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March 11, 2004

The Honorable Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: California Independent System Operator Corporation
Compliance Filing
Docket No. ER03-1046-___

Dear Secretary Salas:

The California Independent System Operator Corporation ("ISO")[1] respectfully submits six copies of this filing in compliance with the Commission's "Order on Proposed Tariff Amendment No. 54," issued in the captioned docket on October 22, 2003, 105 FERC ¶ 61,091 ("Amendment No. 54 Order"). As described below, the ISO proposes changes to the ISO Tariff to comply with the Amendment No. 54 Order.

I. INTRODUCTION

In the Amendment No. 54 Order, the Commission directed the ISO to file, by January 20, 2004, a compliance filing "to correct any inconsistencies and invalid references in both its Tariff and Operating Protocols." Amendment No. 54 Order at P 126. On January 15, 2004, the ISO filed a motion for a 21-day extension of time so that its compliance filing would be due on February 10, 2004 instead of January 20. On January 16, 2004, the Commission issued a notice granting an extension of time for submitting the compliance filing to February 10. On February 9, 2004, the ISO filed a motion for a 30-day extension of time so that its compliance filing would be due on March 11, 2004 instead of February

[1] Capitalized terms not otherwise defined herein are used in the sense given in the Master Definitions Supplement, Appendix A to the ISO Tariff.

10. On February 11, 2004, the Commission issued a notice granting an extension of time for submitting the compliance filing to March 11.

II. TARIFF MODIFICATIONS

The ISO hereby provides the compliance filing required by the Amendment No. 54 Order. Attachment A to the present filing contains a table showing the inconsistencies and invalid references in the ISO Tariff and Protocols that the present filing is intended to correct. The first column in the table shows the numbers of the Tariff and Protocol sections in which the proposed changes should be made, the second column shows the changes, and the third column explains the reasons for the changes. The table in Attachment A includes the following:

- The correction of the use of terms defined in Appendix A to the ISO Tariff.[2]

- The deletion of definitions from the ISO Protocols that are identical or substantially similar to definitions in Appendix A to the ISO Tariff.

- The deletion of the outdated definition of the term "ISO Metered Entity" from several of the ISO Protocols; the current definition of that term is contained in Appendix A to the ISO Tariff.

- The deletion of several terms defined in the ISO Protocols that are also defined in substantially different words in Appendix A to the ISO Tariff. As explained in the table in Attachment A, the ISO has deleted these definitions from the ISO Protocols, and has adapted the words in the definitions to the definitions of the same terms in Appendix A to the Tariff.

- The deletion of outdated references to and provisions concerning the California Power Exchange ("PX") and the Western Systems Coordinating Council ("WSCC").[3]

- The correction of minor errors in spelling and punctuation.

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[2] In the Amendment No. 54 Order, the Commission stated that "[i]consistencies and interchangeable terms can cause confusion as to the proper implementation of Tariff protocols." Amendment No. 54 Order at P 124.

[3] In the Amendment No. 54 Order, the Commission noted intervenors' concerns that "[n]umerous references . . . remain to outdated market features such as the California PX." Amendment No. 54 Order at P 124. In addition, the table in Attachment A contains changes concerning the PX and power exchanges that conform to similar changes approved by the Commission in the proceeding on Amendment No. 56 to the ISO Tariff (Docket No. ER03-1221). *See* ISO Compliance Filing, Docket No. ER03-1221-002 (filed Nov. 17, 2003); *California Independent System Operator Corporation*, 106 FERC ¶ 61,062 (2004).

- The deletion or correction of erroneous or outdated cross-references to sections of the ISO Tariff and Protocols.

Attachment B to the present filing contains black-lined ISO Tariff sheets showing the changes described in the table found in Attachment A. Attachment C to the present filing contains revised ISO Tariff sheets that incorporate the changes described in the table found in Attachment A.

The ISO notes that the pages in Attachment C to the present filing contain certain ministerial changes relating to the combination of ISO Tariff sections accepted in different proceedings but not previously included together on the same Tariff sheet. These ministerial changes are contained on the following Tariff sheets: 20, 27, 173, 175, 176, 211, 250A, 307, 307A, 314A, 315A, 316, 316A, 337, 340, 345, 386, 649, and 717. In addition, Attachment C contains Tariff sheet 297P; this sheet includes changes that the ISO has already provided in black-line format in the Amendment No. 54 proceeding, but which the ISO inadvertently has failed to incorporate into a Tariff sheet provided to the Commission until now.

Moreover, the ISO has not included in the present filing proposed modifications to the Tariff and Protocols changes contained in Amendment No. 55 to the ISO Tariff (Docket No. 03-1102). The ISO is evaluating the effect of the Commission's most recent order concerning Amendment No. 55 on a number of the provisions in the Amendment No. 55 filing. *See California Independent System Operator Corporation*, 106 FERC ¶ 61,179 (2004). The ISO notes that some of the changes to the Market Monitoring and Information Protocol ("MMIP") contained herein are the same as some of the changes to the MMIP contained in the Amendment No. 55 filing, but this is only the case with regard to the removal of outdated references and provisions concerning the PX. For the reasons described above, the ISO is proposing these changes in the present filing.

III. COMMUNICATIONS

Communications regarding this filing should be addressed to the following individuals, whose names should be placed on the official service list established by the Secretary with respect to this submittal:

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IV. ATTACHMENTS

The following documents, in addition to this transmittal letter, support this filing:

Attachment A	Table showing proposed changes
Attachment B	Black-lined ISO Tariff sheets showing proposed changes
Attachment C	Revised ISO Tariff sheets
Attachment D	A form notice of this filing, suitable for publication in the Federal Register (also provided in electronic format)

Two extra copies of this filing are also enclosed. Please stamp these copies with the date and time filed and return them to the messenger. Please feel free to contact the undersigned if you have any questions concerning this matter.

Respectfully submitted,

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ATTACHMENT A

TABLE OF PROPOSED CHANGES

Section	Change	Reason for Change
Index to ISO Tariff	Make changes to and additions of section numbers, titles, and page numbers for Sections 3.3, 5.4, 5.7, 5.11-5.13, 7.5, 8.3, 8.5, 14.4, 23, 23.1-23.16, and 28	Update outdated index to reflect current section numbers, titles, and page numbers
2.2.2(d)	Change "self provided" to "self-provided"	Correct grammar
2.2.3.2	Change "Load" to "Demand" (2 places)	The correct tariff-defined term to use in the context of the section is Demand rather than Load
2.2.3.2	Change "UDCs" to "UDC's"	Correct grammar
2.2.4.5.1	Change "schedules" to "Schedules"	Not capitalized in section, but is a tariff-defined term
2.2.6.11	Change "ISO protocols" to "ISO Protocols"	Not capitalized in section, but is a tariff-defined term
2.2.7.3	Change "billed Load (in MWh)" to "billed Demand use (in MWh)"	The correct tariff-defined term to use in the context of the section is Demand rather than Load
2.2.8.1	Change "self provide" to "self-provide"	Correct grammar
2.2.10	Change "Coordinfators" to "Coordinators"	Correct typographical error
2.2.10.3	Change "Inter-zonal Interfaces" to "Inter-Zonal Interfaces"	Not capitalized in section, but is a tariff-defined term
2.2.10.3	Change "Loop-Flow" to "Loop Flow"	Tariff-defined term should not be hyphenated
2.2.11.1	Change "Load" to "Demand"	The correct tariff-defined term to use in the context of the section is Demand rather than Load
2.2.11.1.1	Change "Load" to "Demand"	The correct tariff-defined term to use in the context of the section is Demand rather than Load
2.2.11.4	Change "self provide" to "self-provide"	Correct grammar
2.2.11.4	Change "self provided" to "self-provided"	Correct grammar
2.2.11.4	Change "Self Provided" to "Self-Provided"	Correct grammar
2.2.11.5	Change "self provide" to "self-provide"	Correct grammar
2.2.12.2.3.1	Change "Market Option ('Market Hour')," to	Implement changes to language in section to conform with similar

Section	Change	Reason for Change
	"Market Option,"; change "RMR Energy" to "RMR Market Energy" (10 places); change "Market Hour" to "hour" (5 places)	changes in Section 2.2.12.2, *et seq.*, as approved in the proceeding concerning Amendment No. 56 to the ISO Tariff
2.2.12.2.3.1	Change "may bid into the PX Day-Ahead Market" to "may bid into a power exchange market"; change "in the PX Day-Ahead Market" to "in any power exchange market"	The PX and its markets are no longer operational; these changes are needed to accurately reflect the operation of the markets subsequent to the PX's stopping operations, and to implement changes to language in section to conform with similar changes in Section 2.2.12.2, *et seq.*, as approved in the proceeding concerning Amendment No. 56 to the ISO Tariff
2.2.12.2.3.1	Change "this Section 2.2.12.2.2" to "this Section 2.2.12.2.3"	Correct incorrect section reference
2.2.12.2.3.2	Change "the entire amount of RMR Energy" to "the entire amount of RMR Market Energy"; change "all remaining RMR Energy" to "all remaining RMR Market Energy"; change "Market Hour" to "hour" (3 places)	Implement changes to language in section to conform with similar changes in Section 2.2.12.2, *et seq.*, as approved in the proceeding concerning Amendment No. 56 to the ISO Tariff
2.2.12.2.3.2	Change "PX Market" to "power exchange market"	The PX and its markets are no longer operational; this change is needed to accurately reflect the operation of the markets subsequent to the PX's stopping operations, and to implement changes to language in section to conform with similar changes in Section 2.2.12.2, *et seq.*, as approved in the proceeding concerning Amendment No. 56 to the ISO Tariff
2.2.12.2.3.2.1	Change "include all RMR Energy" to "include all RMR Market Energy"; change "specify the RMR Energy" to "specify the RMR Market Energy"; change "Market Hour" to "hour" (4 places)	Implement changes to language in section to conform with similar changes in Section 2.2.12.2, *et seq.*, as approved in the proceeding concerning Amendment No. 56 to the ISO Tariff

Section	Change	Reason for Change
2.2.12.2.3.2.1	Change "PX Markets" to "power exchange markets" (2 places)	The PX and its markets are no longer operational; these changes are needed to accurately reflect the operation of the markets subsequent to the PX's stopping operations, and to implement changes to language in section to conform with similar changes in Section 2.2.12.2, *et seq.*, as approved in the proceeding concerning Amendment No. 56 to the ISO Tariff
2.2.12.2.3.3	Change "in Final Schedule" to "in a Final Schedule"	Correct a typographical error
2.2.12.2.3.3	Change "any source for RMR Energy" to "any source for RMR Market Energy"	Implement change to language in section to conform with similar changes to Section 2.2.12.2, *et seq.*, as approved in the proceeding concerning Amendment No. 56 to the ISO Tariff
2.2.12.3	Change "Non-PX Demand Information" to "Demand Information"; delete "(other than the PX)"	The PX and its markets are no longer operational; this change is needed to accurately reflect the operation of the markets subsequent to the PX's stopping operations
2.2.13.1	Change "Ancillary Services Bids" to "Ancillary Services bids"	Not a tariff-defined term
2.2.13.2.2	Change "Hour Ahead" to "Hour-Ahead"	Tariff-defined term incorrectly not hyphenated in section
2.2.17	Change "adjustment bids" to "Adjustment Bids"	Not capitalized in section, but is a tariff-defined term
2.2.17	Change "ISO protocols" to "ISO Protocols"	Not capitalized in section, but is a tariff-defined term
2.3.1.1.1	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.3.1.1.3	Change "subject to Section 2.3.1.2 to direct" to "subject to Section 2.3.1.2, to direct"	Correct grammar
2.3.1.1.6	Change "WSCC security coordinator" to "WECC reliability coordinator"	Update outdated reference to WSCC security coordinator
2.3.1.3.1	Change "reliability criteria" to "Reliability Criteria"	Not capitalized in section, but is a tariff-defined term

Section	Change	Reason for Change
2.3.1.3.1	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.3.1.3.2	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.3.2.2	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.3.2.3.2	Change "interruptible loads" to "interruptible Loads"	Change is made to reflect correct use of tariff-defined term Load
2.3.2.8.2	Change "self provision" to "self-provision"	Correct grammar
2.3.3.3	Change "Real Time" to "Real-Time"	Correct grammar
2.3.3.3	Change "real time" to "real-time"	Correct grammar
2.3.3.5	Change "planning procedure" to "Planning Procedure"	Not capitalized in section, but is a tariff-defined term
2.3.3.6	Change "ISO markets" to "ISO Markets"	Not capitalized in section, but is a tariff-defined term
2.3.3.9.5	Change "congestion" to "Congestion"	Not capitalized in section, but is a tariff-defined term
2.3.3.9.5	Change "operator" to "Operator"	Not capitalized in section, but is a tariff-defined term
2.3.4	Change "system emergency" to "System Emergency"	Not capitalized in section, but is a tariff-defined term
2.3.4	Change "operator" to "Operator"	Not capitalized in section, but is a tariff-defined term
2.3.5.1.2	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.3.5.1.2	Change "peak Load" to "peak Demand"	Correct incorrect use of defined term Load in place of defined term Demand
2.3.5.1.3	Change "Loads" to "Demands" (3 places)	The correct tariff-defined term to use in the context of the section is Demand rather than Load
2.3.5.1.3	Change "peak Load" to "peak Demand"	Correct incorrect use of defined term Load in place of defined term Demand
2.3.5.1.3	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.3.5.1.3	Change "Replacement Reserves" to "Replacement Reserve"	Tariff-defined term uses singular form for collective plural
2.3.5.1.4	Change "Replacement Reserves" to "Replacement Reserve"	Tariff-defined term uses singular form for collective plural
2.3.5.1.6	Change "peak loads" to	Correct incorrect use of word

Section	Change	Reason for Change
	"peak Demands"	"load" in place of defined term Demand
2.3.5.1.8	Change "Scheduling Coordiantor's" to "Scheduling Coordinator's"	Correct typographical error
2.4.4.1.1	Change "non-Participating TO" to "Non-Participating TO"	To conform with the tariff-defined term "Non-Participating TO"
2.5.1	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.5.1	Change "self provided" to "self-provided" (3 places)	Correct grammar
2.5.1	Change "dispatch" to "Dispatch"	Not capitalized in section, but is a tariff-defined term
2.5.1	Change "real time" to "real-time"	Correct grammar
2.5.1	Change "longer term" to "longer-term"	Correct grammar
2.5.2.1	Change "WSCC" to "WECC" (3 places)	Update outdated references to WSCC
2.5.2.2	Change "real time" to "real-time"	Correct grammar
2.5.2.2	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.5.2.2	Change "dispatch" to "Dispatch"	Not capitalized in section, but is a tariff-defined term
2.5.3.1	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.5.3.2	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.5.3.2	Change "Non-Spinning Reserves" to "Non-Spinning Reserve"	Tariff-defined term uses singular form for collective plural
2.5.3.4	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.5.3.4	Change "voltage support" to "Voltage Support"	Not capitalized in section, but is a tariff-defined term
2.5.3.5(b)	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.5.3.5(b)	Change "system load level" to "system Demand level"	The correct tariff-defined term to use in the context of the section is Demand rather than Load
2.5.5	Change "system reliability" to "System Reliability"	Not capitalized in section, but is a tariff-defined term
2.5.5	Change "long term" to "long-term"	Correct grammar
2.5.5	Change "longer term" to	Correct grammar

Section	Change	Reason for Change
	"longer-term"	
2.5.6	Change "schedule" to "Schedule"	Not capitalized in section, but is a tariff-defined term
2.5.6	Change "self provision" to "self-provision"	Correct grammar
2.5.7.3	Change "found in Section 2.5.27.7 of this Tariff" to "found in this ISO Tariff"	Remove reference Section 2.5.27.7, which is "not used"; make tariff reference more specific
2.5.7.3	Change "market clearing price" to "Market Clearing Price"	Not capitalized in section, but is a tariff-defined term
2.5.7.3	Change "Market Based" to "Market-Based"; change "market based" to "market-based"	Correct grammar
2.5.7.4.2	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.5.7.4.3	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.5.7.4.4	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.5.7.4.5	Change "section 2.5.7.4" to "Section 2.5.7.4"	Internal section references in the tariff/protocols are capitalized
2.5.8	Change "Hour-Ahead market" to "Hour-Ahead Market"	Not capitalized in section, but is a tariff-defined term
2.5.8	Change "system reliability" to "System Reliability"	Not capitalized in section, but is a tariff-defined term
2.5.10.2	Change "section 2.5.21" to "Section 2.5.21"	Internal section references in the tariff/protocols are capitalized
2.5.12(e)	Change "Day Ahead Market" to "Day-Ahead Market"	Tariff-defined term incorrectly not hyphenated in section
2.5.13	Change "real time" to "real-time"	Correct grammar
2.5.14	Change "zone" to "Zone"	Not capitalized in section, but is a tariff-defined term
2.5.14	Change "zonal" to "Zonal"	Not capitalized in section, but is a tariff-defined term
2.5.14	Change "market clearing price" to "Market Clearing Price"	Not capitalized in section, but is a tariff-defined term
2.5.14	Change "zonal market clearing (MCP_{xt}) price" to "Zonal Market Clearing Price (MCP_{xt})"	Capitalize tariff-defined terms, and put words in the proper order

Section	Change	Reason for Change
2.5.14(f)	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.5.15	Change "zone" to "Zone"	Not capitalized in section, but is a tariff-defined term
2.5.15	Change "zonal" to "Zonal" (2 places)	Not capitalized in section, but is a tariff-defined term
2.5.15	Change "System resources" to "System Resources"	Not capitalized in section, but is a tariff-defined term
2.5.15	Change "Spinning reserve" to "Spinning Reserve"	Not capitalized in section, but is a tariff-defined term
2.5.15	Change "market clearing price" to "Market Clearing Price" (2 places)	Not capitalized in section, but is a tariff-defined term
2.5.16	Change "zone" to "Zone"	Not capitalized in section, but is a tariff-defined term
2.5.16	Change "zonal" to "Zonal" (2 places)	Not capitalized in section, but is a tariff-defined term
2.5.16	Change "market clearing price" to "Market Clearing Price" (2 places)	Not capitalized in section, but is a tariff-defined term
2.5.17	Change "section 2.5.21" to "Section 2.5.21"	Internal section references in the tariff/protocols are capitalized
2.5.17	Change "zone" to "Zone"	Not capitalized in section, but is a tariff-defined term
2.5.17	Change "zonal" to "Zonal" (2 places)	Not capitalized in section, but is a tariff-defined term
2.5.17	Change "market clearing price" to "Market Clearing Price" (2 places)	Not capitalized in section, but is a tariff-defined term
2.5.18	Change "cost based" to "cost-based" (2 places)	Correct grammar
2.5.18	Change "Reliability Must-Run units" to "Reliability Must-Run Units"	Not capitalized in section, but is a tariff-defined term
2.5.18	Change "long term" to "long-term"	Correct grammar
2.5.20	Change "Self Provision" to "Self-Provision"	Correct grammar
2.5.20.1	Change "real time" to "real-time"	Correct grammar
2.5.20.2	Change "Self Provide" to "Self-Provide"	Correct grammar
2.5.20.2	Change "self provide" to "self-provide"	Correct grammar
2.5.20.2	Change "self provides" to "self-provides"	Correct grammar
2.5.20.2	Change "self provided" to	Correct grammar

Section	Change	Reason for Change
	"self-provided" (2 places)	
2.5.20.2	Change "schedule" to "Schedule"	Not capitalized in section, but is a tariff-defined term
2.5.20.4	Change "Self Provided" to "Self-Provided"	Correct grammar
2.5.20.4	Change "self provide" to "self-provide"	Correct grammar
2.5.20.5	Change "Self Provision" to "Self-Provision"	Correct grammar
2.5.20.5.1	Change "self provision" to "self-provision"	Correct grammar
2.5.20.5.1	Change "self provided" to "self-provided"	Correct grammar
2.5.20.6	Change "self provided" to "self-provided"	Correct grammar
2.5.20.7	Change "Self Provided" to Self-Provided"	Correct grammar
2.5.20.7	Change "schedules" to "Schedules" (2 places)	Not capitalized in section, but is a tariff-defined term
2.5.20.7	Change "self provided" to "self-provided" (2 places)	Correct grammar
2.5.21	Change "zone" to "Zone" (2 places)	Not capitalized in section, but is a tariff-defined term
2.5.21	Change "zonal" to "Zonal"	Not capitalized in section, but is a tariff-defined term
2.5.21	Change "Hour-Ahead schedules" to "Hour-Ahead Schedules"	Not capitalized in section, but is a tariff-defined term
2.5.21	Change "self provided" to "self-provided"	Correct grammar
2.5.22	Change "Real Time" to "Real-Time"	Correct grammar
2.5.22.2	Change "real time" to "real-time"	Correct grammar
2.5.22.2	Change "dispatch" to "Dispatch"	Not capitalized in section, but is a tariff-defined term
2.5.22.2(a)	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.5.22.2(b)	Change "forecasted load" to "forecasted Demand"	The correct tariff-defined term to use in the context of the section is Demand
2.5.22.2(c), -(d)	Change "constraints" to "Constraints"	Not capitalized in section, but is a tariff-defined term
2.5.22.3	Change "WSCC" to "WECC"	Update outdated reference to WSCC
2.5.22.3	Change "self provided" to "self-provided"	Correct grammar
2.5.22.3.2	Change "Self Provided" to "Self-Provided"	Correct grammar

Section	Change	Reason for Change
2.5.22.3.2	Change "self provide" to "self-provide"	Correct grammar
2.5.22.3.2	Change "self provided" to "self-provided"	Correct grammar
2.5.22.4	Change "Hour-Ahead markets" to "Hour-Ahead Markets"	Not capitalized in section, but is a tariff-defined term
2.5.22.6	Change "Real Time" to "Real-Time"	Correct grammar
2.5.22.6	Change "each Generating Unit, Load, System Unit or System Resource" to "each Generating Unit, Curtailable Demand, System Unit or System Resource"	To remove incorrect reference to Load
2.5.22.6.2	Change "zone" to "Zone" (2 places)	Not capitalized in section, but is a tariff-defined term
2.5.22.6.2	Change "control area" to "Control Area"	Not capitalized in section, but is a tariff-defined term
2.5.22.6.2	Change "zones" to "Zones"	Not capitalized in section, but is a tariff-defined term
2.5.22.6.2	Change "zonal" to "Zonal" (5 places)	Not capitalized in section, but is a tariff-defined term
2.5.22.6.2(a)	Change "dispatch" to "Dispatch"	Not capitalized in section, but is a tariff-defined term
2.5.22.6.3	Change "Real Time" to "Real-Time"; change "Real Time" to "Real-time"; change "Real Time" to "real-time"	Correct grammar
2.5.22.6.4	Change "Real Time" to "Real-Time"; change "Real Time" to "Real-time"	Correct grammar
2.5.22.11	Change "self provided" to "self-provided" (2 places)	Correct grammar
2.5.23.1	Change "supply" to "Supply" (2 places)	Not capitalized in section, but is a tariff-defined term
2.5.23.1	Change "Dispatch Instructions" to "Dispatch instructions" (2 places)	In context of the section, instructions should be in lower case
2.5.23.2.2	Change "real time" to "real-time"	Correct grammar
2.5.23.2.2	Change "load shedding" to "Load Shedding"	Not capitalized in section, but is a tariff-defined term
2.5.23.2.2	Change "Imbalance energy" to "Imbalance Energy"	Not capitalized in section, but is a tariff-defined term

Section	Change	Reason for Change
2.5.23.2.3	Change "zonal" to "Zonal"	Not capitalized in section, but is a tariff-defined term
2.5.23.3.3	Change "minimum Load" to "minimum load"	In context of sentence, load should not be capitalized
2.5.23.3.6.6	Change "generating unit" to "Generating Unit"	Not capitalized in section, but is a tariff-defined term
2.5.24	Change "self provided" to "self-provided" (2 places)	Correct grammar
2.5.24	Change "self providers" to "self-providers"	Correct grammar
2.5.25.2	Change "Generating Unit ," to "Generating Unit,"	Remove extra space between words
2.5.26.1	Change "self provision" to "self-provision" (2 places)	Correct grammar
2.5.26.2.3	Change "Replacement reserve" to "Replacement Reserve"	Not capitalized in section, but is a tariff-defined term
2.5.26.2.6	Change "Dispatch instruction" to "Dispatch Instruction"	Not capitalized in section, but is a tariff-defined term
2.5.26.3	Change "Day Ahead and Hour Ahead" to "Day-Ahead and Hour-Ahead"	Tariff-defined terms incorrectly not hyphenated in section
2.5.26.3	Change "Dispatch instruction" to "Dispatch Instruction" (2 places)	Not capitalized in section, but is a tariff-defined term
2.5.26.5	Un-bold the "I" in "If"	Correct incorrect use of bolded text
2.5.26.5	Change "WSCC" to WECC" (2 places)	Update outdated reference to WSCC
2.5.27	Change "WSCC" to "WECC" (2 places)	Update outdated reference to WSCC
2.5.27	Change "Hour-Ahead markets" to "Hour-Ahead Markets"	Not capitalized in section, but is a tariff-defined term
2.5.27.1	Change "real time" to "real-time"	Correct grammar
2.5.27.1	Delete "at bids at or below the level specified in Section 2.5.27.7" in the second and third paragraphs of the "Quantities" subsection and "for bids at or below the level specified in Section 2.5.27.7 and prices determined in accordance with Section	Referenced Section 2.5.27.7 has been deleted

Section	Change	Reason for Change
	2.5.27.7 for bids above that level" in the first paragraph of the "Prices" subsection	
2.5.27.1	Change "WSCC" to "WECC" (2 places)	Update outdated reference to WSCC
2.5.27.1	Change "market clearing price" to "Market Clearing Price" (2 places)	Not capitalized in section, but is a tariff-defined term
2.5.27.1	Change "Day-Ahead market" to "Day-Ahead Market" (2 places)	Not capitalized in section, but is a tariff-defined term
2.5.27.2	Change "real time" to "real-time"	Correct grammar
2.5.27.2	Delete "at bids at or below the level specified in Section 2.5.27.7" in the second paragraph of the "Quantities" subsection and "for bids at or below the level specified in Section 2.5.27.7 and prices determined in accordance with Section 2.5.27.7 for bids above that level" in the first paragraph of the "Prices" subsection	Referenced Section 2.5.27.7 has been deleted
2.5.27.2	Change "ISO protocols" to "ISO Protocols"	Not capitalized in section, but is a tariff-defined term
2.5.27.2	Change "market clearing price" to "Market Clearing Price"	Not capitalized in section, but is a tariff-defined term
2.5.27.3	Change "section 2.5.26.1" to "Section 2.5.26.1"	Internal section references in the tariff/protocols are capitalized
2.5.27.3	Change "real time" to "real-time"	Correct grammar
2.5.27.3	Delete "at bids at or below the level specified in Section 2.5.27.7" in the second paragraph of the "Quantities" subsection and "for bids at or below the level specified in Section 2.5.27.7 and prices determined in accordance with Section 2.5.27.7 for bids above that level" in the first	Referenced Section 2.5.27.7 has been deleted

Section	Change	Reason for Change
	paragraph of the "Prices" subsection	
2.5.27.3	Change "ISO protocols" to "ISO Protocols"	Not capitalized in section, but is a tariff-defined term
2.5.27.3	Change "settlement" to "Settlement"	Not capitalized in section, but is a tariff-defined term
2.5.27.3	Change "market clearing price" to "Market Clearing Price"	Not capitalized in section, but is a tariff-defined term
2.5.27.4	Change "section 2.5.17" to "Section 2.5.17"	Internal section references in the tariff/protocols are capitalized
2.5.27.4	Change "section 2.5.26.1" to "Section 2.5.26.1"	Internal section references in the tariff/protocols are capitalized
2.5.27.4	Change "real time" to "real-time"	Correct grammar
2.5.27.4	Delete "at bids at or below the level specified in Section 2.5.27.7" in the second paragraph of the "Quantities" subsection" and "for bids at or below the level specified in Section 2.5.27.7 and prices determined in accordance with Section 2.5.27.7 for bids above that level" in the first paragraph of the "Prices" subsection	Referenced Section 2.5.27.7 has been deleted
2.5.27.4	Change "ISO protocols" to "ISO Protocols"	Not capitalized in section, but is a tariff-defined term
2.5.27.4	Change "settlement" to "Settlement" (2 places)	Not capitalized in section, but is a tariff-defined term
2.5.27.4	Change "market clearing price" to "Market Clearing Price"	Not capitalized in section, but is a tariff-defined term
2.5.27.4	Change "suppplied" to "supplied"	Correct typographical error
2.5.27.5	Change "long term" to "long-term"	Correct grammar
2.5.27.6	Change "section 2.5.19" to "Section 2.5.19"	Internal section references in the tariff/protocols are capitalized
2.5.27.6	Change "section 2.5.26.1" to "Section 2.5.26.1"	Internal section references in the tariff/protocols are capitalized
2.5.27.6	Change "Interim Black Start agreement" to "Interim Black Start Agreement"	Reflect name of specific agreement

Section	Change	Reason for Change
2.5.28	Replace "Sections 2.5.28" with "Sections 2.5.28.5 and 2.5.28.6"	Reference to "Sections 2.5.28" regarding Voltage Support and Black Start should be to Sections 2.5.28.5 and 2.5.28.6
2.5.28	Change "Hour-Ahead markets" to "Hour-Ahead Markets"	Not capitalized in section, but is a tariff-defined term
2.5.28	Change "self provided" to "self-provided" (2 places)	Correct grammar
2.5.28	Change "Day-Ahead market" to "Day-Ahead Market"	Not capitalized in section, but is a tariff-defined term
2.5.28.1	Change "self provided" to "self-provided" (5 places)	Correct grammar
2.5.28.2	Change "self provided" to "self-provided"	Correct grammar
2.5.28.3	Change "self provided" to "self-provided" (2 places)	Correct grammar
2.5.28.4	Change "zone" to "Zone"	Not capitalized in section, but is a tariff-defined term
2.5.28.4	Change "self provision" to "self-provision"	Correct grammar
2.5.28.5	Change "short term" to "short-term" (4 places)	Correct grammar
2.5.28.5	Change "long term" to "long-term" (5 places)	Correct grammar
2.5.28.6	Remove "in accordance with Section 3.3.4.5"	Referenced Section 3.3.4.5 is no longer in use
2.5.29	Change "Non-spinning Reserve" to Non-Spinning Reserve	To conform with the tariff-defined term "Non-Spinning Reserve"
3.2.1	Change "system reliability" to "System Reliability"	Not capitalized in section, but is a tariff-defined term
3.2.1.2	Change "WSCC" to "WECC" (2 places)	Update outdated reference to WSCC
3.2.1.2	Change "system reliability" to "System Reliability"	Not capitalized in section, but is a tariff-defined term
3.2.1.2	Change "reliability criteria" to "Reliability Criteria"	Not capitalized in section, but is a tariff-defined term
3.2.2.3	Change "WSCC" to "WECC"	Update outdated reference to WSCC
3.2.2.4	Change "No Participating TO, Market Participant nor the ISO" to "Neither the ISO nor any Participating TO nor any Market Participant"	Correct grammar

Section	Change	Reason for Change
3.2.2.4	Change "WSCC" to "WECC" (3 places)	Update outdated reference to WSCC
3.2.6	Change "WSCC" to "WECC" (2 places)	Update outdated reference to WSCC
4.1.2	Change "distribution system" to "Distribution System"	Not capitalized in section, but is a tariff-defined term
4.2	Change "maintenance Outage" to "Maintenance Outage"	Not capitalized in section, but is a tariff-defined term
4.5.3.1	Change "Day Ahead" to "Day-Ahead"	Tariff-defined term incorrectly not hyphenated in section
4.5.3.2	Change "Hour Ahead to "Hour-Ahead"	Tariff-defined term incorrectly not hyphenated in section
4.8.1	Change "system planning studies" to "System Planning Studies"	Not capitalized in section, but is a tariff-defined term
5.2.1.2	Change "Must-Run Unit's" to "Reliability Must-Run Unit's"	Conform with tariff-defined term
5.2.5	Change "Reliability Must-Run contract" to "Reliability Must-Run Contract"	Not capitalized in section, but is a tariff-defined term
5.2.6	Change "Reliability Must-Run contracts" to "Reliability Must-Run Contracts"	Not capitalized in section, but is a tariff-defined term
5.2.7.1.1	Change "Reliability Must-run contract" to "Reliability Must-Run Contract"	Not capitalized in section, but is a tariff-defined term
5.2.7.1.3	Replace "Section 5.27" with "Section 5.2.7"	Correct incorrect section reference
5.2.7.1.3	Change "ISO Governing board" to "ISO Governing Board"	Not capitalized in section, but is a tariff-defined term
5.4	Change "WSCC" to "WECC"	Update outdated reference to WSCC
5.4.1	Change "WSCC" to "WECC"	Update outdated reference to WSCC
5.4.2	Change "WSCC" to "WECC"	Update outdated reference to WSCC
5.4.2	Change "reliability criteria" to "Reliability Criteria"	Not capitalized in section, but is a tariff-defined term
5.4.3	Change "WSCC" to "WECC" (2 places)	Update outdated references to WSCC
5.5.2	Change "congestion" to "Congestion"	Not capitalized in section, but is a tariff-defined term

Section	Change	Reason for Change
5.7.4.2.1	Change "Calendar Days" to "calendar days" (2 places)	Not a tariff-defined term
5.7.4.2.2	Change "Calendar Days" to "calendar days" (2 places)	Not a tariff-defined term
5.7.4.2.2	Change "POT" to "PTO"	Correct typographical error in use of tariff-defined term
5.7.4.2.2	Change "New Facility operator's" to "New Facility Operator's"	To conform with the tariff-defined term "New Facility Operator"
5.7.4.3	Add "and 5.7.4.2.2" after "Sections 5.7.4.2.1"	Reference to "Sections 5.7.4.2.1" should it be corrected to refer to Section 5.7.4.2.2 as well
5.7.4.4.1(a)	Change "§2.20" to "§ 2.20"	Insert needed space
5.7.4.4.1(a)	Change "TO tariff" to "TO Tariff"	Not capitalized in section, but is a tariff-defined term
5.7.6	Change "this Section 5.2" to "this Section 5.7"	Correct incorrect section reference
5.9	Change "subsection 5.4 hereof" to "Section 5.4 of this ISO Tariff"	Reference to "subsection 5.4 hereof" should be clarified, and internal section references in the tariff/protocols are capitalized
5.11.2	Change "self provision" to "self-provision"	Correct grammar
5.11.6	Change "Hour-Ahead market" to "Hour-Ahead Market"	Not capitalized in section, but is a tariff-defined term
5.11.6	Change "generating unit" to "Generating Unit" (3 places); change "generating units" to "Generating Units" (2 places)	Not capitalized in section, but is a tariff-defined term
5.11.6	Change "Must-Offer Obligation" to "must-offer obligation"	Non-defined term is capitalized
5.11.6	Change "operating reserve" to "Operating Reserve"	Not capitalized in section, but is a tariff-defined term
5.11.6	Change "Day-Ahead Energy Schedules" to "Day-Ahead Schedules for Energy"	Proper use of tariff-defined terms
5.11.6.1.1	Change "Hour-Ahead market" to "Hour-Ahead Market"	Not capitalized in section, but is a tariff-defined term
5.11.6.1.1	Change "generating unit"	Not capitalized in section, but is a

