods of assignment were used. The main methods were proportional to:

- Supervised cost center assignments;
- Departmental cost center assignments;
- Total directly assigned operating costs; or
- Total operating cost assignments.

The cost assignment of capital expenditures followed a method similar to that done for cost centers. Whenever possible, capital expenditures were directly assigned. This assignment was done in an iterative process by the directors and managers of the cost centers that utilized the systems. For those capital expenditures that could not be directly assigned, one of the methods in the list above was used.

The results of the cost assignments were linked to the CAM to create the revenue requirements for each function or sub-function. The resulting assignments are shown in the table below:

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Table 2	
Revenue Requirements by Function	
Grid Reliability Services	
Core Reliability Services	\$ 93,544,836
Energy and Transmission Services*	
Load and exports	\$ 30,670,132
Net Uninstructed Deviations	\$ 7,667,533
Total Grid Reliability Services	\$ 131,882,501
Market Services	
Forward Scheduling	\$ 19,039,848
Congestion Management	\$ 10,017,448
Market Usage	\$ 28,775,078
Total Market Services	\$ 57,832,374
Settlements, Metering and Client Relations	\$ 47,885,496
Total Revenue Requirement after application of reserve	\$ 237,600,371
Revenue requirements shown are based on 2003 Budget information. Cost assignments are preliminary. Further refinement may cause these assignments to change, and allocations will vary as a result of differing costs in the 2004 revenue requirement.	
*The Energy and Transmission Services costs are allocated 80 percent to Load and exports and 20 percent to net uninstructed deviations. This allocation was based on professional judgment.	

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6. Billing Determinants For Each Service

The California ISO and participants identified a number of potential billing determinants for use by participants and the California ISO early in the Project. This was done to allow the California ISO to begin collection of data and to prevent a lack of data from impeding progress on consideration of alternative rate designs. These list of possible billing determinants was posted on the GMC project website⁴.

As the California ISO proposal developed and the rate functions crystallized, we analyzed the various potential billing determinants for their suitability for use. This suitability analysis looked at two factors. We preliminarily determined if the billing determinant was causally related to the function for which it was to be used. Then we considered the billing determinant's potential stability, impact on operations and market participant behavior, and its availability in the Settlements system.

Based on this assessment, the California ISO determined that looking beyond the initial list of potential billing determinants was necessary. We found that certain transaction data were suitable for use as a billing determinant. This transaction data is discussed below.

6.1 Core Reliability Services

Core Reliability Services are the basic services needed to manage the Control Area reliably and safely. The billing determinant for this function should be reflective of the costs of maintaining operational control at all times of the day and seasons of the year, as well as the stress that entities place on the transmission system. The billing determinant selected is the monthly non-coincident peak (NCP) *demand* on a gross basis. An entity's NCP demand reflects the burden that the entity places on the operation of the transmission system.

Staff rejected use of an entity's coincident peak (CP) demand as the billing determinant. The coincident peak demand would not reflect the burden on system operation of entities whose peaks are not coincident with the system peak. Core Reliability Services must be provided at all times of the day, even to entities that have NCP demand occurring in the middle of the night.

6.2 Energy and Transmission Services

Contained within Energy and Transmission Services is the scalable portion of Grid Reliability Services. Scalability implies an increasing relationship with flows, outages and disturbances within the Control Area. The costs of managing the Control Area will be higher to the extent that total flows increase. They will also be higher to the extent that entities cause inadvertent flows that must be managed in real time. The billing determinants selected by the California ISO are the monthly ISO Controlled Grid Load plus exports and the absolute value of net

⁴ <http://www.caiso.com/docs/09003a6080/1e/f7/09003a60801ef7fb.pdf>.

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uninstructed deviations by Settlement interval. The first billing determinant represents total flows and the second represents inadvertent flows on the transmission grid.

The absolute value of net uninstructed deviations by Settlement interval is calculated as the absolute value of the difference between instructed energy and actual energy delivered net of changes in load. Allowing netting for changes in load permits SCs to load follow (match changes in load with changes in generation), which reduces inadvertent flows on the transmission grid.

6.3 Forward Scheduling

Forward Scheduling contains the activities associated with accepting, processing, and validating Day-Ahead and Hour-Ahead schedules. A schedule in this context is a template (import, export, load, generation, inter-SC trade, or Ancillary Service) submitted to the Scheduling Infrastructure. The costs in this sub-function relate to providing the infrastructure and to processing schedules.

All schedules are processed for each hour regardless of the time of submission. Scheduling applications run discretely for each hour and problems are resolved for each hour. The ISO re-processes each hour of a Day-Ahead schedule that rolls to the Hour-Ahead, even if it is unchanged.

The billing determinant selected by the California ISO for Forward Scheduling is the number of final Hour-Ahead schedules submitted. Only final Hour-Ahead schedules are assessed this charge. In order not to discourage SCs from modifying their Day-Ahead schedules due to better information, any changes from Day-Ahead schedules that roll over to the Hour Ahead will not be assessed an additional charge.

6.4 Congestion Management

Congestion Management contains the activities associated with mitigating scheduled transmission flows across Inter-zonal boundaries. To the extent flows increase across zonal boundaries, the California ISO incurs costs to monitor and potentially mitigate Inter-zonal congestion.

The billing determinant for Congestion Management will be assessed on net Hour-Ahead Scheduled Inter-zonal flows (load). This is the current billing determinant for the Congestion Management charge. An SC will be assessed this charge on a per MWh basis each time it schedules a flow across an Inter-zonal interface.

6.5 Market Usage

Market Usage contains the activities associated with processing Supplemental Energy and Ancillary Services, determining the Real-Time Market Clearing Price, maintaining and

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controlling the OASIS, monitoring market performance, and ensuring generator compliance with market protocols. In the future, activities associated with forward energy markets will be included here.