Section	Change	Reason for Change
	to "Generating Unit"	tariff-defined term
5.11.6.1.1	Change "Minimum Load" to "minimum load" (5 places)	Not a tariff-defined term
5.11.6.1.1	Change "Real-time" to "real time"	Correct grammar
5.11.6.1.1	Change "Real-time" to "real-time"	Correct grammar
5.11.6.1.1	Change "Compensation" to "compensation"	Not a tariff-defined term
5.11.6.1.1	Change "Must-Offer Obligation" to "must-offer obligation" (2 places)	Non-defined term is capitalized
5.11.6.1.1	Change "Ex Post price" to "Ex Post Price"	Not capitalized in section, but is a tariff-defined term
5.11.6.1.3	Change "business days" to "Business Days"	Not capitalized in section, but is a tariff-defined term
5.11.6.1.3	Change "Invoice" to "invoice"	Not a tariff-defined term
5.11.6.1.5	Change "Minimum Load" to "minimum load"	Correct incorrect capitalization
5.11.6.1.5	Change "Compensation" to "compensation"	Not a tariff-defined term
5.13.1	Change "Real Time Imbalance Energy Market" to "real-time Imbalance Energy market"	Correct capitalization of term
5.13.1	Change "Real-Time Hourly Pre-Dispatch" to "real-time Hourly Pre-Dispatch"	Correct capitalization of terms
5.13.2.1	Change "Real-Time Hourly Pre-Dispatch" to "real-time Hourly Pre-Dispatch"	Correct capitalization of terms
5.13.2.2	Change "Real-time" to "Real-Time"	Correct grammar
5.13.3	Change "Real Time Imbalance Energy Market" to "real-time Imbalance Energy market" (2 places)	Correct capitalization of terms
6.1.2.2.2(d)	Change ";Total" to "; Total"	Add space where needed
6.1.2.5(f)	Change "regulation requirements" to "Regulation requirements"	Not capitalized in section, but is a tariff-defined term

Section	Change	Reason for Change
7.2.1.2	Delete ", as described in Section 7.2.7.1"	Referenced Section 7.2.7.1 itself references Appendix I
7.2.1.3	Change "constraints" to "Constraints"	Not capitalized in section, but is a tariff-defined term
7.2.1.5	Change "Real Time" to "Real-Time"	Correct grammar
7.2.4.1.4	Change "real time" to "real-time"	Correct grammar
7.2.4.2.7	Change "Inter-SC Trades" to "inter-Scheduling Coordinator trades"	To correct use of term that is not a tariff-defined term
7.2.5.2.2	Change "redispatch costs" to "Redispatch costs"	Not capitalized in section, but is a tariff-defined term
7.2.5.2.8 (The second section number identified as 7.2.5.2.8)	Change "7.2.5.2.8" to "7.2.5.2.9"	Correct section numbering
7.2.6.1	Change "redispatch" to "Redispatch"; change "redispatching" to "Redispatching"	Not capitalized in section, but is a tariff-defined term
7.2.6.1	Change "themal" to "thermal"	Correct misspelling
7.2.6.1.1(a)(4)	Change "zone" to "Zone"	Not capitalized in section, but is a tariff-defined term
7.2.6.2	Delete "2.4.2 and"	Referenced Section 2.4.2 has been deleted
7.2.6.2	Change "redispatch" to "Redispatch"	Not capitalized in section, but is a tariff-defined term
7.3.1.3.3	Change "section 7.3.1.3.2" to "Section 7.3.1.3.2"	Internal section references in the tariff/protocols are capitalized
7.3.1.5.2	Change "real time" to "real-time" (2 places)	Correct grammar
7.3.1.7	Change "outage" to "Outage"	Not capitalized in section, but is a tariff-defined term
7.3.2	Change "redispatched" to "Redispatched"; change "redispatch cost" to "Redispatch cost"	Not capitalized in section, but is a tariff-defined term
7.4.1	Change "Market" to "market"	Not a tariff-defined term
7.4.1	Change "Real Time" to "real time"	Correct grammar
7.4.1	Change "transmission losses" to "Transmission Losses" (3 places)	Not capitalized in section, but is a tariff-defined term
7.4.2.1.2	Change "real time" to "real-time"	Correct grammar
8.3.1	Change "demand" to	Not capitalized in section, but is a

Section	Change	Reason for Change
	"Demand" (2 places)	tariff-defined term
8.3.2	Change "megawatt hours" to "megawatt-hours"	Hyphenate words so that term reads correctly
8.3.3	Change "settlement interval" to "Settlement Interval" (2 places)	Not capitalized in section, but is a tariff-defined term
8.3.6	Change "settlement interval" to "Settlement Interval"	Not capitalized in section, but is a tariff-defined term
9.1.1	Change "congestion" to "Congestion"	Not capitalized in section, but is a tariff-defined term
9.3.1(i)	Change "WSCC" to "WECC" (2 places)	Update outdated references to WSCC
9.3.1(i)	Change "WSCC's" to "WECC's"	Update outdated reference to WSCC
9.4.2.3	Change "FTR market" to "FTR Market"	Not capitalized in section, but is a tariff-defined term
9.4.2.4	Change "FTR market" to "FTR Market"	Not capitalized in section, but is a tariff-defined term
9.4.2.7	Change ". FTR Bidders" to ". FTR Bidders"	Delete extra space after period
9.4.2.7	Change "business days" to "Business Days"	Not capitalized in section, but is a tariff-defined term
9.4.2.7	Change "9.4.2.7" to "9.2.6"	Correct incorrect section reference
9.6.2	Change "FTR holder" to "FTR Holder"	Not capitalized in section, but is a tariff-defined term
9.6.3	Change "FTR market" to "FTR Market"	Not capitalized in section, but is a tariff-defined term
9.6.3	Change "Day Ahead" to "Day-Ahead" (2 places)	Tariff-defined term incorrectly not hyphenated in section
9.6.4	Change "congestion" to "Congestion"	Not capitalized in section, but is a tariff-defined term
9.6.5	Change "congestion" to "Congestion"	Not capitalized in section, but is a tariff-defined term
9.7.1	Change "real time" to "real-time"	Correct grammar
9.7.1	Change "trading day" to "Trading Day"	Not capitalized in section, but is a tariff-defined term
9.7.2.1	Change "schedules" to "Schedules" (2 places)	Not capitalized in section, but is a tariff-defined term
9.7.3	Change "FTR holders" to "FTR Holders"	Not capitalized in section, but is a tariff-defined term
9.8.1	Change "section 9.7" to "Section 9.7"	Internal section references in the tariff/protocols are capitalized
9.8.1	Change "business days" to "Business Days"	Not capitalized in section, but is a tariff-defined term
9.8.2	Change "ISO Board of Governors" to "ISO	Tariff-defined term is ISO Governing Board

Section	Change	Reason for Change
	Governing Board"	
10	Change "10.METERING" to "10. METERING"	Provide proper spacing in section title
10.1	Put section heading in boldface type, and move rest of text of section below section heading	Correct format of section heading and text of section
10.2.1	Change "meter data" to "Meter Data"	Not capitalized in section, but is a tariff-defined term
10.2.1	Change "metering protocols" to "metering protocols"	Remove extra space between words
10.2.1	Change "interconnectins" to "interconnections"	Correct typographical error
10.2.2	Change "real time" to "real-time"	Correct grammar
10.2.4	Change "ISO shall" to "ISO shall"	Remove extra space between words
10.2.5	Change "metering protocols" to "metering protocols"	Remove extra space between words
10.2.5	Change "for example, ," to "for example,"	Correct typographical error
10.3.2	Change "Tie-Point Meters" to "Tie Point Meters"	Tariff-defined term is not hyphenated
10.6.7.7	Change "meter data" to "Meter Data" (2 places)	Not capitalized in section, but is a tariff-defined term
11.2	Change "accordanc e" to "accordance"	Remove extra space within word
11.2.4	Change "final Hour-Ahead Schedule" to "Final Hour-Ahead Schedule"	Not capitalized in section, but is a tariff-defined term
11.2.4	Change "Dispatch instructions" to "Dispatch Instructions" (3 places)	Not capitalized in section, but is a tariff-defined term
11.2.4.1.1.1	Change "Curtailable Load" to "Curtailable Demand"	Change section title to reflect correction of incorrect reference to Curtailable Load
11.2.4.1.1.1	Change "each Generating Unit, System Unit and Curtailable Load" to "each Generating Unit, System Unit and Curtailable Demand"	To correct incorrect reference to Curtailable Load
11.2.4.1.1.1	Change "Real-Time Market" to "Real Time Market	Tariff-defined term is not hyphenated
11.2.4.1.1.2	Change "costs. This" to	Remove extra space after period

Section	Change	Reason for Change
	"costs. This"	
11.2.4.1.1.2	Change "Real-Time Market" to "Real Time Market	Tariff-defined term is not hyphenated
11.2.4.1.2	Change "final Hour-Ahead Schedule" to "Final Hour-Ahead Schedule"	Not capitalized in section, but is a tariff-defined term
11.2.4.1.2	Change "ramping" to "Ramping"	Not capitalized in section, but is a tariff-defined term
11.2.4.1.2	Change "Pre-Dispatch" to "pre-Dispatch" (2 places)	Correct grammar
11.2.4.1.2(a)	Change "Staged" to "staged"	Term should not be capitalized
11.2.4.1.2(b)	Change "Pre-Dispatched" to "pre-Dispatched" (2 places)	Correct grammar
11.2.4.1.2(e)	Change "Qualifying Facilities" to "Qualifying Facilities (QFs)"	Provide abbreviation for Qualifying Facilities
11.2.4.1.2(e)	Change "Commission" to "FERC"	FERC is the tariff-defined term
11.2.4.1.2(f)	Change "Deviation Penalties" to "deviation penalties"	To correct incorrectly capitalized term, and eliminate possible confusion caused by use of term which is phrased similarly to the tariff-defined term Uninstructed Deviation Penalty
11.2.4.1.2(f)	Change "transmission losses" to "Transmission Losses"	Not capitalized in section, but is a tariff-defined term
11.2.4.1.2(g)	Change "Uninstructed Deviations" to "uninstructed deviations"	Not a tariff-defined term
11.2.4.1.2(h)	Change "Uninstructed Deviations" to "uninstructed deviations" (2 places); change "Uninstructed Deviations" to "Uninstructed deviations"	Not a tariff-defined term
11.2.4.1.2(h)	Change "aggravated" to "aggregated"	Use correct word in sentence
11.2.4.1.2(o)	Change "Out of Market" to "out-of-market"	Correct grammar; not a tariff-defined term
11.2.4.1.2(o)	Change "control area" to "Control Area"	Not capitalized in section, but is a tariff-defined term
11.2.4.1.2(o)	Change "Pre-Dispatch" to "pre-Dispatch"	Correct grammar

Section	Change	Reason for Change
11.2.4.1.2(p)	Change "2.3.3.9.2" to "2.3.3.9.5"	Correct incorrect reference to Section 2.3.3.9.2
11.2.4.1.2(q)	Change "Existing Transmission Contracts" to "Existing Contracts"	The tariff-defined term is Existing Contracts
11.2.4.2	Change "Section 11.2.4.1" to "the payment option described in Section 11.2.4.2(a)"	Correct incorrect section reference
11.2.4.2(a)	Change "Charge" to "charge"	Not a tariff-defined term
11.2.4.2(a)	Change "Section 11.2.4.1" to "Section 2.5.23.2.2"	Correct incorrect section reference
11.2.4.2(b)(i)(ii)	Change "dispatch instruction" to "Dispatch Instruction" (3 places)	Not capitalized in section, but is a tariff-defined term
11.2.4.2(b)(ii)	Delete "PX Day-Ahead, PX Hour-Ahead and"	The PX and its markets are no longer operational
11.2.4.2(b)(ii)	Change "start-up fuel costs" to "Start-Up Fuel Costs" (2 places)	Not capitalized in section, but is a tariff-defined term
11.2.4.2(b)(ii)	Change "Real-Time Market" to "Real Time Market"	Tariff-defined term is not hyphenated
11.2.4.2.1	Change "Real-Time" to "real-time"	Correct grammar
11.2.4.2.1	Change "outage" to "Outage" (2 places);	Not capitalized in section, but is a tariff-defined term
11.2.4.2.1	Change "Imbalance energy" to "Imbalance Energy"	Not capitalized in section, but is a tariff-defined term
11.2.4.2.2.1	Change "or a" to "or a"	Remove extra space between words
11.2.4.2.2.1	Change "Exports" to "exports"	Not a tariff-defined term
11.2.4.2.2.1	Change "System" to "system"	Not a tariff-defined term
11.2.4.2.2.1	Change "net negative Uninstructed Deviation" to "Net Negative Uninstructed Deviation"	Not capitalized in section, but is a tariff-defined term
11.2.4.2.2.1	Change "outage" to "Outage"	Not capitalized in section, but is a tariff-defined term
11.2.4.5.1	Change "above- referenced" to "above-referenced"	Remove extra space between hyphenated words
11.2.4.5.1	Change "transmission losses" to "Transmission	Not capitalized in section, but is a tariff-defined term

Section	Change	Reason for Change
	Losses"	
11.2.4.5.3	Change "Settlement Interval Ex Post Price specified in Section 2.5.23.2.1" to "Dispatch Interval Ex Post Price"	Correct use of tariff-defined term
11.3.2	Change "long term" to "long-term"	Correct grammar
11.5	Change "Data ." to "Data."	Remove extra space
11.6.3	Change "Settlement Statement re-run" to "Settlement Statement Re-run" (3 places); change "Settlement Statement re-runs" to "Settlement Statement Re-runs" (2 places)	Not capitalized in section, but is a tariff-defined term
11.6.3.1	Change "Settlement Statement re-run" to "Settlement Statement Re-run" (2 places)	Not capitalized in section, but is a tariff-defined term
11.6.3.2	Change "Settlement Statement re-run" to "Settlement Statement Re-run" (2 places)	Not capitalized in section, but is a tariff-defined term
11.6.3.2	Change "Governing Board" to "ISO Governing Board"	Tariff-defined term is ISO Governing Board
11.6.3.3	Change "Settlement Statement re-run" to "Settlement Statement Re-run" (2 places)	Not capitalized in section, but is a tariff-defined term
11.21.1(c)	Change "meter data" to "Meter Data"	Not capitalized in section, but is a tariff-defined term
11.21.1(c)	Change "Settlement Runs" to "Settlement runs"	Correct capitalization of term.
13.2.4	Change "WSCC" to "WECC"	Update outdated reference to WSCC
20.3.1	Change "Wenet" to "WENet"	Correct use of tariff-defined term
20.3.2	Change "short-term" to "short term"	Correct grammar
21.1	Change "the PX and all other" to "all"	The PX and its markets are no longer operational
21.2.1	Delete ", except the PX,"	The PX and its markets are no longer operational
21.2.1	Change "schedules" to "Schedules"	Not capitalized in section, but is a tariff-defined term

Section	Change	Reason for Change
21.2.2	Delete section	The PX and its markets are no longer operational, and thus the provisions in this section are inapplicable
23	Change "Metered Subsystems" to "METERED SUBSYSTEMS"	Section heading should be in all capital letters
23.4.6	Change "zone" to "Zone"	Not capitalized in section, but is a tariff-defined term
23.5.2	Change "schedules" to "Schedules"	Not capitalized in section, but is a tariff-defined term
23.5.2	Change "Load" to "Demand"	The correct tariff-defined term to use in the context of the section is Demand rather than Load
23.12.2	Change "ex post price" to "Ex Post Price"	Not capitalized in section, but is a tariff-defined term
23.12.3.3	Change "(the Ancillary Services and Real-Time Energy Operations Charge (ASREO) will be treated on a net basis" to "(the Ancillary Services and Real-Time Energy Operations Charge (ASREO)) will be treated on a net basis"	Close parenthesis following "(ASREO)"
23.13.1	Change "Demand forecasts" to "Demand Forecasts"	Not capitalized in section, but is a tariff-defined term
23.13.3	Change "23.13.3" to "23.13.3.5"	Correct section numbering
23.16.4	Change "transmission losses" to "Transmission Losses" (2 places)	Not capitalized in section, but is a tariff-defined term
28.1.3	Change "market clearing price" to "Market Clearing Price"	Not capitalized in section, but is a tariff-defined term
30.3	Change "business day" to "Business Day"; change "business days" to "Business Days"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Actual Imbalance"	Delete defined term	Term is defined but not used in the tariff/protocols
Appendix A, at defined term "Adjustment Bid"	Change "Inter-SC Trade" to "inter-Scheduling Coordinator trade" (2 places)	To correct use of term that is not a tariff-defined term
Appendix A, at defined	Delete defined term	Term is defined but not used in

Section	Change	Reason for Change
term "Aggregate Final Accepted Schedules"		the tariff/protocols
Appendix A, at defined term "Applicable Reliability Criteria"	Change "WSCC" to "WECC"	Update outdated reference to WSCC
Appendix A, definition of "Approved Credit Rating"	Remove references to "D1 by Duff & Phelps Credit Rating Agency," "D2 by Duff & Phelps Credit Rating Agency," and "A- by Duff & Phelps Credit Rating Agency"; replace "Fitch IBCA Incorporated" with "Fitch Ratings" (5 places); renumber references in definition accordingly	To delete reference to a firm that no longer exists, and to update the name of an existing firm
Appendix A, at defined term "Approved Credit Rating"	Change "ISO Board of Governors" to "ISO Governing Board"	Tariff-defined term is ISO Governing Board
Appendix A, at defined term "Automatic Mitigation Procedure (AMP)"	Change "MMIP 3" to "MMIP Appendix A"	Correct incorrect section reference
Appendix A, at defined term "Availability Measure"	Delete defined term	Term is defined, not used in the tariff/protocols
Appendix A, at defined term "Available Transfer Capacity"	Change "WSCC" to "WECC"	Update outdated reference to WSCC
Appendix A, at defined term "Black Start Generator"	Change "Contracts" to "Contracts."	Add needed period to end of sentence
Appendix A, at defined term "Conditional Energy Bids"	Delete defined term	Term is defined, not used in the tariff/protocols
Appendix A, at defined term "Congestion Management Charge"	Change "inter-zonal congestion" to "Inter-Zonal Congestion"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Congestion Management Charge"	Change "adjustment bids" to "Adjustment Bids"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Congestion Management Charge"	Change "congestion" to "Congestion"; change "congested" to "Congested"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Congestion Management Charge"	Change ".." to "."	Remove extra period at end of tariff-defined term

Section	Change	Reason for Change
Appendix A, at defined term "Cost Shifting"	Delete defined term	Term is defined, not used in the tariff/protocols
Appendix A, at defined term "Curtailable Demand"	Change "dispatch" to "Dispatch"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Curtailable Demand"	Change "real time" to "real-time"	Correct grammar
Appendix A, at defined term "Curtailable Demand"	Change "Non-spinning" to "Non-Spinning Reserve"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Delivery Upgrade"	Change "constraints" to "Constraints"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Demand Bid"	Delete defined term	The ISO and its markets are no longer operational
Appendix A, at defined term "Demand Market Participant"	Delete defined term	Term is defined, however, not used in the tariff/protocols
Appendix A, at defined term "Direct Access Generation"	Delete defined term	Term is defined, however, not used in the tariff/protocols
Appendix A, at defined term "Direct Assignment Facility"	Change "interconnection" to "Interconnection"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Dispatchable Loads"	Change "Dispatchable Loads" to "Dispatchable Load"	To consistently use the singular form in the defined term and the definition
Appendix A, at defined term "Electric Capacity"	Delete defined term	Term is defined, however, not used in the tariff/protocols
Appendix A, at defined term "Eligible Regulatory Must-Run Generation"	Delete defined term	Term is defined, however, not used in the tariff/protocols
Appendix A, at defined term "Emergency Startup"	Delete defined term	Term is defined, however, not used in the tariff/protocols
Appendix A, at defined term "Emissions Costs"	Change "generating unit" to "Generating Unit"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "EMS (Energy Management System)"	Change "real time" to "real-time"	Correct grammar
Appendix A, at defined term "Energy Efficiency Services"	Delete defined term	Term is defined, however, not used in the tariff/protocols
Appendix A, at defined term "Environmental Quality"	Delete defined term	Term is defined, however, not used in the tariff/protocols
Appendix A, at defined term "Equipment Clearances"	Delete defined term	Term is defined, however, not used in the tariff/protocols

Section	Change	Reason for Change
Appendix A, at defined term "Existing High Voltage Facility"	Change "section 4.2" to "Section 4.2"	Internal section references in the tariff/protocols are capitalized
Appendix A, at defined term "Ex Post GMM"	Change "real time" to "real-time"	Correct grammar
Appendix A, at defined term "Facility Thermal Ratings"	Delete defined term	Term is defined, however, not used in the tariff/protocols
Appendix A, at defined term "Flexible Generation"	Delete defined term	Term is defined, however, not used in the tariff/protocols
Appendix A, at defined term "Forbidden Operating Region"	Change "can not" to "cannot"	Correct incorrect word usage
Appendix A, at defined term "Forward Scheduling Charge"	Change "inter-SC trade" to "inter-Scheduling Coordinator trade"	To correct use of term that is not a tariff-defined term
Appendix A, at defined term "FTR (Firm Transmission Right)"	Change "congestion" to "Congestion"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "FTR (Firm Transmission Right)"	Change "schedule" to "Schedule"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Generation Dispatch Constraints"	Delete defined term	Term is defined, however, not used in the tariff/protocols
Appendix A, at defined term "Generation Scheduling"	Delete defined term	Term is defined, however, not used in the tariff/protocols
Appendix A, at defined term "Good Utility Practice"	Change "the." to "the"	Remove extraneous period
Appendix A, at defined term "Grid Operations Charge"	Change "redispatch costs" to "Redispatch costs"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "High Voltage Transmission Standby Serve"	Delete defined term	Term is defined, however, not used in the tariff/protocols, nor is the term "High Voltage Transmission Standby Service" used in the tariff/protocols
Appendix A, at defined term "Hour-Ahead Market"	Delete ", the PX"	The PX and its markets are no longer operational
Appendix A, at defined term "Hourly Ex Post Price"	Change "settlement period" to "Settlement Period"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Imbalance Energy"	Change "Non-spinning Reserves" to "Non-Spinning Reserves"	Not capitalized in section, but is a tariff-defined term

Section	Change	Reason for Change
Appendix A, at defined term "Instructed Imbalance Energy"	Change "real time" to "real-time"	Correct grammar
Appendix A, at defined term "Inter-Scheduling Energy Coordinator Trades"	Change "Inter-Scheduling Energy Coordinator Trades" to "Inter-Scheduling Coordinator Energy Trades"	Correct typographical error
Appendix A, at defined term "ISO Authorized Inspector"	Change "metering facilities" to "Metering Facilities (as that term is defined in the ISO Metering Protocol)"	Adapt language from deleted definition of term in ISO Metering Protocol to definition of same term in Appendix A
Appendix A, at defined term "ISO Control Area Balancing Function"	Change "real time" to "real-time"	Correct grammar
Appendix A, at defined term "ISO Control Area Balancing Function"	Change "reliability criteria" to "Reliability Criteria"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "ISO Memorandum Account"	Change "California Public Utility Commission" to "California Public Utilities Commission"	Reflect correct name of California Public Utilities Commission
Appendix A, at defined term "ISO Metered Entity"	Change "service area" to "Service Area"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "ISP (Internet Service Provider)"	Change "Wenet" to "WEnet"	Correct misspelling
Appendix A, at defined term "Local Furnishing Participating TO"	Change "Tax-Exempt Participating TO" to "Tax Exempt Participating TO"	Tariff-defined term is not hyphenated
Appendix A, at defined term "Local Reliability Criteria"	Change "Reliability criteria" to "Reliability Criteria"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Maintenance Outage"	Change "(ii) takes its Generating Unit" to "(ii) limits the capability of or takes its Generating Unit"	Make definition of term consistent with Appendix A definition of "Outage," which covers partial as well as full outages
Appendix A, at defined term "Marginal Generators"	Delete defined term	Term appears only in definition
Appendix A, at defined term "Marginal Loss Factor"	Delete defined term	Term appears only in definition
Appendix A, at defined term "Minimum Load Costs"	Change "generating unit" to "Generating Unit"	Not capitalized in section, but is a a tariff-defined term
Appendix A, at defined	Delete "described in	Referenced Section 3.3.1 has

Section	Change	Reason for Change
term "MSS Operator"	Section 3.3.1"	been deleted
Appendix A, at defined term "Municipal Tax Exempt TO"	Delete defined term	Term appears only in definition
Appendix A, at defined term "Net FTR Revenue"	Change "congested" to "Congested"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Net Negative Uninstructed Deviation"	Change "real time" to "real-time"	Correct grammar
Appendix A, at defined term "Net Negative Uninstructed Deviation"	Change "Imports" to "imports"	Not a tariff-defined term
Appendix A, at defined term "Net Negative Uninstructed Deviation"	Change "Exports" to "exports"	Not a tariff-defined term
Appendix A, at defined term "New High Voltage Facility"	Change "4.1" to "4.2"	Correct incorrect section reference
Appendix A, at defined term "Nomogram"	Change "WSCC" to "WECC"	Update outdated reference to WSCC
Appendix A, at defined term "Non-ISO Transmission Facilities"	Delete defined term	Term appears only in definition
Appendix A, at defined term "Non-PX Generation"	Delete defined term	Term appears only in definition, and refers to the PX
Appendix A, at defined term "Non-PX Load"	Delete defined term	Term appears only in definition, and refers to the PX
Appendix A, at defined term "Non-Spinning Reserve"	Change "ramping" to "Ramping"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Operating Reserve"	Change "WSCC" to "WECC"	Update outdated reference to WSCC
Appendix A, at defined term "OPF (Optimal Power Flow)"	Change "constraints" to "Constraints"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Outage"	Change "capacity planned" to "capacity, planned"	Correct grammar
Appendix A, at defined term "PMS (Power Management System)"	Change "real time" to "real-time"	Correct grammar
Appendix A, at defined term "PX (Power Exchange)"	Delete defined term	PX no longer is operational
Appendix A, at defined term "PX Auction	Delete defined term	PX no longer is operational

Section	Change	Reason for Change
Activity Rules"		
Appendix A, at defined term "Qualifying Hours"	Delete defined term	Appears only in definition
Appendix A, at defined term "Real-Time Dispatch ('RTD') Software"	Change "('RTD')" to "(RTD)"	Quotation marks around shortened form of term are unnecessary
Appendix A, at defined term "Real Time Market"	Change "real time" to "real-time"	Correct grammar
Appendix A, at defined term "Regulation"	Change "WSCC" to "WECC"	Update outdated reference to WSCC
Appendix A, at defined term "Regulation"	Change "real time" to "real-time"	Correct grammar
Appendix A, at defined term "Reliability Must-Run Charge"	Change "Reliability Must-Run Charge" to "Reliability Must-Run Charge (RMR Charge)"	Provide short form for tariff-defined term
Appendix A, at defined term "Reliability Must-Run Charge"	Change "The sum payable each month by a Responsible Utility to the ISO for the costs of Reliability Must-Run Generation" to "The sum payable by a Responsible Utility to the ISO pursuant to Section 5.2.7 of the ISO Tariff for the costs, net of all applicable credits, incurred under the RMR Contract"	Adapt language from deleted definition of term "RMR Charge" in Annex 1 to the Settlement and Billing Protocol to definition of similar term in Appendix A
Appendix A, at defined term "Reliability Must-Run Contract (RMR Contract)"	Change "A rate schedule on file at FERC and in effect, or a contract between the ISO and a Generator, giving the ISO the right to call on the Generator to generate Energy or provide Ancillary Services from the Generating Unit as and when required to ensure the reliability of the ISO Controlled Grid, in return for certain payments" to "A Must-Run Service Agremeent between the owner of an RMR Unit and the ISO"	Adapt language from deleted definition of term "RMR Contract" in Annex 1 to the Settlement and Billing Protocol to definition of same term in Appendix A
Appendix A, at defined	Change "Reliability Must-	Provide short form for tariff-

Section	Change	Reason for Change
term "Reliability Must-Run Generation"	Run Generation" to "Reliability Must-Run Generation (RMR Generation)"	defined term
Appendix A, at defined term "Reliability Must-Run Generation"	Change "WSCC" to "WECC"	Update outdated reference to WSCC
Appendix A, at defined term "Reliability Must-Run Unit"	Change "Reliability Must-Run Unit" to "Reliability Must-Run Unit (RMR Unit)"	Provide short form for tariff-defined term
Appendix A, at defined term "Reliability Must-Run Unit"	Change "Contract" to "Contract."	Add needed punctuation at end of sentence
Appendix A, at defined term "Reliability Upgrade"	Change "WSCC" to "WECC"	Update outdated reference to WSCC
Appendix A, at defined term "REMnet"	Change "meter data" to "Meter Data"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Replacement Reserve"	Change "ramping" to "Ramping"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Replacement Reserve"	Change "Load point" to "operating level"	To correct incorrect use of term
Appendix A, at defined term "RTG (Regional Transmission Group)"	Delete defined term	Term appears only in definition
Appendix A, at defined term "Schedule"	Change "self provided" to "self-provided"	Correct grammar
Appendix A, at defined term "Scheduling Coordinator Metered Entity or SC Metered Entity"	Change "means a" to "A"	Conform format of definition to that used for the other definitions in Appendix A
Appendix A, at defined term "Security Monitoring"	Change "real time" to "real-time"	Correct grammar
Appendix A, at defined term "Standard Ramp (ing)"	Change "Ramp (ing)" to "Ramp (-ing")"	Correct grammar
Appendix A, at defined term "Start-Up Fuel Costs"	Change "generating unit" to "Generating Unit"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Suggested Adjusted Schedule"	Change "schedules" to "Schedules"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Supply Market	Delete defined term	Term appears only in definition

Section	Change	Reason for Change
Participant"		
Appendix A, at defined term "System Emergency"	Change "outages" to "Outages"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Tax Exempt Participating TO"	Change "Tax-Exempt Debt" to "Tax Exempt Debt"	Tariff-defined term is not hyphenated
Appendix A, at defined term "Transfer Schedule"	Delete defined term	Term appears only in definition
Appendix A, at defined term "Uninstructed Imbalance Energy"	Change "real time" to "real-time"	Correct grammar
Appendix A, at defined term "Usage Charge"	Change "congested" to "Congested"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Voltage Support"	Change "system emergency" to "System Emergency"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Wheeling Out"	Change "distribution system" to "Distribution System"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "Wheeling Through"	Change "distribution system" to "Distribution System"	Not capitalized in section, but is a tariff-defined term
Appendix A, at defined term "WSCC (Western Systems Coordinating Council)"	Change "its successor" to "its successor, the WECC"	Modify outdated reference to WSCC
New defined term in Appendix A for "WECC (Western Electricity Coordinating Council)"	Add defined term "WECC (Western Electricity Coordinating Council)," and define the term as "The Western Electricity Coordinating Council or its successor"	Provide tariff-defined term that reflects the correct current name of the WECC
Appendix C, at title	Change "Day-ahead Schedule" to "Day-Ahead Schedule"	Not capitalized in section, but is a tariff-defined term
Appendix C, at column titled "Non-PX SCs"	Change "Non-PX SCs" to "SCs"	The PX and its markets are no longer operational, and thus a distinction need not be made between the PX and non-PX Scheduling Coordinators
Appendix C, at column titled "PX"	Delete column	The PX and its markets are no longer operational, and thus the provisions in this column are inapplicable
Appendix C, at column titled "PX Participants"	Delete column	The PX and its markets are no longer operational, and thus the

Section	Change	Reason for Change
		provisions in this column are inapplicable
Appendix C, at line 0	Change "loop flows" to "Loop Flows"	Not capitalized in line, but is a tariff-defined term
Appendix C, at line 0	Change "outages" to "Outages"	Not capitalized in line, but is a tariff-defined term
Appendix C, at line 3	Change "Reliability Must Run Units" to "Reliability Must-Run Units"	Tariff-defined term is hyphenated
Appendix C, at lines 6-9, 35-37	Delete text in lines and designate the lines as "not used"	The PX and its markets are no longer operational, and thus the provisions in these lines are inapplicable
Appendix C, at lines 14, 27	Change "inter-zonal congestion management" to "Inter-Zonal Congestion Management" (2 places)	Not capitalized in lines, but is a tariff-defined term
Appendix C, at lines 15-16, 18-20, 33	Change "inter-zonal congestion" to "Inter-Zonal Congestion"	Not capitalized in lines, but is a tariff-defined term
Appendix C, at lines 21-22	Delete "(the PX may iterate with PX participants)" (2 places)	The PX and its markets are no longer operational, and thus the provisions in these lines are inapplicable
Appendix C, at line 23	Change "preferred schedules" to "Preferred Schedules"	Not capitalized in line, but is a tariff-defined term
Appendix C, at lines 29, 30	Change "final schedules" to "Final Schedules" (2 places)	Not capitalized in lines, but is a tariff-defined term
Appendix C, at line 34	Change "zonal" to "Zonal"	Not capitalized in line, but is a tariff-defined term
Appendix C, at line 34	Change "SCs" to "SC's"	Correct grammar
Appendix D, at (e)	Change "Black Start unit" to "Black Start Unit"	Conform with term defined in Appendix D
Appendix E, at 6	Change "Day Ahead or Hour Ahead" to "Day-Ahead or Hour-Ahead"	Tariff-defined term incorrectly not hyphenated in section
Appendix F, at Sched. 1, Part A(3) & (6)	Change "settlement interval" to "Settlement Interval"	Not capitalized in section, but is a tariff-defined term
Appendix F, at Sched. 1, Part C	Change "WECC security coordinator" to "WECC reliability coordinator"	WECC has changed terms
Appendix F, at Sched. 1, Part C	Change "Managment" to "Management"	Correct incorrect spelling
Appendix 1, at Sched. 1, Part C	Change "ISO Board" to "ISO Governing Board"	Tariff-defined term is ISO Governing Board
Appendix F, at Sched.	Change "ISOs" to "ISO's"	Correct incorrect spelling

Section	Change	Reason for Change
1, Part D		
Appendix F, at Sched. 1, Part D	Change "business day" to "Business Day"	Not capitalized in section, but is a tariff-defined term
Appendix F, at Sched. 1, Part D	Change "Periodic Financial reports" to "Periodic Financial Reports"	Capitalize word in heading to be consistent with other headings
Appendix F, at Sched. 1, Part D	Change "Board" to "ISO Governing Board"; change "ISO Board" to "ISO Governing Board"; change "ISO Board of Governors" to "ISO Governing Board"	Tariff-defined term is ISO Governing Board
Appendix F, at Sched. 1, Part E, Table 1	Change "Board of Governors" to "ISO Governing Board"	Tariff-defined term is ISO Governing Board
Appendix F, at Sched. 2, "Black Start Capability" section	Change "Black Start Capability" to "Black Start capability"	Not a tariff-defined term
Appendix F, at Sched. 3, Sec. 4.5	Change "Particpating" to "Participating"	Correct misspelling
Appendix F, at Sched. 3, Sec. 4.5	Change "New Participating" to "New Participating"	Delete extra space between words
Appendix F, at Sched. 3, Sec. 5.1	Change ".." to "."	Delete extra period
Appendix F, at Sched. 3, Sec. 6.1	Change "under- recovery" to "under-recovery" (2 places)	Delete extra space between hyphenated words
Appendix F, at Sched. 3, Sec. 8.3	Change "from the ISO Operational Control" to "from the ISO Operational Control in accordance with Section 3.4 of the Transmission Control Agreement"	Clarify the reference in the section
Appendix F, at Sched. 3, Sec. 9.1	Change "approriate" to "appropriate"	Correct incorrect spelling
Appendix H	Change "Section 7.14" to "Section 7.1.4 of the ISO Tariff"	Correct and clarify section reference
Index to ISO Protocols	Add titles and page numbers for Eligible Intermittent Resources Protocol, Enforcement Protocol, and UDP Aggregation Protocol	Update outdated index to reflect current titles and page numbers

Section	Change	Reason for Change
ASRP Table of Contents	Change "Long Term" to "Long-Term"	Correct grammar
ASRP Table of Contents	Change "Self Provide" to "Self-Provide"; change "Self Provision" to "Self-Provision" (2 places)	Correct grammar
ASRP 1.2.2	Delete definition of "ISO Home Page"	Definition is duplicative of term defined in the Master Definitions Supplement
ASRP 2.1.1	Change "dispatch" to "Dispatch"	Not capitalized in section, but is a tariff-defined term
ASRP 2.1.1(a)	Change "Western System Coordinating Council (WSCC)" to "Western Electricty Coordinating Council (WECC)"	Update outdated reference to WSCC
ASRP 2.1.1(b)	Change "dispatch" to "Dispatch"	Not capitalized in section, but is a tariff-defined term
ASRP 2.2.1	Change "WSCC" to "WECC"	Update outdated reference to WSCC
ASRP 2.2.2	Change "WSCC" to "WECC"	Update outdated reference to WSCC
ASRP 3.2	Change "Self Provide" to "Self-Provide"	Correct grammar
ASRP 3.2	Change "self provide" to "self-provide"	Correct grammar
ASRP 4.1.1	Change "WSCC" to "WECC"	Update outdated reference to WSCC
ASRP 4.1.3	Change "WSCC" to "WECC"	Update outdated reference to WSCC
ASRP 4.1.6	Change "WSCC" to "WECC"	Update outdated reference to WSCC
ASRP 4.5.2	Change "self provide" to "self-provide"	Correct grammar
ASRP 5	Change "WSCC" to "WECC"	Update outdated reference to WSCC
ASRP 5.2	Change "self provided" to "self-provided" (2 places)	Correct grammar
ASRP 5.2(a)	Change "theScheduling" to "the Scheduling"	Correct misspelling
ASRP 5.8.5	Change "Self Provision" to "Self-Provision"	Correct grammar
ASRP 5.8.5	Change "self provide" to "self-provide"	Correct grammar
ASRP 6.3	Change "zone" to "Zone"	Not capitalized in section, but is a tariff-defined term
ASRP 6.5.3	Change "self provide" to "self-provide"	Correct grammar
ASRP 6.5.3	Change "Self Provision" to	Correct grammar

Section	Change	Reason for Change
	"Self-Provision"	
ASRP 7.1	Change "WSCC" to "WECC"	Update outdated reference to WSCC
ASRP 7.5.1	Change "Long Term" to "Long-Term"; change "long term" to "long-term"	Correct grammar
ASRP 10.2	Change "settlement Period" to "Settlement Period"	Not capitalized in section, but is a tariff-defined term
ASRP 10.3	Change "Dispatch instruciton" to "Dispatch instruction"	Correct misspelling
ASRP 11.4	Change "self provision" to "self-provision"	Correct grammar
DFP 1.1	Change "system reliability" to "System Reliability"	Not capitalized in section, but is a tariff-defined term
DFP 1.2.2	Delete the definition of "ISO Home Page"	Definition is duplicative of term defined in the Master Definitions Supplement
DFP 3.1	Change "load" to "Load"	Not capitalized in section, but is a tariff-defined term
DP Table of Contents	Change "WSCC" to "WECC"	Update outdated reference to WSCC
DP Table of Contents	Change "REAL TIME" to "REAL-TIME" (3 places)	Correct grammar
DP Table of Contents	Change "Security Coordinator" to "Reliability Coordinator" and change "WSCC Security Coordinators" to "WECC Reliability Coordinators"	Name of WSCC and term Reliability Coordinators have changed
DP Table of Contents	Change "Real Time" to "Real-Time" (5 places)	Correct grammar
DP 1.1(a)	Change "real time" to "real-time"	Correct grammar
DP 1.1(b)	Change "real time" to "real-time"	Correct grammar
DP 1.1(e)	Change "WSCC" to "WECC"	Update outdated reference to WSCC
DP 1.2.2	Delete definition of "ISO Home Page"	Definition is duplicative of term defined in the Master Definitions Supplement
DP 1.2.2	Change "Security Coordinator to "Reliability Coordinator" and "WSCC" to "WECC"	Update outdated references to Security Coordinator and WSCC
DP 1.2.2	Change "real time" to "real-time" (2 places)	Correct grammar

Section	Change	Reason for Change
DP 2.1	Change "WSCC" to "WECC"	Update outdated reference to WSCC
DP 2.1.1	Change "WSCC" to "WECC" (8 places)	Update outdated reference to WSCC
DP 2.2	Change "WSCC" to "WECC"	Update outdated reference to WSCC
DP 2.3	Change "WSCC" to "WECC"	Update outdated reference to WSCC
DP 3	Change "REAL TIME" to "REAL-TIME"	Correct grammar
DP 3.1	Change "real time" to "real-time"	Correct grammar
DP 3.2	Change "real time" to "real-time"	Correct grammar
DP 3.3	Change "WSCC" to "WECC"	Update outdated reference to WSCC
DP 3.3	Change "real time" to "real-time"	Correct grammar
DP 3.8.1	Change "WSCC" to "WECC" and change "Security Coordinator" to "Reliability Coordinator" (2 places)	Update outdated references to WSCC and Security Coordinator
DP 3.8.1	Change "Security Coordinator" to "Reliability Coordinator"	WECC has changed terms
DP 3.8.2	Change "WSCC" to "WECC" (2 places)	Update outdated reference to WSCC
DP 6.1	Change "nomograms" to "Nomograms"	Not capitalized in section, but is a tariff-defined term
DP 6.8	Change "real time" to "real-time"	Correct grammar
DP 6.9	Change "WSCC" to "WECC" (2 places)	Update outdated reference to WSCC
DP 6.9	Change "Security Coordinator" to "Reliability Coordinator" (2 places); change "Security Coordinators" to "Reliability Coordinators"	WECC has changed terms
DP 6.9.1	Change "nomogram" to "Nomogram"	Not capitalized in section, but is a tariff-defined term
DP 6.9.1	Change "Security Coordinator" to "Reliability Coordinator" (2 places)	Update outdated reference to Security Coordinator
DP 6.9.2	Change "WSCC Security Coordinators" to "WECC Reliability Coordinators"	Update outdated reference to WSCC and Security Coordinators
DP 6.9.2	Change "Security	WECC has changed terms

Section	Change	Reason for Change
	Coordinator" to "Reliability Coordinator" (4 places); change "Security Coordinators" to "Reliability Coordinators" (2 places)	
DP 6.9.2(a)	Change "WSCC" to "WECC"	Update outdated reference to WSCC
DP 6.9.2(a)	Change "control area" to "Control Area"	Not capitalized in section, but is a tariff-defined term
DP 6.9.2(a)	Change "security monitoring" to "Security Monitoring"	Not capitalized in section, but is a tariff-defined term
DP 6.9.2(b)	Change "system reliability" to "System Reliability" (2 places)	Not capitalized in section, but is a tariff-defined term
DP 7	Change "REAL TIME" to "REAL-TIME"	Correct grammar
DP 8	Change "REAL TIME" to "REAL-TIME"	Correct grammar
DP 8.1.1	Change "Real Time" to "Real-Time"	Correct grammar
DP 8.1.1	Change "Real Time" to "real-time"	Correct grammar
DP 8.1.1	Change "real time" to "real-time"	Correct grammar
DP 8.2	Change "real-time" to "real time"	Correct gramma
DP 8.3.1	Change "RTD software" to "RTD Software"	Not capitalized in section, but is a tariff-defined term
DP 8.4	Change "constraints" to "Constraints"	Not capitalized in section, but is a tariff-defined term
DP 8.6	Change "Real Time" to "Real-Time"	Correct grammar
DP 8.6.1	Change "Real Time" to "Real-Time"	Correct grammar
DP 8.6.2(d)	Change "real time" to "real-time"	Correct grammar
DP 8.6.3	Change "Real Time" to "Real-Time"	Correct grammar
DP 8.6.3	Change "WSCC" to "WECC" (2 places)	Update outdated reference to WSCC
DP 8.6.3	Change "real time" to "real-time"	Correct grammar
DP 8.6.3(i)	Change "RTD software" to "RTD Software"	Not capitalized in section, but is a tariff-defined term
DP 8.7.3(d)	Change "Energy bid" to "Energy Bid"	Not capitalized in section, but is a tariff-defined term
DP 8.7.4(d)	Change "Energy bid" to	Not capitalized in section, but is a

Section	Change	Reason for Change
	"Energy Bid"	tariff-defined term
DP 8.7.6(b)	Change "Black Start Agreement" to "Black Start agreement"	"Black-Start Agreement" is not a tariff-defined term or the name of a specific agreement
DP 8.8	Change "Real Time" to "Real-Time"	Correct grammar
DP 10.1.1	Change "alert notice" to "Alert Notice"	Not capitalized in section, but is a tariff-defined term
DP 10.1.3	Change "Security Coordinators" to "Reliability Coordinators"	Updated outdated reference to Security Coordinators
DP 10.1.3	Change "WSCC" to "WECC" (2 places)	Update outdated references to WSCC
DP 10.2.2(c)	Change "WSCC" to "WECC"	Update outdated references to WSCC
DP 10.3	Change "real time" to "real-time" (2 places)	Correct grammar
DP 10.4.2	Change "self provision" to "self-provision"	Correct grammar
MMIP Table of Contents	Change "and PX" to "and Other"	Update outdated reference to PX
MMIP Table of Contents	Delete Table of Contents reference to MMIP 4.7	Reflect deletion of original MMIP 4.7 to remove outdated provisions concerning PX
MMIP Table of Contents	Change "MMIP 4.8" to "MMIP 4.7"	Modify section numbering in light of deletion of original MMIP 4.7
MMIP 1.2.2	Delete definition of "ISO Home Page"	Definition is duplicative of term defined in the Master Definitions Supplement
MMIP 1.2.2	Delete "or PX" and "and PX"	Remove outdated reference to PX
MMIP 1.3.1.2	Delete section	Remove outdated reference to PX
MMIP 1.3.1.3	Change "1.3.1.3" to "1.3.1.2"	Correct section number in light of deletion of original MMIP 1.3.1.2
MMIP 2.1.3	Change "loop flow" to "Loop Flow"	Not capitalized in section, but is a tariff-defined term
MMIP 2.1.3	Change "constraints" to "Constraints"	Not capitalized in section, but is a tariff-defined term
MMIP 2.1.3	Change "PX or ISO Tariffs" to "ISO Tariff"	Update outdated reference to PX
MMIP 2.1.4	Change "PX" to "Other"	Remove outdated reference to PX
MMIP 2.1.4	Delete "including the PX"	Remove outdated reference to PX
MMIP 2.2.2	Change "In consultation with the Compliance Unit of the PX, the" to "The"	Remove outdated reference to PX
MMIP 2.2.3	Delete "; and the Market Surveillance Unit shall consult with the Compliance Unit of the	The PX and its markets are no longer operational

Section	Change	Reason for Change
	PX with respect to such effects on both the PX and ISO Markets"	
MMIP 2.3.1	Delete "administered by the PX or" (2 places); delete "to the PX or"	Remove outdated references to PX
MMIP 2.3.2	Change "it's recommendations" to "its recommendations"	Correct grammar
MMIP 2.3.2	Delete "or for referral to the PX as to rules and protocols under the PX's control,"; delete "or by referral to the PX, of the markets administered by the PX,"	Remove outdated references to PX
MMIP 2.3.3	Delete ", in cooperation with the PX Compliance Unit where appropriate,"; change "ISO or PX Tariffs" to "ISO Tariff"	Remove outdated references to PX
MMIP 2.3.4	Delete "and, in consultation with the Compliance Unit of the PX, all possible measures that may be taken by the PX,"; delete "the PX or"	Remove outdated references to PX
MMIP 3.3.5	Change "Any Market" to "Any Market"	Remove extra space between words
MMIP 4.3	Change ", whether developed by the ISO or the PX" to "developed by the ISO"	Remove outdated references to PX
MMIP 4.5.1	Delete ", the PX"	Remove outdated reference to PX
MMIP 4.5.1	Change "ISO market" to "ISO Market"	Not capitalized in section, but is a tariff-defined term
MMIP 4.7	Delete section	Remove outdated provisions concerning PX
MMIP 4.8	Change "MMIP 4.8" to "MMIP 4.7"	Update section numbering in light of removal of original MMIP 4.7
MMIP 5.2.1.2	Change "generation" to "Generation"	Not capitalized in section, but is a tariff-defined term
MMIP 5.2.2.1	Change "affiliate" to "Affiliate"	Not capitalized in section, but is a tariff-defined term
MMIP 5.2.2.2	Change "affiliate" to "Affiliate"	Not capitalized in section, but is a tariff-defined term
MMIP 6.2	Delete last sentence of section	Remove outdated provisions concerning PX
MMIP App. A, 1.2	Change "the Commission"	The tariff-defined term is FERC

Section	Change	Reason for Change
	to "FERC"	
MMIP App. A, 2.1	Change "Day-ahead" to "Day-Ahead"	Not capitalized in section, but is a tariff-defined term
MMIP App. A, 2.1	Change "Hour-ahead" to "Hour-Ahead"	Not capitalized in section, but is a tariff-defined term
MMIP App. A, 2.1	Change "market clearing prices" to "Market Clearing Prices"	Not capitalized in section, but is a tariff-defined term
MMIP App. A, 2.1	Change "Real-time" to "real-time"	Correct grammar
MMIP App. A, 2.1	Change "Real Time Imbalance Energy Market" to "real-time Imbalance Energy market" (2 places)	Correct capitalization of term
MMIP App. A, 2.2	Change "section 2.4" to "Section 2.4"	Internal section references in the tariff/protocols are capitalized
MMIP App. A, 2.4.1(1)	Change "real-time" to "real time"	Correct grammar
MMIP App. A, 2.4.1(2)	Change "market clearing price" to "Market Clearing Price"	Not capitalized in section, but is a tariff-defined term
MMIP App. A, 3.1	Change "section 3.1.1" to "Section 3.1.1"	Internal section references in the tariff/protocols are capitalized
MMIP App. A, 3.1.1.1	Change "zone" to "Zone"	Not capitalized in section, but is a tariff-defined term
MMIP App. A, 3.2.1	Change "zone" to "Zone"	Not capitalized in section, but is a tariff-defined term
MMIP App. A, 3.2.1	Change "market-clearing prices" to "Market Clearing Prices"	Not capitalized in section, but is a tariff-defined term, and tariff-defined term is not hyphenated
MMIP App. A, 3.2.2.1	Change "and analytical" to "and analytical"	Remove extra space between words
MMIP App. A, 3.2.2.2	Change "section 3.2.2.2" to "Section 3.2.2.2"	Internal section references in the tariff/protocols are capitalized
MMIP App. A, 3.2.2.2	Change "zone" to "Zone"	Not capitalized in section, but is a tariff-defined term
MMIP App. A, 3.2.3	Change "the Commission" to "FERC"	The tariff-defined term is FERC
MMIP App. A, 3.2.3	Change "section 3.1.1" to "Section 3.1.1"	Internal section references in the tariff/protocols are capitalized
MMIP App. A, 3.3	Change "ISO market" to "ISO Market"	Not capitalized in section, but is a tariff-defined term
MMIP App. A, 3.3	Change "Section 3.1.2" to "Section 3.1.1 above"	To correct and clarify section reference
MMIP App. A, 4.2.2(a)	Change "Section 3.1.1" to "Section 3.1.1 above"	To clarify section reference
MMIP App. A, 4.2.2(b)	Change "Real-time" to	Correct grammar

Section	Change	Reason for Change
	"real-time"	
MMIP App. A, 4.2.2(b)	Change "Real Time Imbalance Energy Market" to "real-time Imbalance Energy market" (2 places)	Correct capitalization of terms
MMIP App. A, 4.2.2(b)	Change "process prior" to "process prior"	Remove extra space between words
MMIP App. A, 4.2.2(d)	Change "the Commission" to "FERC"	The tariff-defined term is FERC
MMIP App. A, 4.2.2(e)	Change "zonal" to "Zonal"	Not capitalized in section, but is a tariff-defined term
MMIP App. A, 4.2.2(e)	Change "Energy bids" to "Energy Bids"	Not capitalized in section, but is a tariff-defined term
MMIP App. A, 4.2.2(e)	Change "zone" to "Zone"	Not capitalized in section, but is a tariff-defined term
MMIP App. A, 4.2.2(e)	Change "zones" to "Zones"	Not capitalized in section, but is a tariff-defined term
MMIP App. A, 4.3	Change "dispatch instructions" to "Dispatch Instructions"	Not capitalized in section, but is a tariff-defined term
MMIP App. A, 4.3	Change "forthin" to "forth in"	Insert needed space between words
OCP 1.1.2	Change "The Outage Coordination Office is located in Folsom and Alhambra" to "The Outage Coordination Office is located in Folsom"	The Outage Coordination Office located in Alhambra closed in 2003
OCP 1.2.2	Delete definition of "ISO Home Page"	Definition is duplicative of term defined in the Master Definitions Supplement
OCP 2.2.1(d)	Change "outage" to "Outage"	Not capitalized in section, but is a tariff-defined term
SBP Table of Contents	Change "Special Definitions for this Protocol" to "[Not used]"	No special definitions contained in protocol, in light of deletion of defined terms from SBP 1.2.2 as described below in this table
SBP 1.2.2	Delete section text and replace with "[Not used]"	All of the definitions in the section are duplicative of terms defined in the Master Definitions Supplement
SBP 2.1.1(g)	Change "transmission losses" to "Transmission Losses"	Not capitalized in section, but is a tariff-defined term
SBP 2.1.1(h)	Change "Hour-Ahead market" to "Hour-Ahead Market"	Not capitalized in section, but is a tariff-defined term
SBP 2.1.3(n)	Change "WSCC" to	Update outdated reference to

Section	Change	Reason for Change
	"WECC"	WSCC
SBP 2.1.3(q)	Change "transmission losses" to "Transmission Losses"	Not capitalized in section, but is a tariff-defined term
SBP 2.1.6(g), -(i)(1), -(i)(3)	Change "Inter-SC Trade" to "inter-Scheduling Coordinator trade"	To correct use of term that is not a tariff-defined term
SBP 2.1.6(h)	Change "Existing Transmission Contracts" to "Existing Contracts"	The tariff-defined term is Existing Contracts
SBP 2.1.6(i)(1)	Change "generation" to "Generation"	Not capitalized in section, but is a tariff-defined term
SBP 2.1.6(i)(4)	Change "wheeling" to "Wheeling"	Not capitalized in section, but is a tariff-defined term
SBP 2.2.2	Change "Demand forecast" to "Demand Forecast"	Not capitalized in section, but is a tariff-defined term
SBP 2.2.2	Change "thenotification" to "the notification"	Correct typographical error
SBP 3.3.1(l)	Change "real time" to "real-time"	Correct grammar
SBP 3.3.1(m)	Change "real time" to "real-time"	Correct grammar
SBP 5.1.1.2(h)	Change "WSCC" to "WECC"	Update outdated reference to WSCC
SBP 5.1.1.2(j)	Change "Existing contracts" to "Existing Contracts"	Not capitalized in section, but is a tariff-defined term
SBP 5.1.2.2(h)	Change "WSCC" to "WECC"	Update outdated reference to WSCC
SBP 5.1.3.3(h)	Change "WSCC" to "WECC"	Update outdated reference to WSCC
SBP 5.1.4.3(h)	Change "WSCC" to "WECC"	Update outdated reference to WSCC
SBP 5.3	Change "Hour-Ahead market" to "Hour-Ahead Market"	Not capitalized in section, but is a tariff-defined term
SBP 5.3	Change "System Resoruce" to "System Resource"	Correct typographical error; not capitalized in section, but is a tariff-defined term
SBP 6.1.1(g)	Change "minimum load cost" to "Minimum Load Cost"	Not capitalized in section, but is a tariff-defined term
SBP 6.1.3(f)	Change "WSCC" to "WECC"	Update outdated reference to WSCC
SBP 6.1.3(j)	Change "redispatch" to "Redispatch"	Not capitalized in section, but is a tariff-defined term; tariff-defined term is not hyphenated
SBP 6.7	Change "dispatch	Not capitalized in section, but is a

Section	Change	Reason for Change
	instruction" to "Dispatch Instruction"	tariff-defined term
SBP 6.8	Change "minimum load cost" to "Minimum Load Cost" (6 places)	Not capitalized in section, but is a tariff-defined term
SBP Appendix	Change "zones" to "Zones"	Not capitalized in section, but is a tariff-defined term
SCAP 1.2.2	Delete definitions of "ISO Home Page" and "SC Metered Entity"	Definitions are duplicative of terms defined in the Master Definitions Supplement
SCAP 1.2.2	Delete definition of "SC Applicant"	Definition is substantially the same as the definition of the same term defined in the Master Definitions Supplement
SCAP 1.2.2	Delete definition of "ISO Metered Entity"	Definition is outdated version of term defined in Master Definitions Supplement
SCAP 1.2.2	Change "industry approved" to "industry-approved"	Correct grammar
SCAP 1.2.2	Change "meter data" to "Meter Data" (2 places)	Not capitalized in section, but is a tariff-defined term
SCAP 1.2.2	Change "(VAN) means" to "(VAN) means"	Remove extra space between words
SCAP 1.2.2	Change "ensure that" to "ensure that"	Remove extra space between words
SCAP 2.2(c)	Change "meter service agreements" to "Meter Service Agreements"	Capitalized term is name of specific agreements
SCAP 2.2(c)	Change "interim black start agreement" to "Interim Black Start Agreement"	Capitalized term is name of a specific agreement
SCAP 2.2(d)	Change "Grid Management charge" to "Grid Management Charge"	Not capitalized in section, but is a tariff-defined term
SCAP 2.2(d)	Change "Grid Operations charge" to "Grid Operations Charge"	Not capitalized in section, but is a tariff-defined term
SCAP 2.2(d)	Change "Usage charges" to "Usage Charges"	Not capitalized in section, but is a tariff-defined term
SCAP 2.5	Change "business days" to "Business Days"	Not capitalized in section, but is a tariff-defined term
SCAP 2.6.2	Change "An SC" to "An SC"	Remove extra space between words
SCAP 2.6.2(a)	Change "participating generator agreements" to "Participating Generator	Captialized term is name of specific agreements

Section	Change	Reason for Change
	Agreements"	
SCAP 2.6.2(c)	Change "meter service agreements" to "Meter Service Agreements"	Capitalized term is name of specific agreements
SCAP 2.6.2(e)	Change "California Public Utility Commission" to "California Public Utilities Commission"	Reflect correct name of California Public Utilities Commission
SCAP 4.1	Change "meter service agreements" to "Meter Service Agreements"	Capitalized term is name of specific agreements
SCAP 4.1	Change "interim black start agreements" to "Interim Black Start Agreements"	Capitalized term is name of specific agreements
SCAP 6(b)	Change "meter service agreements" to "Meter Service Agreements"	Capitalized term is name of specific agreements
SCAP 6(b)	Change "interim black start agreements" to "Interim Black Start Agreements"	Capitalized term is name of specific agreements
SCAP 7.1.2	Change "business days" to "Business Days"	Not capitalized in section, but is a tariff-defined term
SCAP App. A, 2.2	Change "business days" to "Business Days"	Not capitalized in section, but is a tariff-defined term
SCAP App. A, 5.1	Change "meter service agreements" to "Meter Service Agreements" (2 places)	Capitalized term is name of specific agreements
SCAP App. A, 5.1(a)	Change "participating generator agreements" to "Participating Generator Agreements"	Not capitalized in section, but is a tariff-defined term
SCAP App. A, 6.2	Change "business days" to "Business Days" (2 places)	Not capitalized in section, but is a tariff-defined term
SCAP App. A, 6.4	Change "meter service agreements" to "Meter Service Agreements"	Capitalized term is name of specific agreements
SCAP App. A, 6.4	Change "interim black start agreements" to "Interim Black Start Agreements"	Capitalized term is name of specific agreements
SCAP App. B	Change "business days" to "Business Days" (2 places)	Not capitalized in section, but is a tariff-defined term
SP Table of Contents	Change "Special definitions for this	No special definitions contained in protocol, in light of deletion of

Section	Change	Reason for Change
	Protocol" to "[Not used]"	defined terms from SBP 1.2.2 as described below in this table
SP Table of Contents	Change "Real Time" to "Real-Time"	Correct grammar
SP Table of Contents	Change "REAL TIME" to "REAL-TIME"	Correct grammar
SP 1.1(a)	Change "real time" to "real-time"	Correct grammar
SP 1.2.2	Delete section text and replace with "[Not used]"	All of the definitions in the section are duplicative of terms defined in the Master Definitions Supplement
SP 1.2.3	Change "willprevail" to "will prevail"	Add space between words
SP 3(e)	Change "real time" to "real-time"	Correct grammar
SP 3.1.1	Change "Demand forecast" to "Demand Forecast"	Not capitalized in section, but is a tariff-defined term
SP 3.1.4	Change "non-participating transmission owners" to "Non-Participating TOs"	Not capitalized in section, but is a tariff-defined term
SP 3.2.1.1	Change "By Two Hours Before Close of the PX Day-Ahead Market" to "By 5:00 am"; change "By two hours before the close of the PX Day-Ahead Market on the day ahead of" to "By no later than 5:00 am on the day before"	The PX and its markets are no longer operational; these changes are needed to accurately reflect the operation of the markets subsequent to the PX's stopping operations, and to implement changes to language in section to conform with similar changes in Section 2.2.12.2, *et seq.*, as approved in the proceeding concerning Amendment No. 56 to the ISO Tariff
SP 3.2.1.2	Change "By One Hour Before Close of the PX Day-Ahead Market" to "By 6:00 am"; change "By one hour before the close of the PX Day-Ahead Market on the day prior to" to "By no later than 6:00 am on the day before"	The PX and its markets are no longer operational; these changes are needed to accurately reflect the operation of the markets subsequent to the PX's stopping operations, and to implement changes to language in section to conform with similar changes in Section 2.2.12.2, *et seq.*, as approved in the proceeding concerning Amendment No. 56 to the ISO Tariff
SP 3.2.3	Change "Demand forecasts" to "Demand Forecasts"	Not capitalized in section, but is a tariff-defined term

Section	Change	Reason for Change
SP 3.2.6.1(h)	Change "Preferred Day Ahead Schedules" to "Preferred Day-Ahead Schedules"	Defined term should be hyphenated
SP 3.2.6.3	Change "Existing Transmission Contract" to "Existing Contract"	The tariff-defined term is Existing Contracts
SP 3.2.6.3	Change "ETC" to "Existing Contract"	Correct use of tariff-defined term
SP 3.2.6.3	Change "New Firm Use" to "new firm use"	Not a tariff-defined term
SP 3.2.8.3	Change "Existing Transmission Contract" to "Existing Contract"	The tariff-defined term is Existing Contracts
SP 3.2.8.3	Change "ETC" to "Existing Contract"	Correct use of tariff-defined term
SP 3.2.8.3	Change "New Firm Use" to "new firm use"	Not a tariff-defined term
SP 3.2.10	Change ",an" to ", an"	Add space between comma and word
SP 3.2.11	Change "zone" to "Zone"	Not capitalized in section, but is a tariff-defined term
SP 3.2.11	Change "zonal" to "Zonal"	Not capitalized in section, but is a tariff-defined term
SP 3.3.1.1(f)	Change "Existing Contract Rights" to "Existing Contract rights"	Not a tariff-defined term
SP 3.3.1.3	Change "two hours ahead" in the section to "two hours and fifteen minutes ahead" (3 places); change "two hours ahead" to "two hour and fifteen minute"	Correct section to conform with rest of SP 3.3.1, which concerns actions to be taken by two hours and fifteen minutes ahead of the Settlement Period
SP 3.3.1.3	Change "Existing Transmission Contract" to "Existing Contract"	The tariff-defined term is Existing Contracts
SP 3.3.1.3	Change "ETC" to "Existing Contract"	Correct use of tariff-defined term
SP 3.3.1.3	Change "New Firm Use" to "new firm use"	Not a tariff-defined term
SP 3.3.2(c)	Change "real time" to "real-time"	Correct grammar
SP 3.3.2(e)	Change "real time" to "real-time"	Correct grammar
SP 4.2.1(c)	Change "BEEP Interval" to "Settlement Interval"	Correct tariff-defined term is Settlement Interval
SP 4.2.1(c)	Change "real time" to "real-time"	Correct grammar

Section	Change	Reason for Change
SP 5.3	Change "no later than two hours before the close of the PX Day-Ahead Market for" to "no later than 5:00 am on the day before"	The PX and its markets are no longer operational; these changes are needed to accurately reflect the operation of the markets subsequent to the PX's stopping operations, and to implement changes to language in section to conform with similar changes in Section 2.2.12.2, *et seq.*, as approved in the proceeding concerning Amendment No. 56 to the ISO Tariff
SP 5.3	Add period to end of sentence	Punctuation needed in sentence
SP 7.5.1	Change "real time" to "real-time"	Correct grammar
SP 8.1	Change "Real Time" to "Real-Time"	Correct grammar
SP 9.3(d)	Change "Day-Ahead schedules" to "Day-Ahead Schedules"	Not capitalized in section, but is a tariff-defined term
SP 9.3(d), -(e)	Change "Hour-Ahead schedules" to "Hour-Ahead Schedules"	Not capitalized in section, but is a tariff-defined term
SP 9.5.2	Change "zonal" to "Zonal" (3 places)	Not capitalized in section, but is a tariff-defined term
SP 9.6.2	Change "zonal" to "Zonal" (3 places)	Not capitalized in section, but is a tariff-defined term
SP 9.7.1(a)	Change "Demands and external imports" to "Demands and external imports"	Delete extra space between "Demands" and "and"
SP 9.7.1(a)(ii)	Change "or Curtailable Demand's" to "Curtailable Demand's"	Correct extraneous use of the word "or"
SP 9.7.2	Change "Demand or" to "Demand or"	Delete extra space between words
SP 9.7.2	Change "zonal" to "Zonal" (3 places)	Not capitalized in section, but is a tariff-defined term
SP 9.8.1	Change "of a System Resources" to "of System Resources"	Correct incorrect use of the word "a"
SP 9.8.2	Change "zonal" to "Zonal" (3 places)	Not capitalized in section, but is a tariff-defined term
SP 10.2	Change "constraints" to "Constraints"	Not capitalized in section, but is a tariff-defined term
SP 10.2(a)	Change "redispatch cost" to "Redispatch cost"	Not capitalized in section, but is a tariff-defined term
SP 11	Change "REAL TIME" to	Correct grammar

Section	Change	Reason for Change
	"REAL-TIME"	
SP 11.1	Change "Energy bids" to "Energy Bids" (2 places)	Not capitalized in section, but is a tariff-defined term
SP 11.1	Change "real time" to "real-time"	Correct grammar
SP 11.1(b), -(c)	Change "Energy bids" to "Energy Bids"	Not capitalized in section, but is a tariff-defined term
SP 11.2	Change "BEEP (Balancing Energy and Ex-Post Pricing) Software" to "RTD Software"	The correct tariff-defined term is RTD Software
SP 11.2	Change "BEEP Software" to "RTD Software"	The correct tariff-defined term is RTD Software
SP 11.2	Change "BEEP Interval" to "Settlement Interval"	Correct tariff-defined term is Settlement Interval
SP 11.2	Change "real time" to "real-time"	Correct grammar
SP 11.2	Change "Energy bid" to "Energy Bid" (2 places); change "Energy bids" to "Energy Bids" (2 places)	Not capitalized in section, but is a tariff-defined term
SABP 1.2.2	Delete definitions of "Black Start Generator" and "ISO Home Page"	Definitions are duplicative of terms defined in the Master Definitions Supplement
SABP 1.2.2	Change "settlement" to "Settlement"	Not capitalized in section, but is a tariff-defined term
SABP 1.3.1	Change "settlement" to "Settlement"	Not capitalized in section, but is a tariff-defined term
SABP 2.1	Change "settlement" to "Settlement"	Not capitalized in section, but is a tariff-defined term
SABP 2.3.5	Change "market participants" to "Market Participants"	Not capitalized in section, but is a tariff-defined term
SABP 3.1(h)	Change "voltage support" to "Voltage Support"	Not capitalized in section, but is a tariff-defined term
SABP 3.1(h)	Change "long term" to "long-term"	Correct grammar
SABP 4.4.5	Change "ISOContact" to "ISO Contact"	Add needed space between words
SABP 4.5.1	Change "Settlement Statement re-run" to "Settlement Statement Re-run"	Not capitalized in section, but is a tariff-defined term
SABP 4.5.2	Change "Settlement Statement re-run" to "Settlement Statement Re-run"; "Settlement Statement re-runs" to	Not capitalized in section, but is a tariff-defined term

Section	Change	Reason for Change
	"Settlement Statement Re-runs"	
SABP 6.5.2(c)	Change "Interest be" to "Interest be"	Delete extra space from between words
SABP App. B, 1	Change "redispatch costs" to "Redispatch costs"	Not capitalized in section, but is a tariff-defined term
SABP App. B, 2.2	Change "Energy Bid" to "Energy bid"	In the context of the sentence in the section, word should be in lower-case type
SABP App. B, 2.4	Change "redispatch cost" to "Redispatch cost" (3 places) and "redispatch costs" to "Redispatch costs"	Not capitalized in section, but is a tariff-defined term
SABP App. B, 2.5	Change "redispatch costs" to "Redispatch costs"	Not capitalized in section, but is a tariff-defined term
SABP App. B, 2.6	Change "Exports" to "exports"	Not a tariff-defined term
SABP App. B, 2.6	Change "redispatch costs" to "Redispatch costs"	Not capitalized in section, but is a tariff-defined term
SABP App. B, 3.12	Change "redispatch" to "Redispatch"	Not capitalized in section, but is a tariff-defined term
SABP App. C, 1	Change "Real Time" to "real-time"	Correct grammar
SABP App. C, 1	Change "Ancillary Services Charges" to "Ancillary Services charges"	Not a tariff-defined term
SABP App. C, 1	Change "self provide" to "self-provide"	Correct grammar
SABP App. C, 2.1.1(a), -(b), -(c), -(d)	Change "zonal" to "Zonal" (4 places)	Not capitalized in section, but is a tariff-defined term
SABP App. C, 2.1.2(a), -(b), -(c), -(d)	Change "zonal" to "Zonal" (8 places)	Not capitalized in section, but is a tariff-defined term
SABP App. C, 2.2.1	Change "self provided" to "self-provided" (6 places)	Correct grammar
SABP App. C, 2.2.1	Change "Day-Ahead market" to "Day-Ahead Market"	Not capitalized in section, but is a tariff-defined term
SABP App. C, 2.2.1(a), -(b), -(c), -(d)	Change "zonal" to "Zonal" (6 places)	Not capitalized in section, but is a tariff-defined term
SABP App. C, 2.2.2	Change "self provided" to "self-provided" (6 places)	Correct grammar
SABP App. C, 2.2.2(a), -(b), -(c), -(d)	Change "zonal" to "Zonal" (6 places)	Not capitalized in section, but is a tariff-defined term
SABP App. C, 2.2.3	Change "self provision" to "self-provision"	Correct grammar
SABP App. C, 2.2.4(a)(i)	Insert space between "Ahead" and "Market"	Insert needed space between words