The costs of Market Usage will be recovered from those SCs that use the Real-Time market (and the forward energy markets in the future) in a charge based on usage of these markets. The billing determinant for Market Usage will be purchases and sales of Ancillary Services, Instructed Energy and the absolute value of net portfolio deviations by Settlement interval.

This differs from the billing determinant of the current Ancillary Services/Real-Time Energy Operations Charge in that the absolute value of **net** portfolio deviations is used rather than the absolute value of **total** deviations. As was mentioned earlier, to the extent an SC accurately load follows, the California ISO need not purchase Imbalance Energy. The use of net portfolio deviations is a specific mitigation not to discourage load following.

6.6 Settlements, Metering and Client Relations

Settlements, Metering and Client Relations contains most Settlements, Billing, Metering, and Client Relations activities. Settlements, Metering and Client Relations costs are a function of the interaction of the customer and the California ISO. As many of these costs are fixed in nature, such as the requirements for settlements, billing, and processing meter data, cost recovery through a fixed charge per customer may be appropriate. There are variations in the complexity of these interactions between the California ISO and its numerous customers, which militate against recovering these costs solely through a fixed charge.

If the California ISO recovered a major portion of these costs through a single fixed charge per customer, the bill impacts would be significant. As a mitigation measure, the California ISO proposes to recover a portion of Settlements, Metering and Client Relations costs through a \$500 per month customer charge per SC ID regardless of the level of activity.

As described above, the remaining Settlements, Metering and Client Relations costs have been associated with the billing determinants of Energy and Transmission Services, Congestion Management and Market Usage. The billing determinants for these services are ISO Controlled Grid Load plus exports and net uninstructed deviations (Energy and Transmission Services), net Hour-Ahead scheduled interzonal flows (Congestion Management) and purchases and sales of Ancillary Services, instructed energy, and net uninstructed deviations (Market Usage). We made the decision not to associate costs to either Core Reliability Services or Energy and Transmission Services as these were new rates and any additional costs would increase the severity of bill impacts.

Barkovich and Yap and the ISO reviewed the occurrence of charge types in Settlement Statements over the test year period, September 2001 through August 2002. We view the occurrence of charge types in Settlement Statements as a measure of the activity flowing through Settlements. We then associated each charge type with one of the three services above. The

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Settlement, Metering and Client Relations costs associated with each billing determinant were proportional to the relative number of charge types associated with each service.

Table 3 Billing Determinants by Function and Sub-Function	
Grid Reliability Services	
Core Reliability Services	534,042 MW-months (NCP demand)*
Energy and Transmission Services	
Controlled Grid Load plus exports	239,850,597 MWh
Absolute value of net uninstructed deviation by interval	16,403,169 MWh
Market Services	
Forward Scheduling	12,307,710 schedules
Congestion Management	87,927,387 MWh
Market Usage	45,707,872 MWh
Settlements, Metering and Client Relations	1,562 customer months
The California ISO collected billing determinants for the twelve-month period September 2001 through August 2002. This was done to facilitate the release of masked SC-specific information to participants under the conditions of providing data at least six months old. The California ISO will review more recent historical data to determine if the collected data is representative.	

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7. Proposed Rates

Based on the process outlined in this paper, the resulting rates are shown in Table 4. We caution that these rates are indicative of the rates that would apply using budgeted costs for the year 2003. Therefore, these can be only illustrative of the actual rates for 2004.

Table 4 Indicative Rates by Function and Sub-Function		
	Service alone	Including Settlements, Metering and Client Relations adder
1. Grid Reliability Services		
a. Core Reliability Services	\$175.16 per MW-month of NCP demand	\$175.16 per MW-month of NCP demand
b. Energy and Transmission Services		
Controlled Grid Load plus exports*	\$0.128 per MWh	\$0.237 per MWh
Absolute value of net uninstructed deviation by interval	\$0.467 per MWh	\$0.865 per MWh
2. Market Services		
a. Forward Scheduling	\$1.547 per schedule submitted	\$1.547 per schedule submitted
b. Congestion Management	\$0.114 per MWh	\$0.164 per MWh
c. Market Usage	\$0.630 per MWh	\$0.850 per MWh
3. Settlements, Metering and Client Relations		
	\$500 monthly per SC ID	\$500 monthly per SC ID

The functionalization undertaken here reflects an effort to maximize the cost basis of the California ISO's rates. In order to implement this functionalization, it is anticipated that there will be bill impacts that require mitigation. These bill impacts will be studied in depth along with the bill impacts of other proposals. Rates will be adjusted in order to reduce the level of bill impacts to a manageable and reasonable level while preserving the cost basis of the rates to the greatest extent possible.

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8. Remaining Issues

As in any undertaking of this magnitude, there are a number of remaining issues that the California ISO and participants must consider. These include:

1. Potential increased use of direct assignments of indirect expenditures. Participants in the 2004 GMC Rate Structure Project have requested that the CAISO make an effort to use the direct assignment approach versus an allocation approach in cost assignment process. For this proposal, we have directly assigned costs to the extent possible, and will continue to try to improve the cost allocation process that will be used in the rate filing made in fall 2003.
2. Potential refinement in the definition of the billing determinants. Based on past experience, in the transition from the conceptual design to the implementation of a rate design proposal, some minor modifications related to the definition of proposed billing determinants may be necessary. In the past, the need for such potential changes has been discovered during the drafting of tariff language, or in the development of formulas used to modify the billing system to implement the GMC structure.

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ATTACHMENTS

- A. Functionalization of Activities into Service Categories
- B. Comparison of Rate Structures of other ISOs