Section	Change	Reason for Change
SABP App. C, 2.2.4(a)(i)	Insert space between "Market" and "Clearing"	Correct typographical error
SABP App. C, 3.20A	Change "real time" to "real-time"	Correct grammar
SABP App. C, 3.26	Change "Day-Ahead market" to "Day-Ahead Market"	Not capitalized in section, but is a tariff-defined term
SABP App. C, 3.39.1	Change "zonal" to "Zonal"	Not capitalized in section, but is a tariff-defined term
SABP App. C, 3.40	Change "Day-Ahead market" to "Day-Ahead Market"	Not capitalized in section, but is a tariff-defined term
SABP App. C, 3.59	Change "zone" to "Zone"	Not capitalized in section, but is a tariff-defined term
SABP App. C, 3.61	Change "zone" to "Zone"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 2.1.1	Change "meter data" to "Meter Data"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 2.1.2	Change "Hour Ahead" to "Hour-Ahead"	Tariff-defined term incorrectly not hyphenated in section
SABP App. D, 2.2	Change "transmission losses" to "Transmission Losses"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 2.3	Change "Dispatch Interval Ex Post prices" to "Dispatch Interval Ex Post Prices"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 2.6	Change "real-time market" to "Real Time Market"	Not capitalized in section, but is a tariff-defined term; tariff-defined term is not hyphenated
SABP App. D, 2.6.1	Change "Ex Post price" to "Ex Post Price"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 2.6.1	Change "Non- Participating Load Agreement" to "Non-Participating Load Agreement"	Remove space between hyphenated words
SABP App. D, 2.6.2	Change "control area" to "Control Area"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 2.6.3	Change "Dispatch Interval Ex Post prices" to "Dispatch Interval Ex Post Prices"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 2.8	Change "Zonal Settlement Interval Ex Post price" to "Zonal Settlement Interval Ex Post Price"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 3.26	Change "UDC Service	Correct references in section to

Section	Change	Reason for Change
	Area" to "utility Service Area" (3 places)	indicate they apply to utilities, not simply UDCs
SABP App. D, 3.26	Change "Section 7.4.3" to "Section 7.4.2"	Correct section reference
SABP App. D, 3.49	Change "zone" to "Zone"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 3.49	Change "Ex-Post price" to "Ex Post Price"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 3.50	Change "Ex Post price" to "Ex Post Price"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 3.50	Change "zone" to "Zone"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 3.51	Change "Ex Post price" to "Ex Post Price"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 3.51	Change "resource-specific Ex Post price" to "Resource-Specific Settlement Interval Ex Post Price"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 3.52	Change "Settlement interval" to "Settlement Interval"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 3.56	Change "Settlement Periodly" to "Settlement Period"	Correct typographical error
SABP App. D, 3.58	Change "Dispatch interval" to "Dispatch Interval"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 3.59	Change "Dispatch interval" to "Dispatch Interval"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 3.61	Change "Settlement Periodly" to "Settlement Period"	Correct typographical erro
SABP App. D, 3.61	Change "Dispatch interval" to "Dispatch Interval"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 3.71	Change "Settlement interval" to "Settlement Interval"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 3.72	Change "Settlement interval" to "Settlement Interval"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 3.75	Change "ex post price" to "Ex Post Price"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 3.79	Change "real-time market" to "Real Time Market"	Not capitalized in section, but is a tariff-defined term; tariff-defined term is not hyphenated
SABP App. D, 3.86	Change "Settlement	Not capitalized in section, but is a

Section	Change	Reason for Change
	interval" to "Settlement Interval"	tariff-defined term
SABP App. D, 3.87	Change "an Settlement Periodly" to "a Settlement Period"	Correct typographical errors
SABP App. D, 3.93	Change "Dispatch interval" to "Dispatch Interval"	Not capitalized in section, but is a tariff-defined term
SABP App. D, 3.93	Change "sStack" to "Stack"	Correct typographical error
SABP App. D, 3.94	Change "Dispatch interval" to "Dispatch Interval"	Not capitalized in section, but is a tariff-defined term
SABP App. E, 2.3.3	Change "outage" to "Outage"	Not capitalized in section, but is a tariff-defined term
SABP App. E, 3.8	Change "Inter-Zonal interface" to "Inter-Zonal Interface"	Not capitalized in section, but is a tariff-defined term
SABP App. F, 1	Change "Revenue requirements" to "Revenue Requirements"	Not capitalized in section, but is a tariff-defined term
SABP App. F, 2.1.1	Change "section 7.1.4" to "Section 7.1.4"	Internal section references in the tariff/protocols are capitalized
SABP App. G, 1.2	Change "Reliability Must-Run contracts" to "Reliability Must-Run Contracts"	Not capitalized in section, but is a tariff-defined term
SABP App. G, 1.2	Change "short term" to "short-term"	Correct grammar
SABP App. G, 1.2	Change "long term" to "long-term"	Correct grammar
SABP App. G, 2.1.1	Change "G.2.1.1" to "G 2.1.1"	Correct typographical error
SABP App. G, 2.1.2	Change "Long term" to "Long-term"	Correct grammar
SABP App. G, 2.2.1	Change "voltage support" to "Voltage Support" (2 places)	Not capitalized in section, but is a tariff-defined term
SABP App. G, 2.2.1	Change "long term" to "long-term"	Correct grammar
SABP App. G, 2.2.1	Change "G.2.1.1" to "G 2.1.1"	Correct typographical error
SABP App. G, 2.2.1	Change "G2.1.1" to "G 2.1.1"	Insert needed space
SABP App. G, 2.2.1	Change "G2.1.2" to "G 2.1.2"	Insert needed space
SABP App. G, 2.2.2	Change "long term" to "long-term"	Correct grammar
SABP App. G, 2.2.2	Change "G2.1.1" to	Insert needed space

Section	Change	Reason for Change
	"G 2.1.1"	
SABP App. G, 2.2.2	Change "G2.1.2" to "G 2.1.2"	Insert needed space
SABP App. G, 2.2.2	Change "($)payable" to "($) payable"	Correct typographical error
SABP App. G, 2.2.2	Change "voltage support" to "Voltage Support"	Not capitalized in section, but is a tariff-defined term
SABP App. G, 2.4.1	Change "G2.3.1" to "G 2.3.1"	Insert needed space
SABP App. G, 2.4.1	Change "G2.3.2" to "G 2.3.2"	Insert needed space
SABP App. G, 2.4.2	Change "G2.3.1" to "G 2.3.2"	Insert needed space
SABP App. G, 2.4.2	Change "G2.3.2" to "G 2.3.2"	Insert needed space
SABP App. G, 3.2	Change "Hourly Ex Post price" to "Hourly Ex Post Price"	Not capitalized in section, but is a tariff-defined term
SABP App. G, 3.3	Change "short term" to "short-term"	Correct grammar
SABP App. G, 3.4	Change "short term" to "short-term"	Correct grammar
SABP App. G, 3.7	Change "voltage support" to "Voltage Support"	Not capitalized in section, but is a tariff-defined term
SABP App. G, 3.7	Change "long term" to "long-term"	Correct grammar
SABP App. G, 3.10	Change "voltage support" to "Voltage Support"	Not capitalized in section, but is a tariff-defined term
SABP App. G, 3.10	Change "long term" to "long-term"	Correct grammar
SABP App. G, 3.15	Change "Payment" to "payment"	Not a tariff-defined term
SABP Annex 1, 1.2.3	Delete definitions of "ISO Home Page," "ISO Invoice," "Revised Adjusted RMR Invoice," and "Revised Estimated RMR Invoice"	Definitions are duplicative of terms defined in the Master Definitions Supplement
SABP Annex 1, 1.2.3	Delete definitions of "RMR Charge" and "RMR Contract"	Definitions are proposed to be adapted in definitions of terms "Reliability Must-Run Charge" and "Reliability Must-Run Contract (RMR Contract)" in the Master Definitions Supplement
SABP Annex 1, 1.2.3	Change "section 3" to "Section 3"	Internal section references in the tariff/protocols are capitalized
MP 1.2.2	Delete definitions of "ISO Home Page," "Scheduling Coordinator Metered	Definitions are duplicative of terms defined in the Master Definitions Supplement

Section	Change	Reason for Change
	Entity," and "SC Metered Entity"	
MP 1.2.2	Delete definition of "ISO Authorized Inspector"	Definitions is proposed to be adapted in definitions of same term in the Master Definitions Supplement
MP 1.2.2	Delete definition of "ISO Metered Entity"	Definition is outdated version of term defined in Master Definitions Supplement
MP 1.2.2	Delete definition of "MCI Connected Entity Package"	Remove outdated reference
MP 1.2.3(e)	Change "business day" to "Business Day"	Not capitalized in section, but is a tariff-defined term
MP 2.2.5	Change "business days" to "Business Days"	Not capitalized in section, but is a tariff-defined term
MP 2.2.5	Change "available to" to "available to"	Remove extra space between words
MP 3.3.4	Change "business days" to "Business Days"	Not capitalized in section, but is a tariff-defined term
MP 3.3.5	Change "business days" to "Business Days"	Not capitalized in section, but is a tariff-defined term
MP 4.2.1	Change numbering of section so that MP 4.2.1(c) is listed instead as MP 4.2.1(b)	Correct section numbering
MP 5.1.3(a), -(b)	Change "business days" to "Business Days"	Not capitalized in section, but is a tariff-defined term
MP 5.1.7	Change "business days" to "Business Days"	Not capitalized in section, but is a tariff-defined term
MP 6.1.2(b)	Change "business days" to "Business Days"	Not capitalized in section, but is a tariff-defined term
MP 11.2	Delete "The detailed requirements for this interface are described in the MCI Connected Entity Package."	Remove outdated reference
MP 12.1	Change "business days" to "Business Days" (2 places)	Not capitalized in section, but is a tariff-defined term
MP 13.3	Change "business days" to "Business Days" (5 places)	Not capitalized in section, but is a tariff-defined term
MP App. A, 2.1	Change "Wenet" to "WEnet"	Correct misspelling
MP App. G, 1.1	Change "Wenet" to "WEnet"	Correct misspelling
EIRP 1.2.2	Change "Preferred Hour Ahead Schedule" to	Defined term should be hyphenated

Section	Change	Reason for Change
	"Preferred Hour-Ahead Schedule"	
EIRP 1.2.2	Change "Hour Ahead" to "Hour-Ahead" (2 places)	Defined terms should be hyphenated
EIRP 2.4.1	Change "ISO markets" to "ISO Markets"	Not capitalized in section, but is a tariff-defined term
EIRP 4.1	Change "Hour Ahead" to "Hour-Ahead"	Defined term should be hyphenated
EIRP 5.1	Change "Preferred Hour Ahead Energy Schedules" to "Preferred Hour-Ahead Schedules for Energy"	Correct use of tariff-defined terms, and defined term should be hyphenated
UAP 2	Change "uninstructed deviation penalties" to "Uninstructed Deviation Penalties"	Not capitalized in section, but is a tariff-defined term
UAP 3.1.2	Change "constraints" to "Constraints"	Not capitalized in section, but is a tariff-defined term
UAP 3.1.2(e)	Change "congestion zones" to "Congestion Zones"	Not capitalized in section, but are tariff-defined terms
UAP 3.1.2(4)	Change "-intra-zonal" to "intra-zonal"	Correct grammar

ATTACHMENT B

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2.2.2 ISO Scheduling Responsibilities.

To fulfill its obligations with respect to scheduling Energy and Ancillary Services, the ISO shall:

(a) provide Scheduling Coordinators with operating information and system status on a Day-Ahead and Hour-Ahead, Zonal and/or Scheduling Point basis to enable Scheduling Coordinators to optimize Generation, Demand and the provision of Ancillary Services;

(b) determine whether Preferred Schedules submitted by Scheduling Coordinators meet the requirements of Section 2.2.7.2, and whether they will cause Congestion;

(c) prepare Suggested Adjusted Schedules on a Day-Ahead basis and Final Schedules on a Day-Ahead and Hour-Ahead basis;

(d) validate all Ancillary Services bids and self-provided Ancillary Services;

(e) reduce or eliminate Inter-Zonal Congestion based on Adjustment Bids and in accordance with the Congestion Management procedures, and Intra-Zonal Congestion in accordance with Section 7.2.6; and

(f) if necessary, make mandatory adjustments to Schedules in accordance with the Congestion Management procedures.

***

2.2.3.2 The creditworthiness requirements in this section apply to the ISO's acceptance of Schedules and to all transactions in an ISO Market. Each Scheduling Coordinator, UDC or MSS shall either maintain an Approved Credit Rating (which may differ for different types of transactions with the ISO) or provide in favor of the ISO one of the following forms of security for an amount to be determined by the Scheduling Coordinator, UDC or MSS and notified to the ISO under Section 2.2.7.3:

(a) an irrevocable and unconditional letter of credit confirmed by a bank or financial institution reasonably acceptable to the ISO;

(b) an irrevocable and unconditional surety bond posted by an insurance company reasonably acceptable to the ISO;

(c) an unconditional and irrevocable guarantee by a company which has and maintains an Approved Credit Rating;

(d) a cash deposit standing to the credit of an interest bearing escrow account maintained at a bank or financial institution designated by the ISO;

(e) a certificate of deposit in the name of the ISO from a financial institution designated by the ISO; or

(f) a payment bond certificate in the name of the ISO from a financial institution designated by the ISO.

Letters of credit, guarantees, surety bonds, payment bond certificates, escrow agreements and certificates of deposit must cover all applicable outstanding and estimated liabilities under Section 2.2.7.3 and shall be in such form as the ISO may reasonably require from time to time by notice to Scheduling Coordinators, UDCs or MSSs. A Scheduling Coordinator, UDC or MSS which does not maintain an Approved Credit Rating shall be subject to the limitations on trading set out in Section 2.2.7.3. Notwithstanding anything to the contrary in the ISO Tariff, a Scheduling Coordinator or UDC that had an Approved Credit Rating on January 3, 2001, and is an Original Participating Transmission Owner or is a Scheduling Coordinator for an Original Participating Transmission Owner shall not be precluded by Section 2.2.7.3 from scheduling transactions that serve a UDC's Demand~~Load~~ from –

(1) a resource that the UDC owns; and

(2) a resource that the UDC has under contract to serve its Demand~~Load~~.

***

2.2.4.5.1 Pending acceptance of termination of service pursuant to Section 2.2.4.6.1 by FERC, the ISO will suspend the certification of a Scheduling Coordinator which has received a notice of termination

under Section 2.2.4.5(a) and the Scheduling Coordinator will not be eligible to submit ~~s~~Schedules and bids for Energy and Ancillary Services to the ISO.

***

2.2.6.11 Participating Intermittent Resources. Submitting Schedules consistent with the ISO ~~p~~Protocols; and

***

2.2.7.3 Limitation on Trading. A Scheduling Coordinator, UDC or MSS that does not maintain an Approved Credit Rating, as defined with respect to either payment of the Grid Management Charge, or payment of other charges, shall maintain security in accordance with Section 2.2.3.2. For the avoidance of doubt, the ISO Security Amount is intended to cover the entity's outstanding and estimated liability for either (i) Grid Management Charge; and/or (ii) Imbalance Energy, Ancillary Services, Grid Operations Charge, Wheeling Access Charge, High Voltage Access Charge, Transition Charge, Usage Charges, and FERC Annual Charges. Each Scheduling Coordinator, UDC or MSS required to provide an ISO Security Amount under Section 2.2.3.2 shall notify the ISO of the initial ISO Security Amount (separated into amounts securing payment of the Grid Management Charge and amounts securing payments of other charges) that it wishes to provide at least fifteen (15) days in advance and shall ensure that the ISO has received such ISO Security Amount prior to the date the Scheduling Coordinator commences trading or the UDC or MSS commences receiving bills for the High Voltage Access Charge and Transition Charge. A Scheduling Coordinator, UDC or MSS may at any time increase its ISO Security Amount by providing additional guarantees or credit support in accordance with Section 2.2.3.2. A Scheduling Coordinator, UDC or MSS may reduce its ISO Security Amount by giving the ISO not less than fifteen (15) days notice of the reduction, provided that the Scheduling Coordinator, UDC or MSS is not then in breach of this Section 2.2.7.3. The ISO shall release, or permit a reduction in the amount of,

such guarantees or other credit support required to give effect to a permitted reduction in the ISO Security Amount as the Scheduling Coordinator, UDC or MSS may select.

Following the date on which a Scheduling Coordinator commences trading, the Scheduling Coordinator shall not be entitled to submit a Schedule to the ISO and the ISO may reject any Schedule submitted if, at the time of submission, the Scheduling Coordinator's ISO Security Amount is exceeded by the Scheduling Coordinator's estimated aggregate liability for (i) Grid Management Charge and/or Imbalance Energy, Ancillary Services, Grid Operations Charge, Wheeling Access Charge, Usage Charges, and FERC Annual Charges on each Trading Day for which Settlement has not yet been made in accordance with Section 11.3.1 and the Scheduling Coordinator's estimated liability for High Voltage Access Charge and Transition Charge for which Settlement has not yet been made in accordance with Section 11.3. The ISO shall notify a Scheduling Coordinator if at any time such outstanding liabilities exceed 90% of the relevant portion of the ISO Security Amount. For the purposes of calculating the Scheduling Coordinator's estimated aggregate liability, the estimate shall include (1) outstanding charges for Trading Days for which Settlement data is available, and (2) an estimate of charges for Trading Days for which Settlement data is not yet available. To estimate charges for Trading Days for which Settlement data is not yet available, the ISO will consider available historical Settlement data, appropriately adjusted to reflect recent market prices and trends, or other available information for individual Scheduling Coordinators.

Following the date on which a UDC or MSS commences operation, the UDC's or MSS's Scheduling Coordinator shall not be entitled to submit a Schedule to the ISO and the ISO may reject any Schedule submitted if, at the time of submission, the UDC's or MSS's ISO Security Amount is exceeded by the UDC's or MSS's estimated aggregate liability for Grid Management Charge, and/or High Voltage Access Charges and Transition Charges for which Settlement has not yet been made in accordance with Section 11.3. The ISO shall notify a UDC or MSS if at any time such outstanding liabilities exceed 90% of the relevant portion of the ISO Security Amount. For the purposes of estimating the UDC's or MSS's aggregate liability for High Voltage Access Charges and Transition Charges, the UDC's or MSS's liability shall be equal to the billed Demand use~~Load~~ (in MWh) for a month in the UDC's or MSS's Service Area (including exports from the Service Area) multiplied by the ISO's estimated High Voltage Access Charge

and Transition Charge for that month, as such estimated cost is notified by the ISO to UDCs and MSSs from time to time.

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2.2.8.1 Preferred Schedule. A Preferred Schedule shall be submitted by each Scheduling Coordinator on a daily and/or hourly basis to the ISO. Scheduling Coordinators may also submit to the ISO, Ancillary Services bids in accordance with Section 2.5.10 and, where they elect to self-provide Ancillary Services pursuant to Section 2.5.20.1, an Ancillary Service schedule meeting the requirements set forth in Section 2.5.20.6. The Preferred Schedule shall also include an indication of which resources (Generation or Load) if any may be adjusted by the ISO to eliminate Congestion. On receipt of the Preferred Schedule in the Day-Ahead scheduling process, the ISO shall notify the Scheduling Coordinator of any specific Reliability Must-Run Units which have not been included in the Preferred Schedule but which the ISO requires to run in the next Trading Day. The ISO will also notify the Scheduling Coordinator of any Ancillary Services it requires from specific Reliability Must-Run Units under their Reliability Must-Run Contracts in the next Trading Day. If the ISO identifies mismatches in the scheduled quantity or location for any Inter-Scheduling Coordinator Energy Trade, it will notify the Scheduling Coordinators concerned and give them until a specified time, which will allow them approximately one half-hour, in which to modify their Schedules to resolve the mismatch before it applies the provisions of Section 2.2.11.3.4. If the ISO notifies a Scheduling Coordinator that there will be no Congestion on the ISO Controlled Grid and, subject to Section 2.2.11.3.4, the Preferred Schedule shall become that Scheduling Coordinator's Final Schedule.

***

2.2.10 Information to be Provided by the ISO to all Scheduling Coordinfators.

By 6:00 p.m. two days prior to a Trading Day, the ISO shall publish on WEnet information, including the following to all Scheduling Coordinators for each Settlement Period of the Trading Day:

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2.2.10.3 Forecast Loop-_Flow. Forecast Loop Flow over ISO Inter-~~z~~Zonal Interfaces and Scheduling Points;

***

2.2.11.1 For DemandLoad:

2.2.11.1.1 Designated Location Code. For all DemandLoad the Location Code of the Take-Out Point;

***

2.2.11.4 For Self-Provided Ancillary Services: Scheduling Coordinators electing to self-provide Ancillary Services shall supply the information referred to in Section 2.5.20.5 in relation to each Ancillary Service to be self-provided.

2.2.11.5 For Interruptible Imports: the quantity (in MWh) of Energy categorized as Interruptible Imports and whether the Scheduling Coordinator intends to self-provide the Operating Reserve required by Section 2.5.3.2 to cover such Interruptible Imports or to purchase such Operating Reserve from the ISO.

***

2.2.12.2.3.1 For each hour for which an Applicable RMR Owner has selected the Market Option ~~("Market Hour")~~, the Applicable RMR Owner (i) may bid into a power exchange ~~the PX Day-Ahead M~~market any amount of the RMR Market Energy and (ii) may schedule as a bilateral Day-Ahead transaction any amount of RMR Market Energy.

The Preferred Day-Ahead Schedule of the Applicable RMR SC shall include as RMR Market Energy for each ~~Market H~~hour the sum of the amount awarded to the Applicable RMR Owner in ~~the PX Day-Ahead~~any power exchange ~~M~~market for that ~~Market H~~hour and the amount scheduled as a bilateral Day-Ahead transaction for that ~~Market H~~hour. If the Preferred Day-Ahead Schedule of the Applicable RMR SC for any ~~Market H~~hour includes Adjustment Bids for the RMR Unit, the Adjustment Bid shall specify the RMR Market Energy as the minimum MW output to which the Applicable RMR SC will allow the RMR Unit to be redispatched for that ~~Market H~~hour.

Notwithstanding anything to the contrary in the RMR Contract, neither the Applicable RMR Owner nor the Applicable RMR SC shall be entitled to any payment from any source for RMR Market Energy that is not bid and scheduled as required by this Section 2.2.12.2.3~~2~~. In the event that the RMR Market Energy is not delivered, (i) if the RMR Market Energy had been scheduled, the Applicable RMR Owner shall not be entitled to an Availability Payment under the RMR Contract and the Applicable RMR SC shall pay for the Imbalance Energy necessary to replace that RMR Market Energy, or (ii) if the RMR Market Energy had not been scheduled, the Applicable RMR Owner shall not be entitled to an Availability Payment under the RMR Contract and, if the variable costs saved by the Owner's failure to deliver the RMR Market Energy (which shall be equal to the Variable Cost Payment determined pursuant to Schedule C in the RMR Contract) are greater than the foregone Availability Payment under the RMR Contract, the Applicable RMR Owner shall pay the difference between the variable costs saved and the Availability Payment.

2.2.12.2.3.2 If the Applicable RMR SC's Preferred Day-Ahead Schedule does not include the entire amount of RMR Market Energy for any ~~Market H~~hour, the Applicable RMR Owner shall bid all remaining RMR Market Energy for that ~~Market H~~hour, net of any RMR Energy the Applicable RMR Owner elects to

provide through an Hour-Ahead bilateral transaction for that ~~Market H~~hour, into the next available ~~PX M~~power exchange market for such hour at zero dollars per MWh.

2.2.12.2.3.2.1 The Applicable RMR SC's Preferred Hour-Ahead Schedule for each ~~Market H~~hour shall include all RMR Market Energy specified in the RMR Dispatch Notice for that ~~Market H~~hour, except for the amount of RMR Energy that the Applicable RMR Owner was required to bid into the ~~PX~~power exchange ~~M~~markets under Section 2.2.12.2.3.2 but was not awarded in such ~~PX M~~power exchange markets for such hour. If the Preferred Hour-Ahead Schedule of the Applicable RMR SC for any ~~Market H~~hour includes Adjustment Bids for the RMR Unit, the Adjustment Bid shall specify the RMR Market Energy as the minimum MW output to which the Applicable RMR SC will allow the RMR Unit to be redispatched for that ~~Market H~~hour.

2.2.12.2.3.3 Whether or not the RMR Energy is in a Final Schedule, the Applicable RMR Owner must deliver the RMR Energy pursuant to the RMR Dispatch Notice. If the RMR Owner has bid and scheduled the RMR Energy as required by this Section 2.2.12.2.3, any RMR Energy provided but not included in the Final Schedule will be paid as Uninstructed Imbalance Energy. Notwithstanding anything to the contrary in the RMR Contract, neither the Applicable RMR Owner nor the Applicable RMR SC shall be entitled to any payment from any source for RMR Market Energy that is not bid and scheduled as required by this Section 2.2.12.2.3.

***

2.2.12.3 ~~Non-PX~~ Demand Information. By 6:00 a.m. on the day preceding the Trading Day, each Scheduling Coordinator ~~(other than the PX)~~ shall provide to the ISO a Demand Forecast specified by UDC Service Area for which it will schedule deliveries for each of the Settlement Periods of the following Trading Day. The ISO shall aggregate the Demand information by UDC Service Area and transmit the aggregate Demand information to each UDC serving such aggregate Demand.

***

2.2.13.1 Submission of Preferred Schedule. Each Scheduling Coordinator's Preferred Schedule for each Settlement Period during a Trading Day together with any additional or updated Adjustment Bids or Ancillary Services ~~B~~bids shall be submitted at least two hours and fifteen minutes (*i.e.*, 135 minutes) prior to the commencement of that Settlement Period.

***

2.2.13.2.2 Congestion Management Provisions for Final Hour-Ahead Schedules. If the ISO identifies Congestion, it shall use the Congestion Management provisions of Section 7.2 of this ISO Tariff and the ISO Scheduling Protocol to develop the Final Hour-Ahead Schedules.

***

2.2.17 Relationship Between ISO and Eligible Intermittent Resources and Between the ISO and Participating Intermittent Resources

The ISO shall not schedule Energy from an Eligible Intermittent Resource other than through a Scheduling Coordinator. Settlement with Participating Intermittent Resources that meet the scheduling obligations established in the ISO ~~p~~Protocols shall be as provided in this ISO Tariff. No a~~A~~djustment ~~b~~Bids or Supplemental Energy bids may be submitted on behalf of Participating Intermittent Resources. Any Eligible Intermittent Resource that is not a Participating Intermittent Resource, or any Participating Intermittent Resource for which Adjustment Bids or Supplemental Energy bids are submitted, or that fails to meet the scheduling obligations established in the ISO Protocols, shall be scheduled and settled as a Generating Unit for the associated Settlement Periods (except that the Forecasting Fee shall apply in such Settlement Periods).

***

2.3.1.1.1 Establish ISO Control Center. The ISO shall establish a WSECC approved Control Area and control center to direct the operation of all facilities forming part of the ISO Controlled Grid, Reliability Must-Run Units and Generating Units providing Ancillary Services.

***

2.3.1.1.3 ISO Control Center Authorities. The ISO shall have full authority, subject to Section 2.3.1.2, to direct the operation of the facilities referred to in Section 2.3.1.1.2 including (without limitation), to:

(a) direct the physical operation by the Participating TOs of transmission facilities under the Operational Control of the ISO, including (without limitation) circuit breakers, switches, voltage control equipment, protective relays, metering, and Load Shedding equipment;

(b) commit and dispatch Reliability Must-Run Units;

(c) order a change in operating status of auxiliary equipment required to control voltage or frequency;

(d) take any action it considers to be necessary consistent with Good Utility Practice to protect against uncontrolled losses of Load or Generation and/or equipment damage resulting from unforeseen occurrences;

(e) control the output of Generating Units that are selected to provide Ancillary Services and Imbalance Energy;

(f) dispatch Loads through direct Load control or other means at the ISO's discretion that are curtailable as an Ancillary Service; and

(g) procure Supplemental Energy.

***

2.3.1.1.6 The ISO shall be the WSECC ~~secur~~reliability coordinator for the ISO Controlled Grid.

***

2.3.1.3.1 The ISO shall exercise Operational Control over the ISO Controlled Grid to meet planning and Operating Reserve criteria no less stringent than those established by WSECC and NERC as those standards may be modified from time to time, and Local Reliability Criteria that are in existence on the ISO Operations Date and have been submitted to the ISO by each Participating TO pursuant to Section 2.2.1(v) of the TCA. All Market Participants and the ISO shall comply with the ISO ~~r~~Reliability ~~c~~Criteria, standards, and procedures.

2.3.1.3.2 The ISO may establish planning and Operating Reserve criteria more stringent than those established by WSECC and NERC or revise the Local Reliability Criteria subject to and in accordance with the provisions of the TCA.

***

2.3.2.2 Emergency Procedures. In the event of a System Emergency, the ISO shall take such action as it considers necessary to preserve or restore stable operation of the ISO Controlled Grid. The ISO shall act in accordance with Good Utility Practice to preserve or restore reliable, safe and efficient service as quickly as reasonably practicable. The ISO shall keep system operators in adjacent Control Areas informed as to the nature and extent of the System Emergency in accordance with WSECC procedures and, where practicable, shall additionally keep the Market Participants within the Control Area informed.

***

2.3.2.3.2 Before any such intervention the ISO must (in the following order): (a) dispatch all scheduled Generation and all other Generation offered or available to it regardless of price (including all Adjustment Bids, Supplemental Energy bids, Ancillary Services and reserves); (b) dispatch all interruptible ILoads made available by UDCs to the ISO in accordance with the relevant agreements with UDCs; (c) dispatch or curtail all price-responsive Demand that has been bid into any of the markets and exercise its rights under all load curtailment contracts available to it; (d) exercise Load Shedding to curtail Demand on an involuntary basis to the extent that the ISO considers necessary.

***

2.3.2.8.2 **Load Curtailment.** A Scheduling Coordinator may specify that Loads will be reduced at specified Market Clearing Prices or offer the right to exercise Load curtailment to the ISO as an Ancillary Service or utilize Load curtailment itself (by way of self-provision of Ancillary Services) as Non-Spinning Reserve or Replacement Reserve. The ISO, at its discretion, may require direct control over such Curtailable Demand to assume response capability for managing System Emergencies. However, non-firm Loads shall not be eligible to provide Curtailable Demand if they are receiving incentives for interruption under existing programs approved by a Local Regulatory Authority, unless: a) participation in the ISO's Ancillary Services markets is specifically authorized by such Local Regulatory Authority, and b) there exist no contingencies on the availability, nor any unmitigated incentives encouraging prior curtailment, of such interruptible Load for Dispatch as Curtailable Demand as a result of the operation of such existing program.The ISO may establish standards for automatic communication of curtailment instructions to implement Load curtailment as a condition for accepting any offered Curtailable Demand as an Ancillary Service.

***

2.3.3.3 Requests for Outages in Real-Time Operation. Requests for Outages of: (i) facilities that comprise the ISO Controlled Grid or (ii) Participating Generators in real-time operation shall be made by the Operator to the ISO Control Center. The ISO will not approve any Outage request made within seventy-two (72) hours of the requested Outage start time unless: (i) the requested Outage could not have been reasonably foreseen and scheduled through the Outage coordination process provided in Section 2.3.3; and (ii) the requested Outage will not compromise ISO Controlled Grid reliability.

***

2.3.3.5 Maintenance Outage Planning. Each Operator shall, by not later than October 15 each year, provide the ISO with a proposed schedule of all Maintenance Outages it wishes to undertake in the following year. The proposed schedule shall include all of the Operator's transmission facilities that comprise the ISO Controlled Grid and Participating Generators. In the case of a Participating TO's transmission facilties, that proposed schedule shall be developed in consultation with the UDCs interconnected with that Participating TO's system and shall take account of each UDC's planned maintenance requirements. The nature of the information to be provided and the detailed Maintenance Outage ~~p~~Planning ~~p~~Procedure shall be established by the ISO and set out in an ISO Protocol. Either the ISO, pursuant to Section 2.3.3.6, or an Operator, subject to Section 2.3.3.5.4, may at any time request a change to an Approved Maintenance Outage. An Operator may, upon seventy-two (72) hours advance notice, schedule with the ISO Outage Coordination Office a Maintenance Outage on its system, subject to the conditions of Sections 2.3.3.5.1, 2.3.3.5.2, and 2.3.3.5.3.

***

2.3.3.6 Maintenance Outage Requests by the ISO. The ISO Outage Coordination Office may at any time request a Maintenance Outage or a change to an Approved Maintenance Outage from an Operator if, in the opinion of the ISO Outage Coordination Office, the requested Maintenance Outage or change is required to secure the efficient use and reliable operation of the ISO Controlled Grid. In addition, the ISO Outage

Coordination Office may, by providing notice no later than 5:00 a.m. of the day prior to the day upon which the Outage is scheduled to commence, direct the Operator to cancel an Approved Maintenance Outage, when necessary to preserve or maintain System Reliability or, with respect to Reliability Must-Run Units or facilities that form part of the ISO Controlled Grid, to avoid unduly significant market impacts that would arise of the Outage were to proceed as scheduled. The Operator, acting in accordance with Good Utility Practice, shall comply with the ISO's direction and the provisions of Sections 2.3.3.6.1 and 2.3.3.6.2 shall apply. The ISO shall give notice of any such direction to Market Participants prior to the deadline for submission of initial Preferred Day-Ahead Schedules for the day on which the Outage was to have commenced. For purposes of this section and Section 2.3.3.3, an "unduly significant market impact" means an unplanned event or circumstance (e.g., unseasonable weather, a Forced Outage of a facility, or other occurrence) that adversely affects the competitive nature and efficient workings of the ISO ~~m~~Markets, and is of such severity that a prudent Operator would not have scheduled a Maintenance Outage of its facility if the unplanned event or circumstance could have been anticipated.

***

2.3.3.9.5 Within forty-eight (48) hours of the commencement of a Forced Outage, the Operator shall provide to the ISO an explanation of the Forced Outage, including a description of the equipment failure or other cause and a description of all remedial actions taken by the Operator. Upon request of the ISO, Operators, and where applicable, Eligible Customers, Scheduling Coordinators, UDCs and MSSs promptly shall provide information requested by the ISO to enable the ISO to review the explanation submitted by the Operator and to prepare reports on Forced Outages. If the ISO determines that any Forced Outage may have been the result of gaming or other questionable behavior by the Operator, the ISO shall submit a report describing the basis for its determination to the FERC. The ISO shall consider the following factors when evaluating the Forced Outage to determine if the Forced Outage was the result of gaming or other questionable behavior by the ~~o~~Operator: 1) if the Forced Outage coincided with certain market conditions such that the Forced Outage may have influenced market prices or the cost of payments associated with out-of-sequence dispatches, out-of-market

dispatches, or Real Time Market dispatches above the Marginal Proxy Clearing Price or Non-Emergency Clearing Price Limit, as applicable; 2) if the Forced Outage coincided with a change in the bids submitted for any units or resources controlled by the Operator or the Operator's Scheduling Coordinator; 3) if the ISO had recently rejected a request for an outage for, or to shut down, the Generating

Unit experiencing the Forced Outage; 4) if the timing or content of the notice of the Forced Outage provided to the ISO was inconsistent with subsequent reports of or the actual cause of the outage; 5) if the Forced Outage or the duration of the Forced Outage was inconsistent with the history or past performance of that Generating Unit or similar Generating Units; 6) if the Forced Outage created or exacerbated ~~c~~Congestion; 7) if the Forced Outage was extended with little or no notice; 8) if the Operator had other alternatives to resolve the problems leading to the Forced Outage; 9) if the Operator took reasonable action to minimize the duration of the Forced Outage; or 10) if the Operator failed to provide the ISO an explanation of the Forced Outage within forty-eight (48) hours or failed to provide any additional information or access to the generating facility requested by the ISO within a reasonable time.

***

2.3.4 Management of Overgeneration Conditions.

The ISO's management of Overgeneration relates only to real time. Overgeneration in real time will be mitigated by the ISO as follows; provided that the ISO ~~o~~Operator will have the discretion, if necessary to avoid a ~~s~~System ~~e~~Emergency, to eliminate one or more of the following steps.

***

2.3.5.1.2 If the forecast shows that the applicable W~~S~~ECC/NERC Reliability Criteria can be met during peak DemandL~~oad~~ periods, then the ISO shall take no further action.

2.3.5.1.3 If the forecast shows that the applicable WS~~E~~ECC/NERC Reliability Criteria cannot be met during peak Demand~~Load~~ periods, then the ISO shall facilitate the development of market mechanisms to bring the ISO Controlled Grid during peak periods into compliance with the Applicable Reliability Criteria (or such more stringent criteria as the ISO may impose pursuant to Section 2.3.1.3.2). The ISO shall solicit bids for Replacement Reserves in the form of Ancillary Services, short-term Generation supply contracts of up to one (1) year with Generators, and Load curtailment contracts giving the ISO the right to reduce the ~~Loa~~Demands of those parties that win the contracts when there is insufficient Generation capacity to satisfy those ~~Loa~~Demands in addition to all other ~~Loa~~Demands. The curtailment contracts shall provide that the ISO's curtailment rights can only be exercised after all available Generation capacity has been fully utilized unless the exercise of such rights would allow the ISO to satisfy the Applicable Reliability Criteria at lower cost, and the curtailment rights shall not be exercised to stabilize or otherwise influence prices for power in the Energy markets.

2.3.5.1.4 If Replacement Reserves, short-term Generation supply contracts or curtailment contracts are required to meet Applicable Reliability Criteria, the ISO shall select the bids that permit the satisfaction of those Applicable Reliability Criteria at the lowest cost.

***

2.3.5.1.6 The ISO may, in addition to the required annual forecast, publish a forecast of the peak ~~loa~~Demands and Generation resources for two or more additional years. This forecast would be for information purposes to allow Market Participants to take appropriate steps to satisfy the Applicable Reliability Criteria, and would not be used by the ISO to determine whether additional resources are necessary.

***

2.3.5.1.8 Except where and to the extent that such costs are recovered from Scheduling Coordinators pursuant to Section 2.5, and except as provided in Section 2.3.5.1.9, all costs incurred by the ISO in any hour pursuant to any contract entered into under this Section 2.3.5.1 shall be charged to each Scheduling Coordinator pro rata based upon the same proportion as the Scheduling Coordinan~~a~~tor's metered hourly Demand (including exports) bears to the total metered hourly Demand (including exports) served in that hour.

***

2.4.4.1.1 The transmission service rights and obligations of Non-Participating TOs under Existing Contracts, including all terms, conditions and rates of the Existing Contracts, as they may change from time to time under the terms of the Existing Contracts, will continue to be honored by the parties to those contracts, for the duration of those contracts. For the purpose of Section 2.4.4, the transmission service rights of ~~n~~Non-Participating TOs are called "Existing Rights."

2.5 Ancillary Services.

2.5.1 Scope.

The ISO shall be responsible for ensuring that there are sufficient Ancillary Services available to maintain the reliability of the ISO Controlled Grid consistent with WSECC and NERC criteria. The ISO's Ancillary Services requirements may be self-provided by Scheduling Coordinators. Those Ancillary Services which the ISO requires to be available but which are not being self-provided will be competitively procured by the ISO from Scheduling Coordinators in the Day-Ahead Market, Hour-Ahead Market and in real time or by longer-term contracts. The ISO will manage both ISO procured and self-provided Ancillary Services as part of the real-time dDispatch. The ISO will calculate payments for Ancillary Services to Scheduling Coordinators and charge the cost to Scheduling Coordinators.

For purposes of this ISO Tariff, Ancillary Services are: (i) Regulation, (ii) Spinning Reserve, (iii) Non-Spinning Reserve, (iv) Replacement Reserve, (v) Voltage Support, and (vi) Black Start capability. Bids for Non-Spinning Reserve and Replacement Reserve may be submitted by the Demand-side as well as by owners of Generation. Identification of specific services in this ISO Tariff shall not preclude development of additional interconnected operation services over time. The ISO and Market Participants will seek to develop additional categories of these unbundled services over time as the operation of the ISO Controlled Grid matures.

* * *

2.5.2.1 Determination of Ancillary Service Standards. The ISO shall set the required standard for each Ancillary Service necessary to maintain the reliable operation of the ISO Controlled Grid. Ancillary Services standards shall be based on WSECC Minimum Operating Reliability Criteria (MORC) and ISO Controlled Grid reliability requirements. The ISO Grid Operations Committee, in conjunction with the relevant reliability council (WSECC), shall

develop these Ancillary Services standards to determine reasonableness, cost effectiveness, and adherence to national and WSECC standards. The standards developed by the ISO shall be used as a basis for determining the quantity and type of each Ancillary Service which the ISO requires to be available.

2.5.2.2 Time-frame For Revising Ancillary Service Standards. The ISO Technical Advisory Committee shall periodically undertake a review of the ISO Controlled Grid operation to determine any revision to the Ancillary Services standards to be used in the ISO Control Area. At a minimum the ISO Grid Operations Committee shall conduct such reviews to accommodate revisions to WSECC and NERC standards. The ISO may adjust the Ancillary Services standards temporarily to take into account, among other things variations in system conditions, real-time dDispatch constraints, contingencies, and voltage and dynamic stability assessments. Where practicable, the ISO will provide notice, via the ISO Home Page, of any temporary adjustments to Ancillary Service standards by 6:00 p.m. two days ahead of the Trading Day to which the adjustment will apply.

* * *

2.5.3.1 Regulation Service. The ISO shall maintain sufficient Generating Units immediately responsive to AGC in order to provide sufficient Regulation service to allow the system to meet WSECC and NERC criteria.

2.5.3.2 Spinning And Non-Spinning Reserves. The ISO shall maintain minimum contingency Operating Reserve made up of Spinning Reserve and Non-Spinning Reserve in accordance with WSECC MORC criteria equal to (a) 5% of the Demand to be met by Generation from hydroelectric resources plus 7% of the Demand to be met by Generation from other resources, or (b) the single largest Contingency, if this is greater or (c) by reference to such more stringent criteria as the ISO may determine from time to time. When the level of Operating Reserve is determined by Demand, the ISO shall not maintain Operating Reserve

with respect to Demand covered by firm purchases from outside the ISO Control Area. In addition, the ISO shall maintain Operating Reserve equal to the total amount of Interruptible Imports scheduled by Scheduling Coordinators for any hour. Such additional Operating Reserve must either be self-provided or purchased from the ISO by Scheduling Coordinators. To the extent such additional Operating Reserve is self-provided by a Scheduling Coordinator, it may consist entirely of Non-Spinning Reserve. To the extent that such additional Operating Reserve is not self-provided by a Scheduling Coordinator, the ISO will procure the necessary amounts of Operating Reserve, but not necessarily entirely from Non-Spinning Reserves.

* * *

2.5.3.4 Voltage Support.

The ISO shall determine on an hourly basis for each day the quantity and location of Voltage Support required to maintain voltage levels and reactive margins within WSECC and NERC criteria using a power flow study based on the quantity and location of scheduled Demand. The ISO shall issue daily voltage schedules, which are required to be maintained for ISO Controlled Grid reliability. All other Generating Units shall comply with the power factor requirements set forth in contractual arrangements in effect on the ISO Operations Date, or, if no such contractual arrangements exist and the Generating Unit exists within the system of a Participating TO, the power factor requirements applicable under the Participating TO's TO Tariff or other tariff on file with the FERC.

All Participating Generators shall maintain the ISO specified voltage schedule at the transmission interconnection points to the extent possible while operating within the power factor range specified in their interconnection agreements or, for Regulatory Must-Take Generation, Regulatory Must-Run Generation and Reliability Must-Run Generation consistent with existing obligations. For Generating Units, that do not operate under one of these agreements, the minimum power factor range will be within a band of 0.90 lag (producing VARs) and 0.95 lead

(absorbing VARs) power factors. Participating Generators with Generating Units existing at the ISO Operations Date that are unable to meet this operating power factor requirement may apply to the ISO for an exemption. Prior to granting such an exemption, the ISO shall require the Participating TO or UDC to whose system the relevant Generating Units are interconnected to notify it of the existing contractual requirements for ~~v~~Voltage ~~s~~Support established prior to the ISO Operations Date for such Generating Units. Such requirements may be contained in CPUC Electric Rule 21 or the Interconnection Agreement with the Participating TO or UDC. The ISO shall not grant any exemption under this Section from such existing contractual requirements. The ISO shall be entitled to instruct Participating Generators to operate their Generating Units at specified points within their power factor ranges. Generators shall receive no compensation for operating within these specified ranges.

If the ISO requires additional Voltage Support, it shall procure this either through Reliability Must-Run Contracts or, if no other more economic sources are available by instructing a Generating Unit to move its MVar output outside its mandatory range. Only if the Generating Unit must reduce its MW output in order to comply with such an instruction will it be compensated in accordance with Section 2.5.18.

All Loads directly connected to the ISO Controlled Grid shall maintain reactive flow at grid interface points within a specified power factor band of 0.97 lag to 0.99 lead. Loads shall not be compensated for the service of maintaining the power factor at required levels within the bandwidth. A UDC interconnecting with the ISO Controlled Grid at any point other than a Scheduling Point shall be subject to the same power factor requirement.

The power factor for both the Generating Units and Loads shall be measured at the interconnection point with the ISO Controlled Grid. The ISO will develop and will be authorized to levy penalties against Participating Generators, UDCs or Loads whose Voltage Support does not comply with the ISO's requirements. The ISO will establish voltage control standards with

UDCs and the operators of other Control Areas and will enter into operational agreements providing for the coordination of actions in the event of a voltage problem occurring.

Wheeling Through and Wheeling Out transactions may also be subject to a reactive charge as developed by the ISO. If the ISO shall determine that a reactive charge should be payable at a future date, it shall, subject to FERC acceptance and approval, publish annually the Voltage Support obligations and applicable charges for Wheeling Through and Wheeling Out transactions at Scheduling Points. The obligations shall be predetermined by the ISO based on the estimated amount of the Wheeling Through and Wheeling Out transactions each year.

2.5.3.5 Black Start Capability. The ISO shall determine the amount and location of Black Start Generation it requires through contingency studies that are used as the basis of the ISO's emergency plans. The studies shall specify:

(a) the initiating disturbance;

(b) the magnitude of the Outage, including the extent of the Outage (local area, ISO Controlled Grid, or W~~S~~ECC), the assumed status of Generation after the initiating disturbance, the status of interconnections, the system Demand~~load~~ level at the time of the disturbance, the interconnection support, and assumptions regarding the availability of support from other utilities to help restore Generation and Demand;

(c) the Generator performance including a percentage of Black Start units (to be determined by the ISO) which are expected to fail to start, and

(d) expected transmission system damage.

The ISO shall also specify the following load restoration performance goals:

(i) Black Start unit startup and connection times;

(ii) ISO Controlled Grid restoration times; and

(iii) load restoration times.

Scheduling Coordinators shall provide the ISO with their load restoration time requirements for any Loads that provide emergency services.

* * *

2.5.5 Time-frame For Contracting for Ancillary Services.

The ISO shall procure on a daily and hourly basis, each day, Regulation, Spinning, Non-Spinning and Replacement Reserves. The ISO shall procure Replacement Reserve on a longer-term basis pursuant to Section 2.3.5.1.3 if necessary to meet reliability criteria. The ISO Governing Board must approve all long-term Replacement Reserve contracts. The ISO shall contract for Voltage Support annually (or for such other period as the ISO may determine is economically advantageous) and on a daily or hourly basis as required to maintain sSystem rReliability. The ISO shall contract annually (or for such other period as the ISO may determine is economically advantageous) for Black Start Generation.

2.5.6 Technical Requirements for Providing Ancillary Services.

All Generating Units, System Units, Loads and System Resources providing Ancillary Services shall comply with the technical requirements set out in Sections 2.5.6.1 to 2.5.6.4 below relating to their operating capabilities, communication capabilities and metering infrastructure. No Scheduling Coordinator shall be permitted to submit a bid to the ISO for the provision of an Ancillary Service from a Generating Unit, System Unit, Load or System Resource, or to submit a sSchedule for self-provision of an Ancillary Service from that Generating Unit, System Unit, Load or System Resource, unless the Scheduling Coordinator is in possession of a current certificate issued by the ISO confirming that the Generating Unit, System Unit, Load or System Resource complies with the ISO's technical requirements for providing the Ancillary Service concerned. Scheduling Coordinators can apply for Ancillary Services certificates in accordance

with the ISO's Protocols for considering and processing such applications. The ISO shall have the right to inspect Generating Units, Loads or the individual resources comprising System Units and other equipment for the purposes of the issue of a certificate and periodically thereafter to satisfy itself that its technical requirements continue to be met. If at any time the ISO's technical requirements are not being met, the ISO may withdraw the certificate for the Generating Unit, System Unit, Load or System Resource concerned.

* * *

2.5.7.3 Market-Based Prices.

Public utilities under the FPA must submit bids for Ancillary Services capped at FERC authorized cost-based rates unless and until FERC authorizes different pricing. Public utilities under the FPA shall seek FERC Ancillary Services rate approval on bases consistent with the ISO time-frame for contracting for each Ancillary Service (hourly rate for some Ancillary Services, annual rate or otherwise for other Ancillary Services) so that cost-based bids and market-based bids for each service shall be on comparable terms. All other entities may use market-based rates not subject to any restrictions apart from those found in ~~Section 2.5.27.7 of~~ this ISO Tariff. Public utilities under the FPA which have not been approved to bid at market-based rates, will not be paid above their cost-based bid for the Ancillary Service concerned even if the relevant ~~m~~Market ~~c~~Clearing ~~p~~Price is higher.

* * *

2.5.7.4.2 Scheduling Coordinators may bid or self-provide external imports of Spinning Reserve, Non-Spinning Reserve or Replacement Reserve from resources located outside the ISO Control Area, where technically feasible and consistent with W~~S~~ECC criteria; and provided that such Scheduling Coordinators have certified to the ISO their ability to deliver the service to the point of interchange with the ISO Control Area (including with respect to their ability to make

changes, or cause such changes to be made, to interchange schedules during any interval of a Settlement Period at the discretion of the ISO).

2.5.7.4.3 Scheduling Coordinators may bid or self-provide external imports of Regulation from System Resources located outside the ISO Control Area, where technically feasible and consistent with WSECC criteria; provided that the operator of the Control Area in which the System Resources are located has entered into an agreement with the ISO for interconnected Control Area operations; and provided that such Scheduling Coordinator and the operator of the Control Area in which the resources are located have been certified by the ISO as to their ability to dynamically adjust interchange schedules based on control signals issued by the ISO anytime during a Settlement Period at the discretion of the ISO. Such certification shall include a demonstration of their ability to support the dynamic interchange of Regulation service based on ISO control signals received on dedicated communications links in accordance with ISO standards and procedures posted on the ISO Home Page.

2.5.7.4.4 Scheduling Coordinators may utilize transmission service under Existing Contracts to self-provide Regulation (consistent with the applicable ISO Protocols), from resources located outside the ISO Control Area, where technically feasible, consistent with WSECC standards

2.5.7.4.5 Scheduling Coordinators' bidding or self-provision of Ancillary Services according to this sSection 2.5.7.4 shall be consistent with the ISO Protocols.

2.5.8 The Bidding Process.

The ISO shall operate a competitive Day-Ahead and Hour-Ahead mMarket to procure Ancillary Services. It shall purchase Ancillary Services capacity at least cost to End-Use Customers consistent with maintaining sSystem rReliability. Any Scheduling Coordinator representing Generating Units, System Units, Loads or external imports of System Resources may bid into the ISO's Ancillary Services market provided that it is in possession of a current certificate for the Generating Units, System Units, external imports of System Resources or Loads concerned.

* * *

2.5.10.2 Hour-Ahead Auction. Bids for the ISO's Hour-Ahead Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve service market for each Settlement Period must be received at least two hours prior to the commencement of that Settlement Period. The bids shall include information for only the relevant Settlement Period. Failure to provide the information within the stated time frame shall result in the bids being declared invalid by the ISO. Scheduling Coordinators wishing to buy back in the Hour-Ahead Market Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity sold to the ISO in the Day-Ahead Market pursuant to ~~s~~Section 2.5.21 must do so by submitting a revised bid in the Hour-Ahead Market for the Ancillary Service and resource concerned.

* * *

2.5.12 Bid Evaluation Rules.

Bid evaluation shall be based on the following principles:

(a) the ISO shall not differentiate between bidders other than through price and capability to provide the service, and the required locational mix of services;

(b) to minimize the costs to users of the ISO Controlled Grid, the ISO shall select the bidders with lowest bids for capacity which meet its technical requirements, including location and operating capability;

(c) for the Day-Ahead Market, the Day-Ahead bids shall be evaluated independently for each of the 24 Settlement Periods of the following Trading Day;

(d) for the Hour-Ahead Market, the ISO shall evaluate bids in the two hours preceding the hour of operation;

(e) the ISO will procure sufficient Ancillary Services in the Day-~~-~~Ahead Market to meet its forecasted requirements, as known at the close of the Day-Ahead Market, except that

the ISO may elect to procure a portion of such requirements in the Hour-Ahead Markets if the ISO first provides notice to Scheduling Coordinators of such action, including the approximate hourly megawatt amounts of each Ancillary Service that it intends to procure in the Hour-Ahead Markets.

2.5.13 Evaluation of Ancillary Services Bids.

When Scheduling Coordinators bid into the Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve markets, they may bid the same capacity into as many of these markets as desired by providing the appropriate bid information to the ISO. The ISO shall evaluate bids in the markets for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve sequentially and separately in the following order: Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve. Any capacity accepted by the ISO in one of these markets shall not be passed on to another market, except that capacity accepted in the Regulation market that represents the downward range of movement accepted by the ISO may be passed on to another market; any losing bids in one market may be passed onto another market, if the Scheduling Coordinator so indicates to the ISO. A Scheduling Coordinator may specify capacity bid into only the markets it desires. A Scheduling Coordinator shall also have the ability to specify different capacity prices and different Energy prices for the Spinning Reserve, Non-Spinning Reserve, Replacement Reserve and Regulation markets. The bid information, bid evaluation and price determination rules set forth below shall be used in the Day-Ahead, Hour-Ahead and real-time procurement of Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve.

A Scheduling Coordinator providing one or more Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve services may not change the identification of the Generating Units or Loads offered in the Day-Ahead Market, the Hour-Ahead Market or in real time for such services unless specifically approved by the ISO.

2.5.14 The Regulation Auction.

Bid Information. Each Scheduling Coordinator j shall submit the following information for each Generating Unit or System Unit i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) resource identification (name and Location Code);

(c) the date for which the bid applies;

(d) maximum operating level (MW);

(e) minimum operating level (MW);

(f) ramp rate (MW/Min) $Ramp_{ijt}$;

(g) the upward and downward range of generating capacity over which Generating Unit or System Unit i from Scheduling Coordinator j is willing to provide Regulation for Settlement Period t ($Cap_{ijt}max$ (MW) where $Cap_{ijt}max \leq$ Period $_{minutes} * Ramp_{ijt.}$ Period $_{minutes}$ is established by the ISO, by giving Scheduling Coordinators twenty-four (24) hours advance notice, within a range from a minimum of 10 minutes to a maximum of 30 minutes. Bidders shall offer upward and downward range for Regulation service; and

(h) the bid price of the capacity reservation, stated separately for Regulation Up and Regulation Down ($CapRes_{ijt}$ ($/MW)).

If the bid is for the provision of Regulation from an external import of a System Resource, each Scheduling Coordinator j shall submit the following information for each System Resource i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) Scheduling Point;

(d) interchange ID code;

(e) external Control Area ID;

(f) Schedule ID (NERC ID number) and complete WSECC tag;

(g) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(h) the contract reference number, if applicable;

(i) maximum operating level (MW);

(j) minimum operating level (MW);

(k) ramp rate (MW/Min) $Ramp_{ijt}$;

(l) the upward and downward range of generating capacity over which System Resource i from Scheduling Coordinator j is willing to provide Regulation for Settlement Period t ($Cap_{ijt}max$ (MW)) where $Cap_{ijt}max \leq \text{Period}_{\text{minutes}} * Ramp_{ijt}$. $\text{Period}_{minutes}$ is established by the ISO, by giving Scheduling Coordinators twenty-four (24) hours advance notice, within a range from a minimum of 10 minutes to a maximum of 30 minutes. Bidders shall offer upward and downward range for Regulation service; and

(m) the bid price of the capacity reservation, stated separately for Regulation Up and Regulation Down ($CapRes_{ijt}$ ($/MW)).

Bid Evaluation. Based on the quantity and location of the system requirements, the ISO shall select Generating Units, System Units, and System Resources with the bids, which minimize the sum of the total bids of the Generating Units, System Units, and System Resources selected for Regulation Up or Regulation Down, subject to two constraints:

(a) the sum of the selected bid capacities must be greater than or equal to the required Regulation capacity; and

(b) each Generating Unit's, System Unit's, or System Resource's bid capacity must be less than or equal to that Generating Unit's, System Unit's, or System Resource's ramp rate times $Period_{minutes}$.

The total bid for each Generating Unit, System Unit, or System Resource is calculated by multiplying the capacity reservation bid price by the bid capacity.

Thus, subject to any locational requirements, the ISO will accept winning Regulation bids in accordance with the following criteria:

$$\underset{i,j}{Min} \sum TotalBidijt$$

Subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t \text{ and } Cap_{ijt} \leq Cap_{ijtmax}$$

Where

$TotalBid_{ijt} = CapRes_{ijt} * Cap_{ijt}$

$Requirement_t$ = Amount of upward and downward movement capacity required

Price Determination. The price payable to Scheduling Coordinators for Regulation Capacity made available for upward and downward movement in accordance with the ISO's Final Day-Ahead Schedules shall, for each Generating Unit, System Unit, and System Resource concerned, be the ~~z~~Zonal ~~m~~Market ~~c~~Clearing ~~p~~Price as follows:

$PAGC_x = MCP_{xt}$

Where:

The ~~z~~Zonal ~~m~~Market ~~c~~Clearing Price (MCP_{xt}) ~~price~~ is the highest priced winning Regulation capacity bid in Zone X based on the capacity reservation bid price, i.e.

$MCP_{xt} = Max\ (CapRes_{ijt})$ *in* ~~z~~*Zone x for Settlement Period t*

The ISO's auction does not compensate the Scheduling Coordinator for the minimum Energy output of Generating Units, System Units, or System Resources bidding to provide Regulation. Therefore, disposition of any minimum Energy associated with Regulation selected in the ISO's Ancillary Services markets is the responsibility of the Scheduling Coordinator selling the Regulation.

The price payable to Scheduling Coordinators for Regulation capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21 shall be the bid price of the Regulation Capacity reserved ($CapRes_{ijt}$ *($/MW)*).

2.5.15 The Spinning Reserve Auction.

Bid Information. If the bid is for the provision of Spinning Reserve from a Generating Unit or System Unit, each Scheduling Coordinator j must submit the following information for each Generating Unit or System Unit i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) resource identification (name and Location Code);

(c) the date for which the bid applies;

(d) maximum operating level (MW);

(e) minimum operating level (MW);

(f) ramp rate (MW/min);

(g) MW additional capability synchronized to the system, immediately responsive to system frequency, and available within 10 minutes ($Cap_{ijt}max$) for Generating Unit i, or System Unit I, from Scheduling Coordinator j, for Settlement Period t.

(h) bid price of capacity reserved ($CapRes_{ijt}$ ($/MW));

and

(i) an indication whether the capacity reserved would be available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency.

If the bid is for the provision of Spinning Reserve from an external import of a System Resource, each Scheduling Coordinator j must submit the following information for each external import of a System Resource i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) the date for which the bid applies;

(c) ramp rate if applicable (MW/Min);

(d) MW additional capability synchronized to the system, immediately responsive to system frequency and available at the point of interchange with the ISO Control Area, within 10 minutes ($Cap_{ijt}max$) of the ISO calling for the external import of System Resource i, from Scheduling Coordinator j, for Settlement Period t;

(e) bid price of capacity reserved ($CapRes_{ijt}$ ($/MW));

and

(f) an indication whether the capacity reserved would be available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency

Bid Evaluation. Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units and external imports of System Resources with the bids which minimize the sum of the total bids of the Generating Units, System Units and external imports of System Resources selected subject to two constraints:

(a) the sum of the selected bid capacities must be greater than or equal to the required Spinning Reserve capacity; and

(b) each Generating Unit's, System Unit's or external import's bid capacity must be less than or equal to that Generating Unit's, System Unit's or external import's ramp rate times 10 minutes.

The total bid for each Generating Unit, System Unit or external import of a System Resource is calculated by multiplying the capacity reservation bid price by the bid capacity. Thus, subject to any locational requirements, the ISO will select the winning Spinning Reserve bids in accordance with the following criteria:

$$Min \sum_{i,j} Totalbid_{ijt}$$

Subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

$$and\ Cap_{ijt} \leq Cap_{ijt}max$$

Where

$$TotalBid_{ijt} = Cap_{ijt} * CapRes_{ijt}$$

$Requirement_t$ = the amount of Spinning Reserve capacity required

Price Determination. The price payable to Scheduling Coordinators for Spinning Reserve Capacity made available in accordance with the ISO's Final Day-Ahead Schedules shall, for each Generating Unit or external import of a System Resource concerned be the ~~z~~Zonal ~~m~~Market ~~c~~Clearing ~~p~~Price for Spinning Reserve calculated as follows:

$Psp_{xt} = MCP_{xt}$

Where the ~~z~~Zonal ~~m~~Market ~~c~~Clearing ~~p~~Price (MCP_{xt}) for Spinning Reserve is the highest priced winning Spinning Reserve capacity bid in Zone X based on the capacity reservation bid price, i.e.:

$MCP_{xt} = Max(CapRes_{ijt})$ in ~~z~~Zone *x* for Settlement Period t

The ISO's auction does not compensate a Scheduling Coordinator for the minimum Energy output of Generating Units, System Units or System ~~r~~Resources bidding to provide Spinning Reserve. Therefore, any minimum Energy output associated with Spinning Reserve selected in the ISO's auction is the responsibility of the Scheduling Coordinator selling the Spinning Reserve.

The price payable to Scheduling Coordinators for Spinning Reserve Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21 shall be the bid price of the Spinning ~~r~~Reserve capacity reserved ($CapRes_{ijt}$($/MW)).

2.5.16 The Non-Spinning Reserve Auction.

Bid information. If the bid is for the provision of Non-Spinning Reserve from a Generating Unit or System Unit, each Scheduling Coordinator j must submit the following information for each Generating Unit or System Unit i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) Generating Unit or System Unit identification (name and Location Code);

(c) the date for which the bid applies;

(d) maximum operating level (MW);

(e) minimum operating level (MW);

(f) ramp rate (MW/Min);

(g) the MW capability available within 10 minutes ($Cap_{ijt}max$);

(h) the bid price of the capacity reserved ($CapRes_{ijt}$($/MW));

(i) time to synchronization following notification (min);

and

(j) an indication whether the capacity reserved would be available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency.

If the bid is for the provision of Non-Spinning Reserve from an external import of a System Resource, each Scheduling Coordinator j must submit the following information for each external import of a System Resource i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) the date for which the bid applies;

(c) ramp rate if applicable (MW/Min);

(d) the MW capability available at the point of interchange with the ISO Control Area, within 10 minutes ($Cap_{ijt}max$) of the ISO calling for the external import of System Resource I, from Scheduling Coordinator j, for Settlement Period t;

(e) the bid price of the capacity reserved ($CapRes_{ijt}$($/MW)); and

(f) an indication whether the capacity reserved would be available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency.

If the bid is for the provision of Non-Spinning Reserve from a Load located within the ISO Control Area, each Scheduling Coordinator j must submit the following information for each Load i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) Load identification name and Location Code;

(c) the date for which the bid applies;

(d) Demand reduction available within 10 minutes ($Cap_{ijt}max$);

(e) to interruption following notification (min);

(f) maximum allowable curtailment duration (hr);

(g) the bid price of the capacity reserved ($CapRes_{ijt}$($/MW)); and

(h) an indication whether the capacity reserved would be available for Demand reduction only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency

Bid Evaluation. Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units, Loads or external imports of System Resources with the bids which minimize the sum of the total bids of the Generating Units, System Units, Loads or external imports of System Resources selected subject to two constraints:

(a) the sum of the selected bid capacities must be greater than or equal to the required Non-Spinning Reserve capacity; and

(b) each Generating Unit's, System Unit's, Load's or external import's bid capacity must be less than or equal to that Generating Unit's, System Unit's, Load's or external import's ramp rate (or time to interruption in the case of a Load offering Demand reduction) times the difference between 10 minutes and the time to synchronize in the case of a Generating Unit or System Unit or to interruption in the case of a Load. The total bid for each Generating Unit, System Unit, Load or external import of a System Resource is calculated by multiplying the capacity reservation bid by the bid capacity.

Thus subject to any locational requirements, the ISO will accept the winning Non-Spinning Reserve bids in accordance with the following criteria:

$$Min \sum_{i,j} Totalbid_{ijt}$$

Subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

$$Cap_{ijt} \leq Cap_{ijt}max$$

Where

$TotalBid_{ijt} = Cap_{ijt} * CapRes_{ijt}$

$Requirement_t$ = the amount of Non-Spinning Reserve capacity required

Price Determination. The price payable to Scheduling Coordinators for Non-Spinning Reserve Capacity made available in accordance with the ISO's Final Day-Ahead Schedules shall for each Generating Unit, System Unit, Load or external import of a System Resource concerned be the ~~z~~Zonal ~~m~~Market ~~c~~Clearing ~~p~~Price for Non-Spinning Reserve calculated as follows:

$Pnonsp_{xt} = MCP_{xt}$

Where the ~~z~~Zonal ~~m~~Market ~~c~~Clearing ~~p~~Price (MCP_{xt}) for Non-Spinning Reserve is the highest priced winning Non-Spinning Reserve bid in Zone X based on the capacity reservation bid price, i.e.:

$MCP_{xt} = Max(CapRes_{ijt})$ in ~~z~~Zone x for Settlement Period t.

The price payable to Scheduling Coordinators for Non-Spinning Reserve Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21 shall be the bid price of the Non-Spinning Capacity reserved ($CapRes_{ijt}$(\$/MW)).

2.5.17 The Replacement Reserve Auction.

Bid Information. If the bid is for the provision of Replacement Reserve from a Generating Unit or System Unit each Scheduling Coordinator j must submit the following information for each Generating Unit or System Unit i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) Generating Unit or System Unit identification (name and Location Code);

(c) the date for which the bid applies;

(d) maximum operating level (MW);

(e) minimum operating level (MW);

(f) ramp rate (MW/Min);

(g) the MW capacity available within 60 minutes ($Cap_{ijt}max$);

(h) the bid price of the capacity reserved ($CapRes_{ijt}$ (\$/MW)); and

(i) time to synchronize following notification (min).

If the bid is for the provision of Replacement Reserve from an external import of a System Resource, each Scheduling Coordinator j must submit the following information for each external import of a System Resource i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) the date for which the bid applies;

(c) ramp rate applicable (MW/Min);

(d) the MW capability available at the point of interchange with the ISO Control Area, within 60 minutes ($Cap_{ijt}max$) of the ISO calling for the external import of System Resource i, from Scheduling Coordinator j, for Settlement Period t; and

(e) bid price of capacity reserved ($CapRes_{ijt}$;($/MW)).

If the bid is for the provision of Replacement Reserve from a Load located within the ISO Control Area, each Scheduling Coordinator j must submit the following information for each Load i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) Load identification (name and Location Code);

(c) the date for which the bid applies;

(d) the Demand reduction available within 60 minutes (Cap_{ijt} (MW));

(e) time to interruption following notification (min);

(f) maximum allowable curtailment duration (hr); and

(g) the bid price of the capacity reserved ($CapRes_{ijt}$ ($/MW)).

Bid Evaluation. Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units, Loads or external imports of System Resources with the bids which minimize the sum of the total bids of the Generating Units, System Units, Loads or external imports of System Resources selected subject to two constraints:

(a) the sum of the selected bid capacities must be greater than or equal to the required Replacement Reserve capacity; and

(b) each Generating Unit's, System Unit's, Load's or external import's bid capacity must be less than or equal to that Generating Unit's, System Unit's, Load's or external import's ramp rate (or time to interruption in the case of a Load offering Demand reduction) times the difference between 60 minutes and the time to synchronize in the case of Generating Unit or System Unit, or to interruption in the case of Load.

The total bid for each Generating Unit, System Unit, Load or external import of System Resource is calculated by multiplying the capacity reservation bid price by the bid capacity.

Thus, subject to any locational requirements, the ISO will select the winning Replacement Reserve bids in accordance with the following criteria:

$$Min \sum_{i,j} Totalbid_{ijt}$$

Subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

$$Cap_{ijt} \leq Cap_{ijt}max$$

Where

$TotalBid_{ijt} = Cap_{ijt} * CapRes_{ijt}$

$Requirement_t$ = the amount of Replacement Reserve capacity

Price Determination. The price payable to Scheduling Coordinators for Replacement Reserve Capacity made available in accordance with the ISO's Final Day-Ahead Schedules shall, for each Generating Unit, System Unit, Load or external import of a System Resource, be the zZonal mMarket cClearing pPrice for Replacement Reserve calculated as follows:

$PRepRes_{xt} = MCP_{xt}$

Where the zZonal mMarket cClearing pPrice (MCP_{xt}) for Replacement Reserve is the highest priced winning Replacement Reserve bid in Zone X based on the capacity reservation bid price, i.e.:

$MCP_{xt} = Max(CapRes_{ijt})$ in zZone *x* for Settlement Period t.

The price payable to Scheduling Coordinators for Replacement Reserve Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services schedules issued in accordance with sSection 2.5.21 shall be the bid price of the Replacement Reserve capacity reserved ($CapRes_{ijt}(\$/MW)$).

2.5.18 Voltage Support.

As of the ISO Operations Date, the ISO will contract for Voltage Support service with the owners of Reliability Must-Run Units. Payments for public utilities under the FPA shall be capped at the FERC authorized cost-based rates unless and until FERC authorizes different pricing. The ISO shall pay owners of Reliability Must-Run uUnits for long-term Voltage Support through their Scheduling Coordinators.

In addition, any Participating Generator who is producing Energy shall, upon the ISO's specific request, provide reactive energy output outside the Participating Generator's Voltage Support obligation defined in Section 2.5.3.4.

The ISO shall select Participating Generator's Generating Units which have been certified for Voltage Support to provide this additional Voltage Support. Subject to any

locational requirements, the ISO shall select the least costly Generating Units from a computerized merit order stack to back down to produce additional Voltage Support in each location where Voltage Support is needed.

The ISO shall pay to the Scheduling Coordinator for that Participating Generator the opportunity cost of reducing Energy output to enable reactive energy production. This opportunity cost shall be:

Max{0, Zonal Settlement Interval Ex Post Price - Generating Unit bid price } x reduction in Energy output (MW).

If necessary, the ISO shall develop a regulatory cost-based determination of marginal operating cost to be used in place of the Generating Unit bid price.

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2.5.20 Obligations for and Self-Provision of Ancillary Services.

2.5.20.1 Ancillary Service Obligations. Each Scheduling Coordinator shall be assigned a share of the total Regulation, Spinning Reserve, Non-Spinning and Replacement Reserve requirements by the ISO. Any references in this Tariff to the Ancillary Service "Regulation" shall be read as referring to "Regulation Up" or "Regulation Down". The share assigned to each Scheduling Coordinator is described in Section 2.5.20 and in Section 2.5.28 as that Scheduling Coordinator's obligation. Each Scheduling Coordinator's Regulation obligation in each Zone shall be pro rata based upon the same proportion as the Scheduling Coordinator's metered hourly Demand (excluding exports) bears to the total metered Demand (excluding exports) served in each hour in that Zone. Each Scheduling Coordinator's Operating Reserve obligation in each Zone shall be pro rata based upon the same proportion as the ratio of the product of its percentage obligation based on metered output and the sum of its metered Demand and firm exports bears to the total of such products for all Scheduling Coordinators in the Zone. The

Scheduling Coordinator's percentage obligation based on metered output shall be calculated as the sum of 5% of its real-time Demand (except the Demand covered by firm purchases from outside the ISO Control Area) met by Generation from hydroelectric resources plus 7% of its Demand (except the Demand covered by firm purchases from outside the ISO Control Area) met by Generation from non-hydroelectric resources in that Zone, plus 100% of any Interruptible Imports and on-demand obligations which it schedules. Each Scheduling Coordinator's Replacement Reserve obligation in each Zone is calculated as described in Section 2.5.28.4. Scheduling Coordinator obligations for each Ancillary Service will be calculated based on the requirement for each Ancillary Service as the ISO determines prior to the adjustment set forth in Section 2.5.3.6.

2.5.20.2 Right to Self-Provide.

Each Scheduling Coordinator may choose to self-provide all, or a portion, of its Regulation, Operating Reserve, and Replacement Reserve obligation in each Zone. The ISO shall schedule self-provided Ancillary Services, Day-Ahead and Hour-Ahead, and Dispatch self-provided Ancillary Services in real time. To the extent that a Scheduling Coordinator self-provides, the ISO shall correspondingly reduce the quantity of the Ancillary Services concerned, which it procures as described in Sections 2.5.14 to 2.5.17. In accordance with Section 2.5.22.11 and Section 2.5.26.2, if a Scheduling Coordinator uses capacity scheduled to self-provide Spinning Reserve, Non-Spinning Reserve, or Replacement Reserve to supply Uninstructed Imbalance Energy to the ISO from a Generating Unit, Curtailable Demand, or System Resource under circumstances that would cause the elimination of payments to the Scheduling Coordinator under Section 2.5.26.2 if the capacity had been bid and was selected by the ISO to supply the Ancillary Service, the Scheduling Coordinator shall pay to the ISO the amount of the payment that would be eliminated under that section. Scheduling Coordinators may trade Ancillary Services obligations so that any Scheduling Coordinator may reduce its Ancillary Services

obligation through purchase of Ancillary Services capacity from another Scheduling Coordinator, or self-provide in excess of its obligation to sell Ancillary Services to another Scheduling Coordinator, subject to the limits specified under Section 2.5.20.5.2. If a Scheduling Coordinator's Day-Ahead self-provided Ancillary Service sSchedule is decreased in the Hour-Ahead Market, such decrease shall be deemed to be replaced at the Market Clearing Price in the Hour-Ahead Market, pursuant to Section 2.5.21.

* * *

2.5.20.4 Services Which May Be Self-Provided. The ISO shall permit Scheduling Coordinators to self-provide the following Ancillary Services:

(a) Regulation;

(b) Spinning Reserve;

(c) Non-Spinning Reserve; and

(d) Replacement Reserve.

The ISO may from time to time add other Ancillary Services to this list as it considers appropriate.

2.5.20.5 Time Frame for Informing ISO of Self-Provision.

2.5.20.5.1 Day-Ahead Schedule. At the Day-Ahead scheduling process, Scheduling Coordinators shall be required to submit information on self-provided Ancillary Services within the time frame stated in Section 2.5.10.1. Failure to submit the required information within the stated time frame for any hour shall lead to the self-provision for that hour being declared invalid by the ISO, and under such circumstances the ISO shall purchase sufficient Ancillary Services to meet the Scheduling Coordinator's requirements to match its Day-Ahead Schedule.

* * *

2.5.20.6 Information To Be Submitted By Scheduling Coordinators For Each Service. Scheduling Coordinators electing to self-provide Ancillary Services shall submit the information for each self-provided Ancillary Service as described in Sections 2.5.14 to 2.5.17, excluding the capacity price information, but including the name of the trading Scheduling Coordinator in the case of Inter-Scheduling Coordinator Ancillary Service Trades.

2.5.20.7 Acceptance of Self-Provided Ancillary Service Schedules. The ISO will refuse to accept self-provided Ancillary Service sSchedules only to the extent that they fail to meet requirements contained in this ISO Tariff. In particular, self-provided Ancillary Service sSchedules must satisfy the following conditions:

(a) the Scheduling Coordinator has a current certificate of technical eligibility for the Generating Units, System Units, Loads or System Resources selected for the Ancillary Services in question;

(b) to the extent not provided under (a), the Generating Units, System Units, Loads and System Resources have the instrumentation, communication and metering equipment necessary to permit the ISO to dispatch the offered Ancillary Services and verify that the services have been provided;

(c) the scheduling information provided by the Scheduling Coordinator is deemed to be valid in accordance with Appendix E and the ISO Protocols; and

(d) the Generating Units, System Units, Loads or System Resources meet the ISO's locational requirements for the Ancillary Services.

2.5.21 Scheduling of Units to Provide Ancillary Services.

The ISO shall prepare supplier schedules for Ancillary Services (both self-provided and purchased by the ISO) for the Day-Ahead and the Hour-Ahead Markets. The ISO shall notify each Scheduling Coordinator no later than 1:00 p.m. of the day prior to the Trading Day of their

Ancillary Services schedules for the Day-Ahead and no later than one hour prior to the operating hour of their Ancillary Services schedules for the Hour-Ahead. The ISO Protocols set forth the information, which will be included in these schedules. Where long-term contracts are involved, the information may be treated as standing information for the duration of the contract.

If, at any time after the issuance of Final Day-Ahead Schedules for the Trading Day and before the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day, the ISO determines that it requires Ancillary Services in addition to those included in the Final Day-Ahead Schedule (in the appropriate ~~z~~Zone if procuring zonally), the ISO may procure such additional Ancillary Services by providing Scheduling Coordinators with amended supplier schedules for the Day-Ahead Markets that include Ancillary Services for which previously submitted (but not selected) bids remain available and have not previously been withdrawn. The ISO shall select such Ancillary Services in price merit order (and in the relevant ~~z~~Zone if the ISO is procuring Ancillary Services on a ~~z~~Zonal basis). Such amended supplier schedules shall be provided to the Scheduling Coordinators no later than the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day.

Once the ISO has given Scheduling Coordinators notice of the Day-Ahead and Hour-Ahead ~~s~~Schedules, these schedules represent binding commitments made in the markets between the ISO and the Scheduling Coordinators concerned, subject to any amendments issued as described above. Any minimum energy input and output associated with Regulation and Spinning Reserve services shall be the responsibility of the Scheduling Coordinator, as the ISO's auction does not compensate the Scheduling Coordinator for the minimum energy output of Generating Units bidding to provide these services. Accordingly the Scheduling Coordinators shall adjust their schedules to accommodate the minimum outputs required by the Generating Units included on the Schedules.

Notwithstanding the foregoing, a Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace that capacity in whole or in part from the ISO if the scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or if the Ancillary Service associated with a Generating Unit, Curtailable Demand, or System Resource successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduling Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replaced Ancillary Service shall be the Market Clearing Price in the Hour-Ahead Market for the Ancillary Service for the Settlement Period concerned for the Zone in which the Generating Units or other resources are located. The ISO will purchase the Ancillary Service concerned from another Scheduling Coordinator in the Hour-Ahead Market in accordance with the provisions of the ISO Tariff.

2.5.22 Rules For Real-Time Dispatch of Imbalance Energy Resources.

* * *

2.5.22.2 General Principles. The ISO shall base real-time Dispatch of Generating Units, System Units, Loads and System Resources on the following principles:

(a) the ISO shall dispatch Generating Units, System Units, and System Resources providing Regulation service to meet NERC and WECC Area Control Error (ACE) performance requirements;

(b) the ISO shall determine whether the Regulation Generating Units, System Units, and System Resources are operating at a point away from their preferred operating point and project the Imbalance Energy requirements based on the forecasted Demand for the next Dispatch Interval. The ISO shall then Dispatch Generating Units, System Units, and System Resources available (either providing Spinning Reserve, Non-

Spinning Reserve, Replacement Reserve or offering Supplemental Energy) to meet the projected Imbalance Energy requirements for the next Dispatch Interval and return the Regulation Generating Units, System Units, and System Resources to their preferred operating points to restore their full regulating margin;

(c) the ISO shall economically Dispatch Generating Units, System Units, Loads and System Resources only to meet its Imbalance Energy requirements and eliminate any Price Overlap between Energy Bids subject to resource and transmission system ~~c~~Constraints;

(d) subject to Section 2.5.22.3 and its subparts, the ISO shall select the Generating Units, System Units, Loads and System Resources to be dispatched to meet its Imbalance Energy requirements and eliminate any Price Overlap based on a constrained optimization method to minimize the overall cost of Imbalance Energy subject to resource and transmission system ~~c~~Constraints;

(e) subject to Section 2.5.22.3 and its subparts, the ISO shall not discriminate between Generating Units, System Units, Loads and System Resources other than based on price, and the effectiveness (e.g., location and ramp rate) of the resource concerned to respond to the fluctuation in Demand or Generation;

(f) Generating Units, System Units, Loads and System Resources shall be dispatched during the operating hour only until the next variation in Demand or the end of the operating hour, whichever is sooner. In dispatching such resources, the ISO makes no further commitment as to the duration of their operation, nor the level of their output or Demand, except to the extent that a Dispatch instruction causes Energy to be delivered in a different Dispatch Interval.

2.5.22.3 Ancillary Services Dispatch. The ISO may Dispatch Generating Units, Loads, System Units and System Resources contracted to provide Ancillary Services (either procured

through the ISO's competitive market, or self-provided by Scheduling Coordinators) to supply Imbalance Energy. During normal operating conditions, the ISO shall Dispatch the following resources to supply Imbalance Energy: (i) those Generating Units, Loads, System Units and System Resources having offered Supplemental Energy bids, (ii) those Generating Units, Loads, System Units and System Resources contracted to provide Replacement Reserve and (iii) those Generating Units, Loads, System Units and System Resources that have contracted to provide Spinning and Non-Spinning Reserve, except for those resources that have indicated that the capacity reserved would be available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency. In the event of an unplanned Outage, a Contingency or a threatened or actual System Emergency, the ISO may also Dispatch all other Generating Units, Loads, System Units and System Resources contracted to provide Spinning Reserve or Non-Spinning Reserve to supply Imbalance Energy. If a Generating Unit, Load, System Unit or System Resource, which is supplying Operating Reserve, is Dispatched to provide Imbalance Energy, the ISO shall replace the Operating Reserve from the same or another resource within the time frame specified in the WSECC guidelines.

* * *

2.5.22.3.2 Dispatch of Self-Provided Ancillary Services. Where a Scheduling Coordinator has chosen to self-provide the whole of the additional Operating Reserve required to cover any Interruptible Imports which it has scheduled and has identified specific Generating Units, Loads, System Units or System Resources as the providers of the additional Operating Reserve concerned, the ISO shall Dispatch only the designated Generating Units, Loads, System Units or System Resources in the event of the ISO being notified that the Interruptible Import is being curtailed. For all other Ancillary Services which are being self-provided the

Energy Bid shall be used to determine the Dispatch, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 2.5.22.3.

2.5.22.4 Supplemental Energy Bids. In addition to the Generating Units, Loads and System Resources which have been scheduled to provide Ancillary Services in the Day-Ahead and Hour-Ahead ~~m~~Markets, the ISO may Dispatch Generating Units, Loads or System Resources for which Scheduling Coordinators have submitted Supplemental Energy bids.

* * *

2.5.22.6 Real-Time Dispatch. The ISO shall economically Dispatch each Generating Unit, Curtailable Demand~~Load~~, System Unit or System Resource that is effective to meet Imbalance Energy requirements and eliminate any Price Overlap in real time, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 2.5.22.3. The ISO shall determine that additional output is needed if the current output levels of the Regulation Generating Units, System Units, and System Resources deviate from their preferred operating points by more than a specified threshold (to be determined by the ISO), or to meet the projected Imbalance Energy requirements for the next Dispatch Interval. The ISO shall employ a multi-interval constrained optimization methodology (RTD Software) to calculate an optimal dispatch for each Dispatch Interval within a time horizon that shall extend to the end of the next hour. The ISO shall Dispatch resources that have submitted Energy Bids over the time horizon to meet forecasted Imbalance Energy requirements minimizing the Imbalance Energy procurement cost over the entire time horizon, subject to resource and transmission system constraints. However, Dispatch Instructions shall be issued for the next Dispatch Interval only. The ISO also shall instruct resources to start up or shut down over the time horizon based on their submitted and validated Start-Up Fuel Costs, Minimum Load Costs and Energy Bids. These resources shall receive binding start-up or shut-down pre-dispatch instructions as required by their startup time. The ISO shall only start resources that can start

within the time horizon. The ISO may shut down resources that do not need to be on-line if constraints within the time horizon permit. However, resources providing Regulation or Spinning Reserve shall not be shut down. On-line resources providing Non-Spinning or Replacement Reserve shall also not be eligible for shutdown, unless their minimum down time does not exceed 10 minutes.

* * *

2.5.22.6.2 Transmission System Constraints.

RTD shall use a ~~z~~Zonal DC network model where all nodes within a ~~z~~Zone would be collapsed into a single equivalent "~~z~~Zonal bus." The constraints using the ~~z~~Zonal network model shall be the following:

a) Power balance constraint in each ~~z~~Zone. The system Imbalance Energy requirement shall be calculated on a ~~z~~Zonal basis. The power balance constraints shall dictate an optimal ~~d~~Dispatch that would eliminate the Imbalance Energy requirement in all ~~z~~Zones, subject to (b) below.

b) Inter-Zonal Interface constraints. These constraints shall limit the net active power flow on Inter-Zonal Interfaces at or below their transfer limits. For Inter-Zonal Interfaces between the ISO Control Area and another ~~c~~Control ~~a~~Area, inter-~~z~~Zonal transfer capacity shall be reserved for awarded Ancillary Services from System Resources not already Dispatched.

2.5.22.6.3 Inter-hour Dispatch of Resources Without Real-Time Energy Bids.

Real-~~T~~time Dispatch Instructions shall be issued for each Dispatch Interval as needed to prescribe the ramp between a resource's Final Hour-Ahead Schedule in one hour to its Final Hour-Ahead Schedule in the immediately succeeding operating hour. Such Dispatch Instructions shall be based on the lesser of: 1) the applicable operational ramp rate as provided for in SBP Section 6.5 and 2) the ramp rate associated with the Standard Ramp. The Dispatch

Instructions for ramping of Generating Units without ~~R~~real-~~T~~time Energy Bids in both operating hours shall begin 10 minutes prior to the start of each operating hour and shall end no sooner than 10 minutes after and no later than 50 minutes after the start of each operating hour. Energy resulting from the Standard Ramp shall be deemed Standard Ramping Energy and will be settled in accordance with SABP Appendix D-1 Section 2.1.2. Energy resulting from any ramp extending beyond the Standard Ramp will be deemed Ramping Energy Deviation and will be settled in accordance with SABP Appendix D-1 Section 2.1.2.

2.5.22.6.4 Inter-hour Dispatch of Resources With Real-Time Energy Bids.

Real-~~T~~time Dispatch Instructions associated with the ramp between a resource's Final Hour-Ahead Schedule in one hour to its Final Hour-Ahead Schedule in the immediately succeeding operating hour shall be determined optimally by the RTD Software if the ISO has bids for either or both relevant operating hours. For any operating hour(s) for which bids have been submitted Dispatch Instructions will be optimized such that the Dispatch Operating Point is within the bid range(s). For any operating hour without submitted bids Dispatch Instructions will be optimized such that the Dispatch Operating Point conforms to the schedule within the operating hour. Energy resulting from the Standard Ramp shall be deemed Standard Ramping Energy and will be settled in accordance with SABP Appendix D Section 2.1.2. Energy resulting from any ramp extending beyond the Standard Ramp will be deemed Ramping Energy Deviation and will be settled in accordance with SABP Appendix D Section 2.1.2. Energy delivered or consumed as a result of ISO Dispatch of a resource's Energy Bid in one operating hour to a Dispatch Operating Point such that the resource cannot return to its successive operating hour Final Hour-Ahead Schedule by the beginning of the next operating hour is Residual Energy and shall be settled as Instructed Imbalance Energy as provided for in SABP Appendix D Section 2.1.2 and also may be eligible for recovery of its applicable Energy Bid costs in accordance with Section 11.2.4.1.1.1. Similarly, Energy delivered or consumed as a result of ISO Dispatch of a

resource's Energy Bid in a future operating hour to a Dispatch Operating Point different from its current operating hour Final Hour-Ahead Schedule prior to the end of the current operating hour is also considered Residual Energy and shall be settled as Instructed Imbalance Energy as provided for in SABP Appendix D Section 2.1.2 and also may be eligible for recovery of its applicable Energy Bid costs in accordance with Section 11.2.4.1.1.1. When Ramping Energy Deviation and Residual Energy coexist within a given Dispatch Interval, the Ramping Energy Deviation shall be the portion of Instructed Imbalance Energy that is produced or consumed within the schedule-change band defined by the Final Hour-Ahead Schedules of the two consecutive Settlement Periods; the Residual Energy shall be the portion of Instructed Imbalance Energy that is produced or consumed outside the schedule-change band.

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2.5.22.11 Failure to Conform to Dispatch Instructions. All Scheduling Coordinators, Participating Generators, owners or operators of Curtailable Demands and operators of System Resources providing Ancillary Services (whether self-provided or procured by the ISO) or whose Supplemental Energy bids have been accepted by the ISO shall be obligated to respond or to secure response to the ISO's Dispatch Instructions in accordance with their terms, and to be available and capable of doing so, for the full duration of the Settlement Period. Dispatch Instructions will be deemed delivered and associated Energy will be settled as Instructed Imbalance Energy in accordance with Section 11.2.4.1.1. If a Generating Unit, Curtailable Demand or System Resource is unavailable or incapable of responding to a Dispatch Instruction, or fails to respond to a Dispatch Instruction in accordance with its terms, the Generating Unit, Curtailable Demand or System Resource:

(a) shall be declared and labeled as non-conforming to the ISO's instructions unless it has notified the ISO of an event that prevents it from performing its obligations within 30 minutes of the onset of such event through a SLIC log entry. Notification of non-

compliance via the Automated Dispatch System (ADS) will not supplant nor serve as the offical notification mechanism to the ISO;

(b) cannot set the Dispatch Interval Ex Post Price pursuant to Section 2.5.23.2.1.2; and

(c) the Scheduling Coordinator for the Participating Generator, owner or operator of the Curtailable Demand or System Resource concerned shall have Uninstructed Imbalance Energy due to the difference between the Generating Unit's, Curtailable Demand's or System Resource's instructed and actual output (or Demand). The Uninstructed Imbalance Energy shall be subject to the settlement for Uninstructed Imbalance Energy in accordance with Section 11.2.4.1 and the Uninstructed Deviation Penalty in accordance with Section 11.2.4.1.2. This applies whether the Ancillary Services concerned are contracted or self-provided.

The ISO will develop additional mechanisms to deter Generating Units, Curtailable Demand and System Resources from failing to perform according to Dispatch instructions, for example reduction in payments to Scheduling Coordinators, or suspension of the Scheduling Coordinator's Ancillary Services certificate for the Generating Unit, Curtailable Demand or System Resource concerned.

* * *

2.5.23.1 General Principles. Instructed and Uninstructed Imbalance Energy shall be paid or charged the applicable Resource-Specific Settlement Interval Ex Post Price or the Zonal Settlement Interval Ex Post Price. These prices are determined using the Dispatch Interval Ex Post Prices. The Dispatch Interval Ex Post Prices shall be based on the bid of the marginal Generating Units, System Units, and Curtailable Demand dispatched by the ISO to increase or reduce Demand or Energy output in each Dispatch Interval as provided in Section 2.5.23.2.1.

The marginal bid is the highest bid that is accepted by the ISO's RTD Software for increased energy sSupply or the lowest bid that is accepted by the ISO's RTD Software for reduced energy sSupply. In the event the lowest price decremental bid accepted by the ISO is greater and not equal to the highest priced incremental bid accepted, then the Dispatch Interval Ex-Post Price shall be equal to the highest incremental bid accepted when there is a non-negative Imbalance Energy system requirement and equal to the lowest accepted decremental bid when there is a negative Imbalance Energy requirement.

When an Inter-Zonal Interface is operated at the capacity of the interface (whether due to scheduled uses of the interface, or decreases in the capacity of the interface), the marginal incremental or decremental bid prices in some Zones may differ from one another. In such cases, the ISO will determine separate Ex Post Prices for the Zones.

The ISO will respond to the Dispatch iInstructions issued by the RTD Software to the extent practical in the time available and acting in accordance with Good Utility Practice. The ISO will record the reasons for any variation from the Dispatch iInstructions issued by the RTD Software.

* * *

2.5.23.2.2 Hourly Ex Post Price. The Hourly Ex Post Price in a Settlement Period in each Zone will equal the absolute-value Energy-weighted average of the Dispatch Interval Ex Post Prices in each Zone, where the weights are the system total Instructed Imbalance eEnergy, except Regulation Energy, for the Dispatch Interval.

If the ISO declares a System Emergency, e.g. during times of supply scarcity, and involuntary lLoad sShedding occurs during the real-time Dispatch, the ISO shall set the Hourly Ex Post Price at the Administrative Price.

2.5.23.2.3 Price for Uninstructed Deviations for Participating Intermittent Resources.

Deviations associated with each Participating Intermittent Resource in a Scheduling Coordinator's ~~z~~Zonal portfolio shall be settled as provided in Section 11.2.4.5.1 at the monthly weighted average Dispatch Interval Ex Post Price, where the weights are the quantities of Instructed Imbalance Energy associated with each Dispatch Interval Ex Post Price.

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2.5.23.3.3 Requirement of Must-Offer Generators to File Heat Rate and Emissions Rate Data

Must-Offer Generators, as defined in Section 5.11 of this ISO Tariff, that own or control gas-fired Generating Units must file with the ISO and the FERC, on a confidential basis, the heat rates and emissions rates for each gas-fired Generating Unit that they own or control. Heat rate and emissions rate data shall be provided in the format specified by the ISO as posted on the ISO Home Page. Heat rate data provided to comply with this requirement shall not include start-up or minimum ~~l~~Load fuel costs. Must-Offer Generators must also file periodic updates of this data upon the direction of either FERC or the ISO. The ISO will treat the information provided to the ISO in accordance with this Section 2.5.23.3.3 as confidential and will apply the procedures in Section 20.3.4 of this ISO Tariff with regard to requests for disclosure of such information.

* * *

2.5.23.3.6.6 Submission of Emissions Cost Invoices

Scheduling Coordinators for Must-Offer Generators that incur Emissions Costs as a direct result of an ISO Dispatch instruction may submit to the ISO an invoice in the form specified on the ISO Home Page (the "Emissions Cost Invoice") for the recovery of such Emissions Costs. Emissions Cost Invoices shall not include any Emissions Costs specified in an RMR Contract for a unit owned or controlled by a Must-Offer Generator. All Emissions Cost Invoices must include a copy of all final invoice statements from air quality districts demonstrating the Emissions Costs incurred by the applicable ~~g~~Generating ~~u~~Unit, and such other information as the ISO may

reasonably require to verify the Emissions Costs incurred as a direct result of an ISO Dispatch instruction.

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2.5.24 Verification of Performance of Ancillary Services.

Availability of both contracted and self-provided Ancillary Services shall be verified by the ISO by unannounced testing of Generating Units, Loads and System Resources, by auditing of response to ISO Dispatch instructions, and by analysis of the appropriate Meter Data, or interchange schedules. Participating Generators, owners or operators of Loads, operators of System Units or System Resources and Scheduling Coordinators shall notify the ISO immediately whenever they become aware that an Ancillary Service is not available in any way. All Participating Generators, owners or operators of Loads and operators of System Units or System Resources shall check, monitor and/or test their system and related equipment routinely to assure availability of the committed Ancillary Services. These requirements apply whether the Ancillary Services are contracted or self-provided. For a duration specified by the ISO, the ISO may suspend the technical eligibility certificate of a Scheduling Coordinator for a Generating Unit, System Unit, Load or System Resource, which repeatedly fails to perform. The ISO shall develop measures to discourage repeated non-performance on the part of both bidders and self-providers.

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2.5.25.2 Spinning Reserve. The ISO shall test the Spinning Reserve capability of a Generating Unit, System Unit or System Resource by issuing unannounced Dispatch instructions requiring the Generating Unit-, System Unit or System Resource to ramp up to its ten minute capability. The ISO shall measure the response of the Generating Unit, System Unit or System Resource to determine compliance with requirements. The Scheduling Coordinator

for the Generating Unit, System Unit or System Resource shall be paid the Energy Bid price of the Generating Unit or System Unit for the output under the Spinning Reserve test.

* * *

2.5.26.1 Penalties for Failure to Pass Tests. A Generating Unit, Curtailable Demand, System Unit or System Resource that fails an availability test, as determined under criteria to be established by the ISO, shall be deemed not to have been available to provide the Ancillary Service concerned or the relevant portion of that Service for the entire period the Generating Unit, Curtailable Demand, System Unit or System Resource was committed to provide the Service, unless appropriate documentation (i.e., daily test records) confirming the availability of that service during the committed period(s) is presented to the ISO. The "committed period" is defined as the total of all the hours/days the Generating Unit, Curtailable Demand, System Unit or System Resource was scheduled by the ISO to provide the Ancillary Service beginning from: (i) the last successful availability test; or (ii) the last time the Generating Unit, Curtailable Demand, System Unit or System Resource actually provided Energy or reduced Demand as part of the Ancillary Service; whichever results in a shorter committed period. The Scheduling Coordinator for a Generating Unit, Curtailable Demand, System Unit or System Resource that fails an availability test shall not be entitled to payment for the Ancillary Service concerned for the committed period and adjustments to reflect this shall be made in the calculation of payments to the Scheduling Coordinator, provided that any such penalty shall be reduced to reflect any adjustment made over the duration of the committed period under Section 2.5.26.2 or 2.5.26.3.

System Units engaged in self-provision of Ancillary Services, or providing Ancillary Services to the ISO are subject to the same testing, compensation, and penalties as are applied to individual Generating Units engaged in self-provision or provision of Ancillary Services. To

perform testing, the ISO will bias the MSS's MSRE to test the responsiveness of the System Unit.

If payments for capacity for a particular Ancillary Service in a particular Settlement Period would be rescinded under more than one provision of this Section 2.5.26, the total amount to be rescinded for a particular Ancillary Service in a particular Settlement Period shall not exceed the total payment due in that Settlement Period.

* * *

2.5.26.2.3 The ISO shall calculate the real-time ability of each Generating Unit and System Unit to deliver Energy from Ancillary Services capacity awarded or self-provided for each Settlement Interval based on its operational ramp rate as described in SBP Section 6.5, maximum operating capability, and actual telemetered output. If the Generating Unit or System Unit cannot deliver the full amount of Energy from the awarded or self-provided Spinning, Non-Spinning or Replacement ~~r~~Reserve for a Settlement Interval then Ancillary Services capacity payments for the amount of Energy that cannot be delivered for the particular Settlement Interval shall be rescinded.

* * *

2.5.26.2.6 For each Settlement Interval in which a Generating Unit, Curtailable Demand, System Unit or System Resource fails to actually supply Energy from Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity in accordance with a Dispatch ~~i~~Instruction, or supplies only a portion of the Energy specified in the Dispatch Instruction, the capacity payment will be pro-rated to reflect the unavailability in that Settlement Interval of the difference between (1) the total MW of the particular Ancillary Service scheduled in that Settlement Period and (2) the amount of Energy, if any, supplied in response to the Dispatch Instruction in that Settlement Interval.

2.5.26.3 Rescission of Payments When Dispatch Instruction is Not Followed

If the total metered output of a Generating Unit, Curtailable Demand, System Unit or System Resource is insufficient to supply the amount of Instructed Imbalance Energy associated with a Dispatch Instruction issued in accordance with a bid on Spinning Reserve, Non-Spinning Reserve, or Replacement Reserve in any Settlement Interval, then the capacity payment associated with the difference between the total scheduled amount of each Ancillary Service for which Insufficient Energy was delivered, and the actual output attributed to the response to the Dispatch Instruction on each Ancillary Service, shall be rescinded. However, no capacity payment shall be rescinded if the shortfall in the metered output of the Generating Unit, Curtailable Demand, System Unit, or System Resource is less than a deadband amount published by ISO on the ISO Home Page at least twenty-four hours prior to the Settlement Interval. For any Settlement Interval with respect to which no deadband amount has been published by the ISO, the deadband amount shall be zero MWH. If the Generating Unit, Curtailable Demand, System Unit or System Resource is scheduled to provide more than one Ancillary Service in the Settlement Period, then the actual output will be attributed first to Replacement Reserve, then to Non-Spinning Reserve, and finally to Spinning Reserve, and the capacity payments associated with the balance of each Ancillary Service shall be rescinded. If the same Ancillary Service is scheduled in both the Day-Ahead and Hour-Ahead Markets, then payments shall be rescinded in proportion to the amount of each Ancillary Service scheduled in each market.

* * *

2.5.26.5 If the ISO determines that non-compliance of a Load, Generating Unit, System Unit or System Resource, with an operating order or Dispatch Instruction from the ISO, or with any other applicable technical standard under the ISO Tariff, causes or exacerbates system conditions for which the WSECC imposes a penalty on the ISO, then the Scheduling

Coordinator of such Load, Generating Unit, System Unit or System Resource shall be assigned that portion of the WSECC penalty which the ISO reasonably determines is attributable to such non-compliance, in addition to any other penalties or sanctions applicable under the ISO Tariff.

* * *

2.5.27 Settlements For Contracted Ancillary Services.

Based on the prices and quantities determined in accordance with this Section, the ISO shall operate a daily Settlement function for Ancillary Services it contracts for with Scheduling Coordinators.

The ISO shall calculate imbalances between scheduled, instructed and actual quantities of Energy provided based upon Meter Data obtained pursuant to Section 10. Schedules between Control Areas shall be deemed as being delivered in accordance with Good Utility Practice. The difference between actual and scheduled interchange shall then be addressed in accordance with the WSECC and NERC inadvertent interchange practices and procedures. Following this practice, all dynamic schedules for Ancillary Services provided to the ISO by other Control Areas shall be deemed delivered to the ISO. The difference between the Energy requested by the ISO and that actually delivered by the other Control Area shall then be accounted for and addressed through the WSECC and NERC inadvertent interchange practices and procedures.

Separate payments shall be calculated for each Settlement Period t for each Generating Unit, System Unit, System Resource and Curtailable Demand. The ISO shall then calculate a total daily payment for each Scheduling Coordinator for all the Generating Units, System Units, System Resources and Curtailable Demands that it represents for each Settlement Period t.

The settlements for the Hour-Ahead ~~m~~Markets shall be calculated by substituting Hour-Ahead prices in the relevant formulae and deducting any amounts due to the ISO from

Scheduling Coordinators who buy back in the Hour-Ahead Market Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity they sold to the ISO in the Day-Ahead Market.

2.5.27.1 Regulation.

Regulation Up and Regulation Down payments shall be calculated separately.

Quantities. The following quantity definitions shall be used for each Scheduling Coordinator in the settlement process:

$AGCUpQDA_{xt}$ = the Scheduling Coordinator's total quantity of Regulation Up capacity in Zone X sold through the ISO auction ~~at bids at or below the level specified in Section 2.5.27.7~~, and scheduled Day-Ahead j for Settlement Period t.

$AGCDownQDA_{xt}$ = the Scheduling Coordinator's total quantity of Regulation Down capacity in Zone X sold through the ISO auction ~~at bids at or below the level specified in Section 2.5.27.7~~, and scheduled Day-Ahead j for Settlement Period t.

$EnQInst_{xt}$ = Instructed Imbalance Energy increase or decrease in Zone X in real-time Dispatch for each Dispatch Interval b of Settlement Period t, determined in accordance with the ISO Protocols.

Prices. The prices in the Settlement process for Regulation Up and Regulation Down shall be those determined in Section 2.5.14 ~~for bids at or below the level specified in Section 2.5.27.7 and prices determined in accordance with Section 2.5.27.7 for bids above that level.~~

Adjustment: penalty described in Section 2.5.26.1.

$PAGCUpDA_{xt}$ = the ~~m~~Market ~~c~~Clearing ~~p~~Price, PAGC, in Zone X for Regulation Up capacity in the Day-Ahead ~~m~~Market for Settlement Period t.

$PAGCDownDA_{xt}$ = the ~~m~~Market ~~c~~Clearing ~~p~~Price, PAGC, in Zone X for Regulation Down capacity in the Day-Ahead ~~m~~Market for Settlement Period t.

Payments. Scheduling Coordinators for Generating Units providing Regulation Up capacity through the ISO auction shall receive the following payments for Regulation Up:

$$AGCUpPay_{xt} = AGCUpQDA_{xt} * PAGCUpDA_{xt} - Adjustment$$

Scheduling Coordinators for Generating Units providing Regulation Down capacity through the ISO auction shall receive the following payments for Regulation Down:

$$AGCDownPay_{xt} = AGCDownQDA_{xt} * PAGCDownDA_{xt} - Adjustment$$

Scheduling Coordinators for Generating Units shall receive the following payment for Energy output from Regulation in accordance with the settlement for Instructed Imbalance Energy under Section 11.2.4.1:

$$\sum_i [(EnQInst_{ixt} * Zonal\ Settlement\ IntervalExPostPriceinZoneX) + REPAi_{xt}]$$

$REPA_{ixt}$ = the Regulation Energy Payment Adjustment for Generating Unit i in Zone X for Settlement Period t calculated as follows:

$$[(R_{UPixt} * C_{UP}) + (R_{DNixt} * C_{DN})] * \max(\$20/MWh, P_{xt})$$

Where

R_{UPixt} = the upward range of generating capacity for the provision of Regulation from Generating Unit i in Zone X included in the bid accepted by the ISO for Generating Unit i for Settlement Period t, weighted in proportion to the ISO's need for upward Regulation. The weighting factors will be specified within a range from 0-100 percent.

The weighting factors will be set at the discretion of the ISO based on system conditions, and will be set at a level that will provide sufficient incentive to the market to supply upward Regulation for the ISO's purposes of satisfying WSECC criteria and NERC control performance standards. The ISO shall post the weighting factors consistent with the ISO Weighting Procedure, posted on the ISO website.

R_{DNixt} = the downward range of generating capacity for the provision of Regulation for Generating Unit i in Zone X included in the bid accepted by the ISO for Generating Unit i for Settlement Period t, weighted in proportion to the ISO's need for downward Regulation. The weighting factors will be specified within a range from 0-100 percent. The weighting factors will be set at the discretion of the ISO based on system conditions, and will be set at a level that will provide sufficient incentive to the market to supply downward Regulation for the ISO's purposes of satisfying WSECC criteria and NERC control performance standards. The ISO shall post the weighting factors consistent with the ISO Weighting Procedure, posted on the ISO website.

C_{UP} = 0 to 1

C_{DN} = 0 to 1

P_{xt} = the Hourly Ex Post Price for Zone X in Settlement Period t.

The ISO may modify the value of the constants C_{UP} or C_{DN} within a range of 0-1 either generally in regard to all hours or specifically in regard to particular times of the day, after the ISO Governing Board approves such modification, by a notice issued by the Chief Executive Officer of the ISO and posted on the ISO Internet "Home Page," at http//www.caiso.com, or such other Internet address as the ISO may publish from time to time, specifying the date and time from

which the modification shall take effect, which shall be not less than seven (7) days after the Notice is issued.

REPA shall not be payable unless the Generating Unit is available and capable of being controlled and monitored by the ISO Energy Management System over the full range of its Scheduled Regulation capacity for the entire Settlement Period at least the ramp rates (increase and decrease in MW/minute) stated in its bid. In addition, the total Energy available (R_{UP} plus R_{DN}) may be adjusted to be only R_{UP} or only R_{DN}, a percentage of R_{UP} or R_{DN}, or the sum of R_{UP} and R_{DN}, depending on the needs of the ISO for each direction of Regulation service.

2.5.27.2 Spinning Reserve.

Quantities. The following quantity definitions shall be used for each Scheduling Coordinator in the Settlement process:

$SpinQDA_{xt}$ = the Scheduling Coordinator's total quantity of Spinning Reserve capacity in Zone X sold through the ISO auction ~~at bids at or below the level specified in Section 2.5.27.7~~, and scheduled Day-Ahead for Settlement Period t.

$EnQInst_{xt}$ = Instructed Imbalance Energy output in Zone X in real-time Dispatch for Settlement Period t, supplied in accordance with the ISO ~~p~~Protocols.

Prices. The prices in the Settlement process for Spinning Reserve shall be those determined in Section 2.5.15 ~~for bids at or below the level specified in Section 2.5.27.7 and prices determined in accordance with Section 2.5.27.7 for bids above that level~~.

Adjustment = penalty described in Section 2.5.26.1, or rescinded capacity payments described in Section 2.5.26.2 or 2.5.26.3.

$PspDA_{xt}$ = ~~m~~Market ~~c~~Clearing ~~p~~Price, Psp, in Zone X for Spinning Reserve capacity in the Day-Ahead Market for Settlement Period t.

Payments. Scheduling Coordinators for Generating Units, System Units, or System Resources providing Spinning Reserve capacity through the ISO auction shall receive the following payments for Spinning Reserve capacity:

$SpinPay_{xt} = SpinQDA_{xt} * PspDA_{xt-Adjustment}$

Scheduling Coordinators for Generating Units, System Units, or System Resources shall receive the following payments for Energy output from Spinning Reserve capacity:

$EnQInst_{xt} * Resource\text{-}Specific\ Settlement\ Interval\ Ex\ Post\ Price_{xt}$

2.5.27.3 Non-Spinning Reserve.

Quantities. The following quantity definitions shall be used for each Scheduling Coordinator in the sSettlement process:

$NonSpinQDA_{xt}$ = the Scheduling Coordinator's total Quantity of Non-Spinning Reserve capacity in Zone X sold through the ISO's auction ~~at bids at or below the level specified in Section 2.5.27.7~~, and scheduled Day-Ahead for Settlement Period t.

$EnQInst_{xt}$ = Instructed Imbalance Energy output or Demand reduction in Zone X in real-time Dispatch for Settlement Period t, supplied in accordance with the ISO pProtocols.

Prices. The prices in the Settlement process for Non-Spinning Reserve shall be those determined in Section 2.5.16 ~~for bids at or below the level specified in Section 2.5.27.7 and prices determined in accordance with Section 2.5.27.7 for bids above that level~~.

Adjustment = penalty described in sSection 2.5.26.1, or rescinded capacity payments described in Section 2.5.26.2 or 2.5.26.3.

$PnonspDA_{xt}$ = ~~m~~Market cClearing pPrice, Pnonsp, in Zone X for Non-Spinning Reserve capacity in the Day-Ahead Market for Settlement Period t.

Payments. Scheduling Coordinators for Generating Units, System Units, System Resources, or Loads supplying Non-Spinning Reserve capacity through the ISO auction shall be paid the following for the Non-Spinning Reserve capacity:

$NonspPay_{xt} = NonSpinQDA_{xt} * PnonspDAxt - Adjustment$

Scheduling Coordinators for Generating Units, System Units, System Resources or Loads shall receive the following payments for Energy output from Non-Spinning Reserve capacity:

$EnQInst_{xt} * Resource\text{-}Specific\ Settlement\ Interval\ Ex\ Post\ Price_{xt}$

2.5.27.4 Replacement Reserve.

Quantities. The following quantity definitions shall be used for each Scheduling Coordinator in the ~~s~~Settlement process:

$RepResQDA_{xt}$ = the Scheduling Coordinator's total quantity of Replacement Reserve capacity in Zone X sold through the ISO auction ~~at bids at or below the level specified in Section 2.5.27.7~~, scheduled Day-Ahead for Settlement Period t, and from which Energy has not been generated.

$EnQInst_{xt}$ = Instructed Imbalance Energy output or Demand reduction in Zone X in real-time Dispatch for Settlement Period t, suppplied in accordance with the ISO ~~p~~Protocols.

Prices. The prices in the ~~s~~Settlement process for Replacement Reserve shall be those determined in ~~s~~Section 2.5.17 ~~for bids at or below the level specified in Section 2.5.27.7 and prices determined in accordance with Section 2.5.27.7 for bids above that level~~.

Adjustment = penalty described in ~~s~~Section 2.5.26.1, or rescinded capacity payments described in Section 2.5.26.2 or 2.5.26.3.

$PRepResDA_{xt}$ = ~~m~~Market ~~c~~Clearing ~~p~~Price, PRepRes, in Zone X for Replacement Reserve capacity in the Day-Ahead Market for Settlement Period t.

Payments. Scheduling Coordinators for Generating Units, System Units, System Resources, or Loads providing Replacement Reserve capacity through the ISO auction shall receive the following payments for the portion of a Scheduling Coordinator's Replacement Reserve capacity from which Energy has not been generated:

$RepResPay_{ijt} = (RepResQDA_{xt} -) * PRepResDA_{xt\text{-}Adjustment}$

Scheduling Coordinators shall not receive capacity payments for the portion of a Scheduling Coordinator's Replacement Reserve capacity from which Energy has been generated. The payments for Energy output from Replacement Reserve capacity are calculated as follows:

$EnQInst_{ijt} * Resource\text{-}Specific\ Settlement\ Interval\ Ex\ Post\ Price_{xt}$

2.5.27.5 Voltage Support. The total payments for each Scheduling Coordinator shall be the sum of the short-term procurement payments, based on opportunity cost, as described in Section 2.5.18, and the payments under long-term contracts.

2.5.27.6 Black Start.

Quantities. The following quantities shall be used in the Settlement process:

$EnQBS_{ijt}$ = Energy output from Black Start made by Generating Unit i from Scheduling Coordinator j (or Black Start Generator j, as the case may be) for Settlement Period t, pursuant to the ISO's order to produce.

Prices. The prices used in the Settlement process are those described in the contracts referred to in sSection 2.5.19.

Adjustment = penalty described in sSection 2.5.26.1.

Payments.

Scheduling Coordinators for owners of Reliability Must-Run Units (or Black Start Generators, as the case may be) shall receive the following payments for Energy output from Black Start facilities:

$BSEN_{ijt}=(EnQBS_{ijt}*EnBid_{ijt})+BSSUP_{ijt}-Adjustment$

where BSSUPijt is the start-up payment for a Black Start successfully made by Generating Unit i of Scheduling Coordinator j (or Black Start Generator j) in Trading Interval t calculated in accordance with the applicable Reliability Must-Run Contract (or the Interim Black Start ~~a~~Agreement as the case may be).

* * *

2.5.28 Settlement for User Charges for Ancillary Services.

(a) The ISO shall determine a separate hourly user rate for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve for each Settlement Period purchased in the Day-Ahead ~~m~~Market, and in the Hour-Ahead Market. Each rate will be charged to Scheduling Coordinators on a volumetric basis applied to each Scheduling Coordinator's obligation for the Ancillary Service concerned which it has not self-provided, as adjusted by any Inter-Scheduling Coordinator Ancillary Service Trades.

Each Scheduling Coordinator's obligation for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve for each Zone shall be calculated in accordance with Section 2.5.20.1, notwithstanding any adjustment to the quantities of each Ancillary Service purchased by the ISO in accordance with Section 2.5.3.6.

The cost of Voltage Support and Black Start shall be allocated to Scheduling Coordinators as described in Sections 2.5.28.5 and 2.5.28.6.

Quantities and rates for the Hour-Ahead ~~m~~Markets shall be calculated by substituting the Hour-Ahead quantities and prices in the relevant formulae (including self-provided quantities

of the Ancillary Service) except that the user rates for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve capacity shall be calculated by dividing the net payments made by the ISO for each service by the MW quantity purchased for each service. The net payments are the total payments for each service net of sums payable by Scheduling Coordinators who have bought back in the Hour-Ahead Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity, as the case may be, which they had sold to the ISO in the Day-Ahead Market.

Ancillary Services obligations may be negative, and credits for such negative obligations will be in accordance with the rates calculated in Sections 2.5.28.1, 2.5.28.2, 2.5.28.3 and 2.5.28.4, except that a Scheduling Coordinator's credit shall be reduced by the greater of: a) the amount of any self-provision scheduled from resources which are deemed to meet the ISO's Ancillary Services standards, and which are not subject to the certification and testing requirements of the ISO Tariff; or b) if the ISO has no incremental requirement to be met in the Hour-Ahead Market for an Ancillary Service, the incremental amount of such service scheduled by that Scheduling Coordinator in the Hour-Ahead Market.

The ISO will allocate the Ancillary Services capacity charges, for both Day-Ahead and Hour-Ahead Markets, on a Zonal basis if the Day-Ahead Ancillary Services market is procured on a Zonal basis. The ISO will allocate the Ancillary Services capacity charges, for both the Day-Ahead and Hour-Ahead Markets, on an ISO Control Area wide basis if the Day-Ahead Ancillary Services market is defined on an ISO Control Area wide basis.

(b) If, in any Settlement Period, no quantity of Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve is purchased in the Day-Ahead Market or the Hour-Ahead Market due to the operation of Section 2.5.3.6, then in lieu of the user rate determined in accordance with Section 2.5.28.1, 2.5.28.2, 2.5.28.3, or 2.5.28.4, as applicable, the user rate for the affected Ancillary Service for that Settlement Period shall be determined as follows:

(i) If the affected market is a Day-Ahead Market, the user rate for the affected Ancillary Service shall be set at the lowest capacity reservation price for an unaccepted qualified capacity bid in the Day-Ahead Market for the same Settlement Period for that Ancillary Service or for another Ancillary Service that meets the requirements for the affected Ancillary Service. If there are no such unaccepted bids, the user rate for the affected Ancillary Service shall be the lowest Market Clearing Price for the same Settlement Period established in the Day-Ahead Market for another Ancillary Service that meets the requirements for the affected Ancillary Service.

(ii) If the affected market is an Hour-Ahead Market, the user rate for the affected Ancillary Service shall be set at the lowest capacity reservation price for an unaccepted qualified capacity bid in the Hour-Ahead Market for the same Settlement Period for that Ancillary Service or for another Ancillary Service that meets the requirements for the affected Ancillary Service. If there are no such unaccepted bids, the user rate for the affected Ancillary Service shall be the user rate for the same Ancillary Service in the Day-Ahead Market in the same Settlement Period.

(c) With respect to each Settlement Period, in addition to the user rates determined in accordance with Sections 2.5.28.1 through 2.5.28.4 or Section 2.5.28(b), as applicable, each Scheduling Coordinator shall be charged an additional amount equal to its proportionate share, based on total purchases by Scheduling Coordinators of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve of the amount, if any, by which (i) the total payments to Scheduling Coordinators pursuant to Section 2.5.27.1 through 2.5.27.4, for the Day-Ahead Market and Hour-Ahead Market and all Zones, exceed (ii) the total amounts charged to Scheduling Coordinators pursuant to Section 2.5.28.1 through 2.5.28.4, for the Day-Ahead Market and Hour-Ahead Market and all Zones. If total amounts charged to Scheduling Coordinators exceed the total payments to Scheduling Coordinators, each Scheduling Coordinator will be refunded its proportionate share, based on total purchases by Scheduling

Coordinators of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve.

2.5.28.1 Regulation. Regulation Up and Regulation Down charges shall be calculated separately. The user rate per unit of purchased Regulation service for each Settlement Period in the Day-Ahead Market for each Zone shall be calculated by dividing the total Regulation capacity payments by the ISO's total MW purchases of Regulation for that Settlement Period for that Zone which has not been self-provided by Scheduling Coordinators. The ISO will calculate the user rate for Regulation Up in each Zone for each Settlement Period as:

$$RegRateUpDA\ (\$/MW) = AGCUpPayDA\ /AGCUpPurchDA$$

where:

AGCUpPayDA = Total Regulation Up payments for the Settlement Period in the Day-Ahead Market for the Zone.

AGCUpPurchDA = the total ISO Regulation Up MW purchases in the Day-Ahead Market for the Settlement Period for the Zone, excluding that which has been self-provided by Scheduling Coordinators.

The ISO will calculate the user rate for Regulation Down in each Zone for each Settlement Period as:

$$RegRateDownDA\ (\$/MW) = AGCDownPayDA\ /AGCDownPurchDA$$

where:

AGCDownPayDA = Total Regulation Down payments for the Settlement Period in the Day-Ahead Market for the Zone.

AGCDownPurchDA = the total ISO Regulation Down MW purchases in the Day-Ahead Market for the Settlement Period for the Zone, excluding that which has been self-provided by Scheduling Coordinators.

For each Settlement Period, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone:

RegRateUpDA * *AGCUpOblig*

where *AGCUpOblig* is the Scheduling Coordinator's obligation for Regulation Up in the Zone in the Settlement Period for which it has not self-provided.

RegRateDownDA * *AGCDownOblig*

where *AGCDownOblig* is the Scheduling Coordinator's obligation for Regulation Down in the Zone in the Settlement Period for which it has not self-provided.

2.5.28.2 Spinning Reserve. The user rate per unit of purchased Spinning Reserve for each Settlement Period in the Day-Ahead Market for each Zone shall be calculated by dividing the total capacity payments for Spinning Reserve by the ISO's total MW purchases of Spinning Reserve for that Settlement Period for that Zone which has not been self-provided by Scheduling Coordinators. The ISO will calculate the user rate for Spinning Reserve in each Zone for each Settlement Period as:

$$SpRateDA(\$/MW) = \frac{SpinPayDA}{SpinPurchDA}$$

where:

SpinPayDA = Total Spinning Reserve payments for the Settlement Period in the Market for the Zone Day-Ahead.

SpinPurchDA = the total ISO Spinning Reserve MW purchases in the Day-Ahead Market for the Settlement Period for the Zone, excluding that which has been self-provided by Scheduling Coordinators.

For each Settlement Period, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone:

SPRateDA * *SpinOblig*

where *SpinOblig* is the Scheduling Coordinator's obligation for Spinning Reserve in the Zone in the Settlement Period for which it has not self-provided.

2.5.28.3 Non-Spinning Reserve. The user rate per unit of purchased Non-Spinning Reserve for each Settlement Period in the Day-Ahead Market for each Zone shall be calculated by dividing the total capacity payments for Non-Spinning Reserve by the ISO's total MW purchases of Non-Spinning Reserve for that Settlement Period for that Zone which has not been self-provided by Scheduling Coordinators. The ISO will calculate the user rate for Non-Spinning Reserve in each Zone for each Settlement Period as:

$$NonSpRateDA(\$/MW) = \frac{NonSpinPayDA}{NonSpinPurchDA}$$

where:

NonSpinPayDA = Total Non-Spinning Reserve payments for the Settlement Period in the Day-Ahead Market for the Zone.

NonSpinPurchDA = the total ISO Non-Spinning Reserve MW purchases for the Settlement Period for the Zone, excluding that which has been self-provided by Scheduling Coordinators.

For each Settlement Period, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone:

NonSpRateDA * *NonSpinOblig*

where *NonSpinOblig* is the Scheduling Coordinator's obligation for Non-Spinning Reserve in the Zone in the Settlement Period for which it has not self-provided.

2.5.28.4 Replacement Reserve. The user rate per unit of Replacement Reserve obligation for each Settlement Period t for each Zone x shall be as follows:

$$ReplRate_{xt} = \frac{(PRepResDA_{xt} * OrigReplReqDA_{xt}) + (PRepResHA_{xt} * OrigReplReqHA_{xt})}{OrigReplReqDA_{xt} + OrigReplReqHA_{xt}}$$

where

$OrigReplReqDA_{xt}$ = Replacement Reserve requirement net of self-provision in the Day-Ahead Market before consideration of any substitutions pursuant to Section 2.5.3.6.

$OrigReplReqHA_{xt}$ = Incremental change in the Replacement Reserve requirement net of self-provision between the Day-Ahead Market and the Hour-Ahead Market before consideration of any substitutions pursuant to Section 2.5.3.6.

$PRepResDA_{xt}$ is the Market Clearing Price for Replacement Reserve in the Day-Ahead Market for Zone *x* in Settlement Period *t*.

$PRepResHA_{xt}$ is the Market Clearing Price for Replacement Reserve in the Hour-Ahead Market for Zone *x* in Settlement Period *t*.

For each Settlement Period t, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each $Zone_x$:

$ReplRate_{xt} * ReplOblig_{jxt}$

where

$ReplOblig_{jxt} = DevReplOblig_{jxt} + RemRepl_{jxt} - SelfProv_{jxt} + NetInterSCTrades_{jxt}$

$DevReplOblig_{jxt}$ is the Scheduling Coordinator's obligation for deviation Replacement Reserve in Zone x in the Settlement Period t and $RemRepl_{jxt}$ is the Scheduling Coordinator's obligation for remaining Replacement Reserve in Zone x for Settlement Period t.

$SelfProv_{jxt}$ is Scheduling Coordinator's Replacement Reserve self-provision in Zone x for Settlement Period t.

$NetInterSCTrades_{jxt}$ is the sale of Replacement Reserve less the purchase of Replacement Reserve through Inter-Scheduling Coordinator Trades by Scheduling Coordinator j in Zone x for Settlement Period t.

Deviation Replacement Reserve for Scheduling Coordinator j in Zone x for Settlement Period t is calculated as follows:

If $ReplObligTotal_{xt} > TotalDeviations_{xt}$ then:

$$DevReplOblig_{xjt} = \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]$$

If $ReplObligTotal_{xt} < TotalDeviations_{xt}$ then:

$$DevReplOblig_{xjt} = \frac{ReplObligTotal_{xt}}{TotalDeviations_{xt}} * \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]$$

where,

$$TotalDeviations_{xt} = \sum_j \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]$$

$GenDev_{ijxt}$ = The deviation between scheduled and actual Energy Generation for Generator i represented by Scheduling Coordinator j in Zone x during Settlement Period t as referenced in SABP Appendix D.

$LoadDev_{ijxt}$ = The deviation between scheduled and actual Load consumption for resource i represented by Scheduling Coordinator j in Zone x during Settlement Period t as referenced in SABP Appendix D.

$DevReplOblig_{xt}$ is total deviation Replacement Reserve in Zone x for Settlement Period t.

$ReplObligTotal_{xt}$ is total Replacement Reserve Obligation in ~~z~~Zone x for Settlement Period t.

Remaining Replacement Reserve for Scheduling Coordinator j in Zone x for Settlement Period t is calculated as follows:

$$RemRepl_{xjt} = \frac{MeteredDemand_{jxt}}{TotalMeteredDemand_{xt}} * Total\,Re\,m\,Re\,pl_{xt}$$

where:

$MeteredDemand_{jxt}$ is the Scheduling Coordinator's total metered Demand excluding exports in Zone x for Settlement Period t.

$TotalMeteredDemand_{xt}$ is total metered Demand excluding exports in Zone x for Settlement Period t.

$TotalRemRepl_{xt} = Max[0,ReplObligTotal_{xt} + TotalSelfProv_{xt} - DevReplOblig_{xt}]$

2.5.28.5 Voltage Support. The short-term market Voltage Support user rate for Settlement Period t for Zone x shall be calculated as follows:

$$VSSTRate_{xt} = \frac{\sum_{i,j} VSST_{xijt}}{\sum_{j} QChargeVS_{xjt}}$$

$VSST_{xijt}$ = Voltage Support payment to Scheduling Coordinator j in respect of Generating Unit i in Zone x in the short-term market applicable to Settlement Period t.

$QChargeVS_{xjt}$ = charging quantity for Voltage Support for Scheduling Coordinator j for Settlement Period t in Zone x equal to the total metered Demand in Zone x (including exports to neighboring Control Areas and excluding metered Demand inside an MSS) by Scheduling Coordinator j for Settlement Period t.

The monthly long-term Voltage Support contract user rate for Settlement Period t for Zone x shall be calculated as follows:

$$VSLTRate_{xm} = \frac{\sum_{i,j} VSLT_{xijm}}{\sum_{jm} QChargeVS_{xjt}}$$

where:

$VSLT_{xijm}$ = long-term Voltage Support contract payment to Scheduling Coordinator j for owner of Reliability Must-Run Unit i in Zone x for month m.

The short-term market Voltage Support charges for Settlement Period t payable by Scheduling Coordinator j will be calculated as follows:

$$VSSTCharge_{jt} = VSSTRate_{t} * QChargeVS_{jt}$$

where $VSSTCharge_{jt}$ is the amount payable by Scheduling Coordinator j for short-term market Voltage Support for Settlement Period t.

$VSSTRate_t$ is the short-term market Voltage Support user rate for Settlement Period t.

The monthly long-term Voltage Support contract charge for month m payable by Scheduling Coordinator j will be calculated as follows:

$$VSLTCharge_m = VSLTRate_m * \sum_m QCharge VS_{jt}$$

where $VSLTCharge_m$ is the amount payable by Scheduling Coordinator j for long-term Voltage Support for month m.

$VSLTRate_m$ is the monthly long-term Voltage Support contract user rate charged by the ISO to Scheduling Coordinators for month m.

2.5.28.6 Black Start.

$QChargeBlackstart_{jt}$ = charging quantity for Black Start for Scheduling Coordinator j for Settlement Period t equal to the total metered Demand (excluding exports to neighboring Control Areas and metered Demand of a MSS ~~in accordance with Section 3.3.4.5~~) by Scheduling Coordinator j for Settlement Period t.

The Black Start Energy payment user rate for Settlement Period t will be calculated as follows:

$$BSRate_t = \frac{\sum_{i,j} BSEn_{ijt}}{\sum_j QChargeBlackstart_{jt}}$$

where $BSEn_{ijt}$ is the ISO payment to Scheduling Coordinator j for owner of Reliability Must-Run Unit (or to Black Start Generator j, as the case may be) for Generating Unit i providing Black Start Energy in Settlement Period t.

The Black Start Energy user charge for Settlement Period t for Scheduling Coordinator j will be calculated as follows:

$$BSCharge_{jt} = BSRate_t * QChargeBlackStart_{jt}$$

2.5.29 Public Dissemination of Information: Day-Ahead.

By 3:00 p.m. of the day preceding the Trading Day, the ISO shall make available to all Market Participants the following information on the scheduling of Ancillary Services:

Ancillary Service	Quantity Units	Period	Clearing Prices
Regulation/AGC	MW	Hourly	$/MW
Spinning Reserve	MW	Hourly	$/MW
Non-sSpinning Reserve	MW	Hourly	$/MW
Replacement Reserve	MW	Hourly	$/MW
Black Start	MW	Annual	$/MW

3. RELATIONSHIP BETWEEN ISO AND PARTICIPATING TOs.

* * *

3.2.1 Determination of Need.

A Participating TO or any other Market Participant may propose a transmission system addition or upgrade. The ISO will determine that a transmission addition or upgrade is needed where it will promote economic efficiency or maintain ~~s~~System ~~r~~Reliability as set forth below.

* * *

3.2.1.2 Reliability Driven Projects. The ISO in coordination with the Participating TO, will identify the need for any transmission additions or upgrades required to ensure ~~s~~System ~~r~~Reliability consistent with all Applicable Reliability Criteria. In making this determination, the ISO, in coordination with the Participating TO and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as acceleration or expansion of existing projects, demand-side management, remedial action schemes, constrained-on Generation, interruptible Loads or reactive support. The Participating TO, in cooperation with the ISO, shall perform the necessary studies to determine the facilities needed to meet all Applicable Reliability Criteria. The Participating TO shall provide the ISO and other Market Participants with all information relating to a proposed transmission addition or upgrade that they may reasonably request (other than information available to them through the W~~S~~ECC or any other applicable regional organization) and shall, through the W~~S~~ECC or any other applicable regional organization coordinated planning processes, develop the scope of and assumptions for such studies that are acceptable to the ISO and those other Market Participants. The ISO shall be free to propose any transmission upgrades or additions it deems necessary to ensure System Reliability consistent with Applicable Reliability Criteria, and, subject to appropriate appeals, the Participating TO shall be obligated to construct such lines.

After the ISO Operations Date, the ISO, in consultation with Participating TOs and any affected UDCs and MSSs, will work to develop a consistent set of ~~r~~Reliability ~~c~~Criteria for the ISO Controlled Grid which the Participating TOs will use in their transmission planning and expansion studies or decisions.

* * *

3.2.2.3 The Participating TO will act as a Project Sponsor for Participating TO proposed economic or reliability projects that are included in its expansion plan. The Participating TO shall provide to the ISO any information that the ISO requires to enable the ISO to comply with WS~~E~~ECC and any other applicable regional coordination requirements pursuant to Section 3.2.6.

3.2.2.4 The ISO will be a member of the WS~~E~~ECC and other applicable regional organizations and participate in WS~~E~~ECC's operation and planning committees, and in other applicable regional coordinated planning processes. Neither the ISO nor ~~e~~any Participating TO~~,~~ nor any Market Participant ~~nor the ISO~~ shall take any position before the WS~~E~~ECC or a regional organization that is inconsistent with a binding decision reached through the ISO ADR Procedure.

* * *

3.2.6 WS~~E~~ECC and Regional Coordination.

The Project Sponsor will have responsibility for completing any applicable WS~~E~~ECC requirements and other applicable regional coordination and rating study requirements to ensure that a proposed transmission addition or upgrade meets regional planning requirements. The Project Sponsor may request the Participating TO to perform this coordination on behalf of the Project Sponsor at the Project Sponsor's expense.

* * *

4. RELATIONSHIP BETWEEN ISO AND UDCS.

* * *

4.1.2 The ISO shall operate the ISO Controlled Grid, and each UDC shall operate its ~~d~~Distribution ~~s~~System at all times in accordance with Good Utility Practice and in a manner which ensures safe and reliable operation. The ISO shall, in respect of its obligations set forth in this Section 4, have the right by agreement to delegate certain operational responsibilities to the relevant Participating TO or UDC pursuant to this Section 4. All information made available to UDCs by the ISO shall also be made available to Scheduling Coordinators. All information pertaining to the physical state or operation, maintenance and failure of the UDC Distribution System affecting the operation of the ISO Controlled Grid that is made available to the ISO by the UDC shall also be made available to Scheduling Coordinators upon receipt of reasonable notice.

4.2 Coordinating Maintenance Outages of UDC Facilities.

Each UDC and the Participating TO with which it is interconnected shall coordinate their Outage requirements that will have an effect on their transmission interconnection prior to the submission by that Participating TO of its ~~m~~Maintenance Outage requirements under Section 2.3.3.

* * *

4.5.3 Load Shedding

4.5.3.1 A portion of the ISO forecast of Control Area Load for each Trading Day will be allocated to each UDC or MSS Service Area. The ISO will aggregate each Scheduling Coordinator's Day-Ahead Schedules to Load in each UDC or MSS Service Area and will compare those aggregated Load Schedules to the ISO's Control Area Load forecast of metered Demand for that UDC or MSS Service Area to determine if the Load in the UDC or MSS Service Area has a resource deficiency based on the Day-Ahead Schedules.

4.5.3.2 If the ISO forecasts in advance of the Hour-Ahead Market that Load curtailment will be necessary due to a resource deficiency, the ISO will identify any UDC or MSS Service Area that is resource deficient. The ISO will provide notice to all Scheduling Coordinators if one or more UDC or MSS is deficient. If Load curtailment is required to manage a System Emergency associated with insufficient Hour-Ahead Schedules of resources, the ISO will determine the amount and location of Load to be curtailed and will allocate a portion of that required Load curtailment to each UDC or MSS Operator whose Service Area has been identified, based on Hour-Ahead Schedules, as being resource-deficient based on the ratio of its resource deficiency to the total Control Area resource deficiency. Each UDC or MSS Operator shall be responsible for notifying its customers and Generators connected to its system of curtailments and service interruptions.

* * *

4.8 Information Sharing.

4.8.1 System Planning Studies.

The ISO, Participating TOs and UDCs shall share information such as projected Load growth and system expansions necessary to conduct necessary ~~s~~System ~~p~~Planning ~~s~~Studies to the extent that these may impact the operation of the ISO Controlled Grid.

* * *

5. RELATIONSHIP BETWEEN ISO AND GENERATORS.

* * *

5.2 Procurement of Reliability Must-Run Generation by the ISO.

* * *

5.2.1.2 If, at any time after the issuance of Final Day-Ahead Schedules for the Trading Day –

(1) the ISO determines that it requires more of an Ancillary Service than it has procured;

(2) all additional Day-Ahead bids for that Ancillary Service that have not been withdrawn (including any unused bids that can be used to satisfy that particular Ancillary Services requirement under Section 2.5.3.6) have been selected pursuant to Section 2.5.21, except that the ISO shall not be required to accept bids that exceed price caps imposed by the ISO or the FERC;

(3) the ISO has notified Scheduling Coordinators of the circumstances existing in paragraphs (1) and (2) of this Section 5.2.1.2; and

(4) after such notice, the ISO determines that a Bid Insufficiency condition exists in the Hour-Ahead Market for the Settlement Period in which the ISO requires more of an Ancillary Service;

the ISO may call upon Reliability Must-Run Units under Reliability Must-Run Contracts to meet the additional needs in addition to any amounts that the ISO has called upon under Section 5.2.1.1. The ISO must provide the notice specified in paragraph (3) of this Section 5.2.1.2 as soon as possible after the ISO determines that additional Ancillary Services are needed for which bids are not available. The ISO may only determine that a Bid Insufficiency exists in the Hour-Ahead Market after the close of the Hour-Ahead Market, unless an earlier determination is required in order to accommodate the Reliability Must-Run Unit's operating constraints. For the purposes of this Section, a Bid Insufficiency exists in an Hour-Ahead Market if, and only if –

(a) bids in the Hour-Ahead Market for the particular Ancillary Service (including any unused bids that can be used to satisfy that particular Ancillary Services requirement under Section 2.5.3.6) that remain after first procuring the megawatts of the Ancillary Service that the ISO had notified Scheduling Coordinators it would procure in the Hour-Ahead Market pursuant to Section 2.5.12 ("remaining Ancillary Service requirement") represent, in the aggregate, less than two times such remaining Ancillary Service requirement; or

(b) there are less than two unaffiliated bidders to provide such remaining Ancillary Service requirement.

If a Bid Insufficiency condition exists, the ISO may nonetheless accept available market bids if it determines in its sole discretion that the prices bid and the supply curve created by the bids indicate that the bidders were not attempting to exercise market power.

* * *

5.2.5 On a yearly basis, the ISO will carry out technical evaluations based upon historic patterns of the operation of the ISO Controlled Grid and the ISO's forecast requirements for maintaining the reliability of the ISO Controlled Grid in the next year. The ISO will then determine which Generating Units it requires to continue to be Reliability Must-Run Units, which Generating Units it no longer requires to be Reliability Must-Run Units and which Generating Units it requires to become the subject of a Reliability Must-Run eContract which had not previously been so contracted to the ISO.

5.2.6 A *pro forma* of the Reliability Must-Run Contract is attached as Appendix G. From the ISO Operations Date all Reliability Must-Run Units will be placed under the "As Called" conditions, but the parties may, pursuant only to the terms of the Reliability Must-Run Contract, Transfer any such unit to one of the alternative forms of conditions under specific circumstances. The ISO will review the terms of the applicable forms of agreement applying to each Reliability Must-Run Unit to ensure that the ISO will procure Reliability Must-Run Generation from the cheapest available sources and to maintain System Reliability. The ISO shall give notice to terminate Reliability Must-Run eContracts that are no longer necessary or can be replaced by less expensive and/or more competitive sources for maintaining the reliability of the ISO Controlled Grid.

* * *

5.2.7.1.1 If the Responsible Utility disputes an ISO Invoice, Revised Estimated RMR Invoice, or Revised Adjusted RMR Invoice, or Final Invoice, it shall pay the ISO Invoice but may pay under protest and reserve its right to seek a refund, with interest, from the ISO. If resolution of the dispute results in an amount paid by the Responsible Utility under protest being due from the ISO to the Responsible Utility and from the RMR Owner to the ISO, and such amount was paid to the RMR Owner by the ISO, then such amount, with interest at the interest rate specified in the applicable Reliability Must-Run Contract from the date of payment until the date on which the amount is repaid in full, shall be refunded by the RMR Owner to the ISO and from the ISO to the Responsible Utility, pursuant to Article 9 of the Reliability Must-Run Contract and Annex 1 to the ISO's Settlement and Billing Protocol, by the RMR Owner's inclusion of such refund amount in the appropriate invoice. If the RMR Owner does not include such refund amount (including interest) in the appropriate invoice, then such refund amount shall be deducted by the ISO from the next succeeding amounts otherwise due from the Responsible Utility to the ISO and from the next succeeding amounts otherwise due from the ISO to the RMR Owner with respect to the applicable Reliability Must-rRun Contract or, if such Contract has terminated, such amount shall be refunded by the ISO to the Responsible Utility; provided, however, that if and to the extent that such resolution is based on an error or breach or default of the RMR Owner's obligations to the ISO under the Reliability Must-Run Contract, then such refund obligation shall extend only to amounts actually collected by the ISO from the RMR Owner as a result of such resolution. If resolution of the dispute requires the ISO, but not the RMR Owner, to pay the Responsible Utility, then such award shall be recovered from any applicable insurance proceeds, provided that to the extent sufficient funds are not recoverable through insurance, the amount of the award (whether determined through settlement, or ADR or otherwise) shall be collected by the ISO pursuant to Section 13.5, and in any event, the award shall be paid by the ISO to the Responsible Utility pursuant to Section 13.5.

* * *

5.2.7.1.3 If the Responsible Utility disputes an ISO Invoice, a Revised Estimated RMR Invoice, a Revised Adjusted RMR Invoice, or a Final Invoice, based in whole or in part on an alleged error by the ISO or breach or default of the ISO's obligations to the Responsible Utility, the Responsible Utility shall notify the ISO of such dispute prior to the later to occur of (i) the date 12 months following the date on which the ISO submitted such invoice to the Responsible Utility for payment or (ii) the date 60 days following the date on which a final report is issued in connection with an operational audit, pursuant to Section 12.2.2, of the ISO's performance of its obligations to Responsible Utilities under this Section 5.2.7 conducted by an independent third party selected by the ISO Governing Board and covering the period to which such alleged dispute relates. The ISO or any Responsible Utility shall have the right to request, but not to require, that the ISO Governing ~~b~~Board arrange for such an operational audit at any time.

* * *

5.4 WS~~E~~ECC Requirements.

5.4.1 Generator Performance Standard.

Participating Generators shall, in relation to each of their Generating Units, meet all applicable WS~~E~~ECC standards including any standards regarding governor response capabilities, use of power system stabilizers, voltage control capabilities and hourly Energy delivery. Unless otherwise agreed by the ISO, a Generating Unit must be capable of operating at capacity registered in the ISO Controlled Grid interconnection data, and shall follow the voltage schedules issued by the ISO from time to time.

5.4.2 Reliability Criteria.

Participating Generators shall comply with the requirements of the WSCC Reliability Criteria Agreement, including the applicable WSCC ~~r~~Reliability ~~c~~Criteria set forth in Section IV of Annex A thereof. In the event that a Participating Generator fails to comply, it will be subject to the sanctions applicable to such failure. Such sanctions shall be assessed pursuant to the

procedures contained in the WSCC Reliability Criteria Agreement. Each and all of the provisions of the WSCC Reliability Criteria Agreement are hereby incorporated by reference into this Section 5.4.2 as though set forth fully herein, and Participating Generators shall for all purposes be considered Participants as defined in that Agreement, and shall be subject to all of the obligations of Participants, under and in connection with the WSCC Reliability Criteria Agreement. The Participating Generators shall copy the ISO on all reports supplied to the WSECC in accordance with Section IV of Annex A of the WSCC Reliability Criteria Agreement.

5.4.3 Payment of Sanctions.

Each Participating Generator shall be responsible for payment directly to the WSECC of any monetary sanction assessed against that Participating Generator by the WSECC pursuant to the WSCC Reliability Criteria Agreement. Any such payment shall be made pursuant to the procedures specified in the WSCC Reliability Criteria Agreement.

5.5 Outages.

5.5.1 Planned Maintenance.

Each Participating Generator shall comply with the applicable provisions of Section 2.3.3.

5.5.2 The ISO shall, on the basis of the information supplied by Participating Generators under Section 5.5.1 and other information available to the ISO, prepare and publish on WEnet forecast aggregate available Generation capacity and forecast Demand on an annual, quarterly and monthly basis in accordance with the provisions of the ISO Outage Coordination Protocol. In publishing these forecasts, the ISO shall identify any expected eCongestion conditions caused by planned Outages of Participating Generators.

* * *

5.7.4.2.1 System Impact Study Procedures.

Within 10 Business Days after receiving a Completed Interconnection Application by the Interconnecting PTO, the ISO and the Interconnecting PTO will determine, on a non-discriminatory basis, whether a System Impact Study is required. The ISO and the Interconnecting PTO will make such determination based on the ISO Grid Planning Criteria and the transmission assessment practices outlined in the ISO Planning Procedures posted on the ISO Home Page. The ISO and Interconnecting PTO will utilize, to the extent possible, existing transmission studies. The System Impact Study will identify whether any Direct Assignment Facilities and Reliability Upgrades are needed, as well as, if requested by the New Facility Operator, any Delivery Upgrades necessary to deliver a New Facility's full output over the ISO Controlled Grid. The System Impact Study will also identify any adverse impact on Encumbrances existing as of the Completed Application Date.

If the ISO and the Interconnecting PTO determine that a System Impact Study is necessary, the Interconnecting PTO shall within 20 Business Days of receipt of Completed Interconnection Application, tender a System Impact Study Agreement that defines the scope, content, assumptions and terms of reference for such study, the estimated time required to complete it, and pursuant to which the applicant shall agree to reimburse the Interconnecting PTO for the reasonable actual costs of performing the required study. The New Facility Operator shall execute the System Impact Study Agreement and return it to the Interconnecting PTO within 10 Business Days, together with payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the System Impact Study. Alternatively, a New Facility Operator can request that the Interconnecting PTO proceed with the System Impact Study and abide by the terms, conditions, and cost assignment of the System Impact Study Agreement as determined through the ISO ADR Procedures, provided that such request is accompanied by payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the System Impact Study. If a New Facility Operator elects neither to execute the System Impact Study Agreement nor to rely upon the ISO ADR Procedures, such New Facility Operator's Completed Application

will be deemed withdrawn. If the New Facility Operator's application is deemed withdrawn, the New Facility Operator will compensate the Interconnecting PTO for all reasonable costs incurred to that date in processing the Completed Interconnection Application.

The Interconnecting PTO will use due diligence to complete the System Impact Study within 60 ~~C~~calendar ~~D~~days of receipt of payment and the System Impact Study Agreement or initiation of the ISO ADR Procedures. If the Interconnecting PTO cannot complete the System Impact Study within 60 ~~C~~calendar ~~D~~days, the Interconnecting PTO will notify the New Facility Operator, in writing, of the reason why additional time is required to complete the required study and the estimated completion date.

5.7.4.2.2 Facility Study Procedures.

If a System Impact Study indicates that additions or upgrades to the ISO Controlled Grid are needed to satisfy a New Facility Operator's request for interconnection, the Interconnecting PTO shall, within 15 Business Days of the completion of the System Impact Study, tender to a New Facility Operator a Facility Study Agreement that defines the scope, content, assumptions and terms of reference for such study, the estimated time to complete the required study, and pursuant to which the applicant agrees to reimburse the Interconnecting PTO for the actual costs of performing the required Facility Study. The New Facility Operator shall execute the Facility Study Agreement and return it to the Interconnecting PTO within 10 Business Days, together with payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the Facility Study. Alternatively, a New Facility Operator may request that the Interconnecting PTO proceed with the Facility Study and abide by the terms, conditions, and cost assignment of the Facility Study Agreement ultimately determined through the ISO ADR Procedures, provided that such request is accompanied by payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the Facility Study. If a New Facility Operator elects either to not execute the Facility Study Agreement or to rely upon the ISO ADR Procedures, such New Facility Operator's Completed Application will be deemed withdrawn. If the New Facility Operator's application is deemed withdrawn, the New Facility Operator will

compensate the Interconnecting PTO for all reasonable costs incurred to that date in processing the Completed Application.

The Interconnecting PTO will use due diligence to complete the Facility Study within 60 ~~C~~calendar ~~D~~days of receipt of payment and the Facility Study Agreement or initiation of the ISO ADR Procedures. If the Interconnecting PTO cannot complete the Facility Study within 60 ~~C~~calendar ~~D~~days, the Interconnecting PTO will notify the New Facility Operator, in writing, of the reason why additional time is required to complete the required study and the estimated completion date.

A New Facility Operator shall be entitled to amend its Completed Interconnection Application once without losing its queue position. Such amendment shall occur on or before 10 Business Days following the Date the Interconnecting P~~O~~TO tenders a Facility Study Agreement. Specifically, as an alternative to executing and returning a Facility Study Agreement, a New Facility Operator may submit an amendment to its Completed Interconnection Application to reflect a revised configuration for its New Facility. The amended Completed Interconnection Application shall be treated in accordance with Section 5.7.4.2.1 and the New Facility ~~o~~Operator's Completed Interconnection Application shall not be deemed withdrawn, and it shall maintain its exiting queue position, if (a) the amended Completed Interconnection Application is received by the Interconnecting PTO within 10 Business Days of the Interconnecting PTO's tender of a Facility Study Agreement; and (b) the New Facility Operator has not submitted a previous amendment to the Completed Interconnection Application. In the event a New Facility Operator amends its Completed Interconnection Application, it will be responsible for any additional study costs that result from that amendment, including costs associated with revisions to studies for other applicants holding later queue positions.

5.7.4.3 Execution of Interconnection Agreement.

Within 10 Business Days of receipt of a completed Facility Study, a New Facility Operator shall request the Interconnecting PTO to provide to such applicant an Interconnection Agreement. The Interconnecting PTO shall provide an Interconnection Agreement to an applicant within 30

Business Days of receipt of the request for an Interconnection Agreement. If the ISO and Interconnecting PTO determine, pursuant to Sections 5.7.4.2.1 and 5.7.4.2.2, that either:

(a) a New Facility Operator's Interconnection Application can be accommodated and that such New Facility Operator will not incur costs for Reliability Upgrades, the New Facility Operator shall execute the Interconnection Agreement within 10 Business Days of receipt of the Interconnection Agreement; or

(b) a New Facility Operator's Interconnection Application will necessitate Reliability Upgrades, the New Facility Operator shall execute the Interconnection Agreement within 30 Business Days of receipt of the Interconnection Agreement or, if a New Facility Operator and the Interconnecting PTO are unable to agree on the rates, terms and conditions of the Interconnection Agreement, the New Facility Operator may request that the Interconnecting PTO file an unexecuted Interconnection Agreement at FERC. If a New Facility Operator does request that the Interconnecting PTO file an unexecuted Interconnection Agreement at FERC, the New Facility Operator shall agree to abide by the rates, terms and conditions of such Interconnection Agreement ultimately determined by FERC to be just and reasonable.

* * *

5.7.4.4.1 Queuing Milestones.

(a) To maintain its queue position, each New Facility Operator must timely comply with the requirements of the ISO Tariff and the TO tTariff of the Interconnecting PTO and must, within 6 months of its Completed Application Date, satisfy all applicable Data Adequacy Requirements of state and local siting and other regulatory authorities. Any New Facility Operator not subject to state siting requirements must satisfy the information requirements set forth in 18 C.F.R. § 2.20. The ISO will permit a New Facility Operator to retain its queue position if such New Facility Operator requests an extension of the six-month period at least 5 Business Days prior to the expiration of such period. Such extension will be limited to one period of 30 Business Days and additional extensions

shall not be granted. A New Facility Operator that does not maintain its queue position, but later satisfies the Data Adequacy Requirements, or the requirements of 18 C.F.R. § 2.20 if applicable, will be placed in a queue position comparable to that of other New Facility Operators that have satisfied the Data Adequacy Requirements, or the requirements of 18 C.F.R. § 2.20, as of the same date. At that time, the ISO and the Interconnecting PTO will determine whether a new System Impact Study must be performed based on the revised queue position of such New Facility Operator.

(b) Upon satisfaction of the Data Adequacy Requirements, or the requirements of 18 C.F.R. § 2.20 if applicable, each New Facility Operator, in order to maintain its queue position, must obtain a New Facility License within 15 months after satisfying the Data Adequacy Requirements. A New Facility Operator that does not obtain a New Facility License within the allowed time and does not maintain its queue position, but later obtains a New Facility License, will be placed in a queue position comparable to other New Facility Operators that have satisfied comparable milestones as of that date.

(c) Any New Facility whose New Facility License or building permit expires or is rescinded will not maintain its queue position.

(d) A New Facility Operator that has submitted a dispute under Article 13 of the ISO Tariff regarding any part of this Section 5.7 may request that the presiding judge, arbitrator, or mediator of the dispute suspend its obligation to meet milestones in order to maintain its queue position. In the event such a suspension is granted, the New Facility Operator must satisfy the missed milestones specified in this Section 5.7.4.4.1 within 30 calendar days of the date the decision on the dispute becomes final.

* * *

5.7.6 Energization.

Neither the ISO nor the Interconnecting PTO shall be obligated to energize, nor shall the New Facility Operator be entitled to have its interconnection to the ISO Controlled Grid energized,

unless and until an Interconnection Agreement has been executed, or filed at FERC pursuant to Section 5.7.4.3, and becomes effective and such New Facility Operator has demonstrated to the ISO's reasonable satisfaction that it has complied with all of the requirements of this Section 5.7~~2~~.

* * *

5.9 Access Right.

A Participating Generator shall, at the request of the ISO and upon reasonable notice, provide access to its facilities (including those relating to communications, telemetry and direct control requirements) as necessary to permit the ISO or an ISO approved meter inspector to perform such testing as is necessary (i) to test the accuracy of any meters upon which the Participating Generator's compensation is based, or performance is measured, (ii) to test the Participating Generator's compliance with any performance standards pursuant to ~~subs~~Section 5.4 ~~here~~of this ISO Tariff, or (iii) to obtain information relative to a Forced Outage.

* * *

5.11.2 Available Generation

For the purposes of this Section 5.11, a Must-Offer Generator's "Available Generation" from a non-hydroelectric Generating Unit shall be: (a) the Generating Unit's maximum operating level adjusted for any outages or reductions in capacity reported to the ISO in accordance with Section 2.3 or 5.11.3 and for any limitations on the Generating Unit's operation under applicable law, including contractual obligations, which shall be reported to the ISO, (b) minus the Generating Unit's scheduled operating point as identified in the ISO's Final Hour-Ahead Schedule, (c) minus the Generating Unit's capacity committed to provide Ancillary Services to the ISO either through the ISO's Ancillary Services market or through self-provision by a Scheduling Coordinator, and (d) minus the capacity of the Generating Unit committed to deliver Energy or provide Operating Reserve to the Must-Offer Generator's Native Load.

* * *

5.11.6 Waiver of Must-Offer Obligation

Must-Offer Generators may seek a waiver of the obligation to offer all available capacity, as set forth in Section 5.11.4 of this ISO Tariff, for one or more of their ~~g~~Generating ~~u~~Units for periods other than Self-Commitment Periods, which are defined as the hours when Must-Offer Generators submit Energy Schedules or are awarded Ancillary Services bids or self-provision schedules. Self-Commitment Periods determined from Day-Ahead Schedules shall be extended by the ISO as necessary to accommodate ~~g~~Generating ~~u~~Unit minimum up and down times such that the scheduled operation is feasible.

All other Must-Offer Generators obligated under the ~~M~~must-~~O~~offer ~~O~~obligation will be deemed to have requested a waiver, either implicitly or explicitly, of the obligation to offer all available capacity. If conditions permit, and at the ISO's non-discriminatory and sole discretion, the ISO may grant waivers and allow a Must-Offer Generator to remove one or more ~~g~~Generating ~~u~~Units from service during hours outside Self-Commitment Periods. The ISO shall grant waivers so as to: 1) provide sufficient on-line generating capacity to meet ~~o~~Operating ~~r~~Reserve requirements; and 2) account for other physical operating constraints, including ~~g~~Generating ~~u~~Unit minimum up and down times. The hours outside of Self-Commitment Periods for which waivers are not granted shall constitute Waiver Denial Periods. The Waiver Denial Period shall be extended as necessary to accommodate ~~g~~Generating ~~u~~Unit minimum up and down times. Units shall be on-line in real time during both Self-Commitment and Waiver Denial Periods, or they will be in violation of the must-offer obligation. Exceptions shall be allowed for verified forced outages. The must-offer obligation will remain in effect for a unit's Self-Commitment Period even if the Must-Offer Generator nullifies its Day-Ahead ~~Energy~~ Schedules for Energy or buys back its Day-Ahead Schedules for a unit in the Hour-Ahead ~~m~~Market. The ISO may revoke waivers as necessary due to outages, changes in Load forecasts, or changes in system conditions. The ISO shall determine which waiver(s) will be revoked, and shall notify the relevant Scheduling Coordinator(s). The ISO shall inform a Must-Offer Generator that its Waiver request has been accepted, denied, or revoked, and shall provide the Must-Offer Generator with the reason(s) for

the decision, which reasons shall be non-discriminatory. The ISO will: (1) notify Must-Offer Generators of the ISO decisions on pending Waiver requests received no later than 6:00 p.m. (beginning of Hour Ending 19) no later than 8:00 p.m. (beginning of Hour Ending 21) on the day before the operating day for which the Waivers are requested; (2) at any time but no later than 8:00 p.m. on the following day, notify Must-Offer Generators of the ISO decisions on Waiver requests that were submitted to the ISO after 6:00 p.m. (beginning of Hour Ending 19) on the day before; (3) end Waiver Denial Periods at any time; and (4) revoke Waivers at any time, while making best attempts to revoke a Waiver at least 90 minutes prior to time a unit would be required to be on-line generating at its Pmin.

5.11.6.1 Recovery of Minimum Load Costs By Must-Offer Generators

5.11.6.1.1 Eligibility

Units from Must-Offer Generators that incur Minimum Load Costs during Self-Commitment Periods or during hours for which the ISO has granted to them a waiver shall not be eligible to recover such costs for such hours. When a Must-Offer Generator is awarded Ancillary Services in the Hour-Ahead ~~m~~Market or has a Final Hour-Ahead Schedule other than a Schedule to a unit-specific Demand ID used for the purpose of scheduling minimum load energy as set forth in Section 5.11.6, the Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. When, on a 10-minute Settlement Interval basis, a Must-Offer Generator generating at ~~M~~minimum ~~L~~load in compliance with the ~~M~~must-~~O~~offer ~~O~~obligation, produces a quantity of Energy that varies by more than the Tolerance Band, the Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such Settlement Intervals during hours within a Waiver Denial Period. When, on a Settlement Interval basis, a Must-Offer Generator's resource produces a quantity of Energy above ~~M~~minimum ~~L~~load due to an ISO Dispatch Instruction, the Must-Offer Generator shall recover its Minimum Load Costs and its bid costs, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance

Band. Subject to the foregoing eligibility restrictions set forth in this section, the ISO shall guarantee recovery of the Minimum Load Costs of an otherwise eligible Must-Offer Generator for each Settlement Interval during hours within a Waiver Denial Period as follows: (1) First, ISO will pre-dispatch for ~~R~~real-time the ~~M~~minimum ~~L~~load Energy from Must-Offer Generators that have been denied waivers for each hour within a Waiver Denial Period; (2) This ~~M~~minimum ~~L~~load Energy will be accounted as Instructed Imbalance Energy for each Settlement Interval within the relevant hour and be settled at the Resource-Specific Settlement Interval Ex Post ~~p~~Price; (3) To the extent the Instructed Imbalance Energy payments are not sufficient to cover the generator's Minimum Load Cost for the hour as defined in Section 5.11.6.1.2 of this Tariff, the generator will also receive an uplift payment for its Minimum Load Cost ~~C~~compensation for the relevant eligible Settlement Intervals of hours during the Waiver Denial Period that the ~~g~~Generating ~~u~~Unit runs at ~~M~~minimum ~~L~~load in compliance with the ~~M~~must-~~O~~offer ~~O~~obligation; and (4) To the extent the Generator is dispatched for ~~R~~real-time Imbalance Energy above its minimum load for any Dispatch Interval within an hour during the Waiver Denial Period, the Generator will be eligible for Bid Cost Recovery, as set forth in Section 11.2.4.1.1.1.

* * *

5.11.6.1.3 Invoicing Minimum Load Costs

The ISO shall determine each Scheduling Coordinator's Minimum Load Costs and make payments for these costs as part of the ISO's market settlement process. Scheduling Coordinators may submit to the ISO data detailing the hours for which they are eligible to recover Minimum Load Costs. Scheduling Coordinators who elect to submit data on hours they are eligible to recover Minimum Load Costs must: 1) use the Minimum Load Cost ~~I~~invoice template posted on the ISO Home Page, and 2) submit the invoice on or before fifteen (15) ~~b~~Business ~~d~~Days following the last Trading Day in the month in which such costs were incurred, except that Scheduling Coordinators seeking reimbursement for Minimum Load Costs incurred between May 29, 2001, and June 30, 2002 must submit their data to the ISO by August 5, 2002.

* * *

5.11.6.1.5 Payment Of Available Capacity Under The Must-Offer Obligation

Available capacity that is required to be offered to the Real Time Market, if dispatched by the ISO, shall be settled as follows: the actual amount of the dispatched Energy shall be settled at the applicable Instructed Imbalance Energy Market Clearing Price. Minimum Load Cost ~~C~~compensation shall be paid for all otherwise eligible hours within the Waiver Denial Period, as defined in Section 5.11.6.1.1, that the unit generated above ~~M~~minimum ~~L~~load in compliance with ISO Dispatch Instructions.

5.12 [Not Used]

5.13 Energy Bids.

5.13.1 Energy Bid Definition.

A single Energy Bid curve per resource per hour shall be used in: (a) the ~~R~~real-~~T~~time Hourly Pre-Dispatch as set forth in Dispatch Protocol 8.6.3, and (b) Dispatch in the Real Time Markets. A corresponding operational ramp rate as provided for in SBP Section 6.5 shall be submitted along with the single Energy Bid curve and shall be used in determination of Dispatch Instructions pursuant to Section 2.5.22.6.1(c).

The Energy Bid shall be a staircase price ($/MWh) versus quantity (MW) curve of up to 10 segments. The Energy Bid shall be submitted to the ~~R~~real-~~T~~time Imbalance Energy ~~M~~market using the Supplemental Energy Bid template. The Energy Bid curve shall be monotonically increasing, i.e., the price of a subsequent segment shall be greater than the price of a previous segment. Subject to the foregoing, sellers may increase or decrease bids in the ISO Real Time Market for capacity associated with those parts of the bid curve that were not accepted in or before the Hour-Ahead Market. For capacity associated with those parts of the bid curve previously accepted in or before the Hour-Ahead Market, sellers may only submit lower bids in

subsequent markets. Each Forbidden Operating Region must be represented by only one bid segment.

5.13.2 Energy Bid Submission.

5.13.2.1 Real Time Market. Bids shall be submitted for use in the ~~R~~real-~~T~~time Hourly Pre-Dispatch in DP 8.6.3(j) and the Real-Time Economic Dispatch up to sixty (60) minutes prior to the Operating Hour. Resources required to offer their Available Generation in accordance with Section 5.11.4 shall be required to submit Energy Bids for 1) all of their Available Generation and 2) any Ancillary Services capacity awarded or self-provided in the Day-Ahead or Hour-Ahead Ancillary Services markets. In the absence of submitted bids, default bids will be used for resources required to offer their Available Generation in accordance with Section 5.11.4. Resources not required to offer their Available Generation in accordance with Section 5.11.4 that were awarded or self-provided Ancillary Services capacity must submit an Energy Bid for no less than the amount of awarded or self-provided Ancillary Services capacity. Resources not required to offer their Available Generation in accordance with Section 5.11.4 may voluntarily submit Energy Bids. Submitted Energy Bids shall be subject to the Damage Control Bid Cap as set forth in Section 28.1 and to the Mitigation Measures set forth in Appendix A to the Market Monitoring and Information Protocol.

5.13.2.2 Real-~~t~~Time Energy Bid Partition. The portion of the single Energy Bid that corresponds to the high end of the resource's operating range, shall be allocated to any awarded or self-provided Ancillary Services in the following order from higher to lower capacity: (a) Regulation Up; (b) Spinning Reserve; (c) Non-Spinning Reserve; and (d) Replacement Reserve. For resources providing Regulation Up, the upper regulating limit shall be used if it is lower than the highest operating limit. The remaining portion of the Energy Bid (i.e. that portion not associated with capacity committed to provide Ancillary Services) shall constitute a Bid to provide Supplemental Energy.

5.13.3 Requirement to Submit Energy Bids For Awarded or Self-Provided Ancillary Services Capacity

Scheduling Coordinators for resources that have been awarded or self-provide Regulation Up, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity must submit a Supplemental Energy bid for at least all the awarded or self-provided Ancillary Services capacity. To the extent a Supplemental Energy bid is not so submitted for a gas-fired resource, the ISO shall calculate a Supplemental Energy bid in accordance with Section 2.5.23.3.4 and insert that bid into the ~~R~~real-~~T~~time Imbalance Energy ~~M~~market. To the extent a Supplemental Energy bid is not so submitted for a non-gas-fired resource, the ISO shall insert a bid of $0/MWh into the ~~R~~real-~~T~~time Imbalance Energy ~~M~~market.

6. TRANSMISSION SYSTEM INFORMATION AND COMMUNICATIONS.

* * *

6.1.2.2.2 Day-Ahead and Hour-Ahead Information:

(a) Date;

(b) Hour;

(c) Total forecast Demand by UDC;

(d) Inter-Zonal Congestion price per Congested path; Total Regulation and Reserve service capacity reservation cost by Zone;

(e) Total capacity of Inter-Zonal Interfaces; and

(f) Available capacity of Inter-Zonal Interfaces.

* * *

6.1.2.5 WEnet may be used by the ISO to communicate operating orders to the Scheduling Coordinators and other Market Participants, both in advance of actual operation and in real time. Such orders may include but are not limited to:

(a) Notifying Scheduling Coordinators and other Market Participants to be on call to provide Non-Spinning Reserve and Replacement Reserves and Black Start;

(b) Issuing start-up instructions;

(c) Stating the amount of Spinning Reserves to be carried;

(d) Requesting specific Ramping patterns;

(e) Indicating which Scheduling Coordinators and other Market Participants are to provide Regulation;

(f) Specifying the minimum amount of unloaded capacity that must be maintained in order to meet ~~r~~Regulation ~~r~~Requirements;

(g) Issuing shut-down instructions; and

(h) Specifying the voltage level and reactive reserve each Market Participant must maintain.

* * *

7. TRANSMISSION PRICING.

* * *

7.2.1.2 Zone-Based Approach. The ISO will use a Zone-based approach to manage Congestion. A Zone is a portion of the ISO Controlled Grid within which Congestion is expected to occur infrequently or have relatively low Congestion Management costs. Inter-Zonal Interfaces consist of transmission facilities that are expected to have relatively high Congestion Management costs~~, as described in Section 7.2.7.1~~. For these interfaces, allocation of usage based on the value placed on these interfaces by the Scheduling Coordinators will increase efficient use of the ISO Controlled Grid.

7.2.1.3 Types of Congestion. Congestion that occurs on Inter-Zonal Interfaces is referred to as "Inter-Zonal Congestion." Congestion that occurs due to transmission system ~~c~~Constraints within a Zone is referred to as "Intra-Zonal Congestion."

* * *

7.2.1.5 Elimination of Real-~~-~~Time Inter-Zonal Congestion. In its management of Inter-Zonal Congestion in real time, the ISO will issue Dispatch Instructions as necessary to relieve Inter-Zonal Congestion by Dispatching Generation or Demand, as necessary, based on the Energy Bids in accordance with Dispatch Protocol Section 8.3.

* * *

7.2.4.1.4 The ISO shall use Energy Bids from Generating Units and from other resources in the ISO's real-~~-~~time system operation, for increasing resources' output for Intra-Zonal Congestion Management to decrement Generation in order to accommodate Overgeneration conditions, including Reliability Must-Run Generation which the ISO requests under Reliability Must-Run Contracts.

* * *

7.2.4.2.7 The ISO may impose additional restrictions and bidding activity rules on the form of Adjustment Bids, the updating of Adjustment Bids, and the Scheduling Coordinator that may submit Adjustment Bids in connection with ~~i~~inter-Scheduling Coordinator ~~T~~trades, as needed, to ensure that the ISO's computational algorithms can operate reliably and produce efficient outcomes.

* * *

7.2.5.2.2 If Congestion would exist on one or more active Inter-Zonal Interfaces, then the ISO shall execute its Inter-Zonal Congestion Management algorithms to determine a set of tentative (in the Day-Ahead procedure) allocations of Inter-Zonal Interface rights and tentative (in the

Day-Ahead procedure) Usage Charges, where the Usage Charges will be calculated as the marginal values of the Congested Inter-Zonal Interfaces. The marginal value of a Congested Inter-Zonal Interface is calculated by the ISO's computer optimization algorithm to equal the total change in ~~r~~Redispatch costs (based on the Adjustment Bids) that would result if the interface's scheduling limit was increased by a small increment.

* * *

7.2.5.2.9~~8~~ The ISO will also publish information, once it is available, regarding tentative prices for the use of Inter-Zonal Interfaces, and Generation shift factors for the use of Inter-Zonal Interfaces, which indicate the relative effectiveness of Generation shifts in alleviating Congestion.

7.2.6 Intra-Zonal Congestion Management.

7.2.6.1 Decremental Bids. With regard to decremental bids, if Final Hour-Ahead Schedules cause Congestion on the Intra-Zonal interface, the ISO shall, after Dispatching available and effective Reliability Must-Run Units to manage the Congestion, apply the decremental reference prices determined by the independent entity that determines the reference prices for the Automatic Mitigation Procedure (AMP) as described in Appendix A to the Market Monitoring and Information Protocol. The ISO shall Dispatch Generating Units according to the decremental reference prices thus established, the resource's effectiveness on the Congestion, and other relevant factors such as Energy limitations, existing contractual restrictions, and Regulatory Must-Run or Regulatory Must-Take status, to alleviate the Congestion after Final Hour-Ahead Schedules are issued. Where the ISO must reduce a Generating Unit's output, the ISO shall Dispatch Generating Units according to the decremental reference prices and not according to Adjustment Bids or Supplemental Energy Bids to alleviate Intra-Zonal Congestion. No Generating Unit shall be Dispatched below its minimum operating level or above its maximum operating level. No Reliability Must-Run Unit shall be Dispatched below the operating level determined by the ISO as necessary to maintain reliability. If

Congestion still exists after all Generating Units are Dispatched to their minimum operating levels, the ISO shall instruct Generating Units to shut off in merit order based on their decremental reference prices at minimum load, beginning with the most expensive unit.

The ISO shall apply the decremental reference prices to thermal Generating Units and to non-thermal Generating Units.

If the ISO Dispatches System Resources or Dispatchable Loads to alleviate Intra-Zonal Congestion, the ISO shall Dispatch those resources in merit order according to the resource's Day-Ahead or Hour-Ahead Adjustment Bid or Imbalance Energy bid.

The ISO shall only ~~r~~Redispatch Regulatory Must-Take or Regulatory Must-Run Generation, Intermittent Resources, or Qualifying Facilities to manage Intra-Zonal Congestion after ~~r~~Redispatching all other available and effective generating resources, including Reliability Must-Run Units.

7.2.6.1.1 Decremental Bid Reference Levels. Decremental bid reference levels shall be determined for use in managing Intra-Zonal Congestion as set forth above in Section 7.2.6.1

(a) Determination. Decremental bid reference levels shall be determined by applying the following steps in order as needed:

1. Excluding proxy bids, mitigated bids, and bids used out of merit order for managing Intra-Zonal Congestion, the accepted decremental bid, or the lower of the mean or the median of a resource's accepted decremental bids if such a resource has more than one accepted decremental bid in competitive periods over the previous 90 days for peak and off-peak periods, adjusted for monthly changes in fuel prices using the proxy figure for natural gas prices posted on the ISO Home Page. Accepted and justified decremental bids below the applicable soft cap, as set forth in Section 28.1.3 of this Tariff, will be included in the calculation of reference prices;

2. A level determined in consultation with the Market Participant submitting the bid or bids at issue, provided such consultation has occurred prior to the occurrence of the conduct being examined by the ISO, and provided the Market Participant has provided sufficient data in accordance with specifications provided by the ISO or the independent entity responsible for determining reference prices;
3. 90 percent of the unit's default Energy Bid determined monthly as set forth in Section 5.11.5 (based on the incremental heat rate submitted to the ISO, adjusted for gas prices, and the variable O&M cost on file with the ISO, or the default O&M cost of $6/MWh);
4. 90 percent of the mean of the economic Market Clearing Prices for the units' relevant location (~~z~~Zone or node commensurate with the pricing granularity in effect) during the lowest-priced 25 percent of the hours that the unit was dispatched or scheduled over the previous 90 days for peak and off-peak periods, adjusted for changes in fuel prices; or
5. If sufficient data do not exist to calculate a reference level on the basis of the first, second, or fourth methods and the third method is not applicable or an attempt to determine a reference level in consultation with a Market Participant has not been successful, the ISO shall determine a reference level on the basis of:
    i. the ISO's estimated costs of an electric facility, taking into account available operating costs data, opportunity cost, and appropriate input from the Market Participant, and the best information available to the ISO; or
    ii. an appropriate average of competitive bids of one or more similar electric Facilities.

(b) Monotonicity.

The decremental bid reference levels ($/MWh bid price) for the different bid segments of each resource shall be made monotonically non-decreasing by the ISO by proceeding from the highest MW bid segment moving through each lower MW bid segment. The reference level of each succeeding bid segment, moving from right to left in order of decreasing operating level, shall be the lower of the reference level of the preceding bid segment or the reference level determined according to paragraph (a) above.

* * *

7.2.6.2 Incremental Bids. With regard to incremental bids, except as provided in Sections 5.2, 7.2.6.1 and 11.2.4.2, the ISO will perform Intra-Zonal Congestion Management in real time using available Imbalance Energy bids, based on their effectiveness and in merit order, to minimize the cost of alleviating Congestion. In the event no Imbalance Energy bids are available, the ISO will exercise its authority to direct the ~~r~~Redispatch of resources as allowed under the Tariff, including Section ~~2.4.2 and~~ 2.4.4.

* * *

7.3.1.3.3 Upon the ISO Operations Date, and until such time as the ISO determines otherwise, the ceiling price for the default Usage Charge will be set at $250/MWh; the floor price for the default Usage Charge will be set at $30/MWh; and the pre-set adder that is to be applied in accordance with ~~s~~Section 7.3.1.3.2 will be set at $0/MWh.

* * *

7.3.1.5.2 If a Scheduling Coordinator fails to provide the scheduled flows in a counter direction, it must reimburse the ISO for the ISO's costs of buying or selling Imbalance Energy in each of the Zones affected by the non-provided scheduled flows in a counter direction, at the ISO's Zonal Imbalance Energy prices. That is, for any Scheduling Coordinator that does not produce, in real time, the amount of Energy scheduled in the Day-Ahead Market or Hour-Ahead

Market will be deemed to have purchased/sold the amount of Energy under/over produced in the real-time imbalance market at the real-time price.

* * *

7.3.1.7 ISO Debit of Net Usage Charge Revenues. If, after the issuance of Final Day-Ahead Schedules by the ISO, (a) Participating TOs instruct the ISO to reduce interface limits based on operating conditions or (b) an unscheduled transmission ~~o~~Outage occurs and as a result of either of those events, Congestion is increased and Available Transfer Capacity is decreased in the Inter-Zonal Interface in the Hour-Ahead Market, the ISO shall: (1) charge each Participating TO and Project Sponsor(s) as provided in Section 3.2.7.3, and FTR Holder with an amount equal to its proportionate share, based on its financial entitlement to Usage Charges in the Day-Ahead Market in accordance with Section 7.3.1.6, of the product of (i) the Usage Charge in the Day-Ahead Market and (ii) the reduction in Available Transfer Capacity across the Inter-Zonal Interface in the direction of the Congestion (such amount due to the Participating TOs to be debited by them in turn from their Transmission Revenue Balancing Accounts or, for those Participating TOs that do not have such accounts, to their Transmission Revenue Requirements); (2) charge each Scheduling Coordinator with its proportionate share, based on Schedules in the Day-Ahead Market across the Inter-Zonal Interface in the direction of the Congestion, of the difference between the amount charged to Participating TOs and Project Sponsors as provided in Section 3.2.7.3, and FTR Holders under clause (1) and the Usage Charges in the Hour-Ahead Market associated with the reduced Available Transfer Capacity across the Congested Inter-Zonal Interface; and (3) credit each Scheduling Coordinator whose Schedule in the Hour-Ahead Market for the transfer of Energy across the Congested Inter-Zonal Interface was adjusted due to the reduction in Available Transfer Capacity an amount equal to the product of the adjustment (in MW) and the Usage Charge in the Hour-Ahead Market (in$/MW).

The ISO will issue a notice to Scheduling Coordinators of the operating hour, and extent, for which the derate will apply in the relevant Hour-Ahead Markets. The timing and form of such notices shall be set forth in ISO procedures.

7.3.2 Grid Operations Charge for Intra-Zonal Congestion.

Scheduling Coordinators whose resources are rRedispatched by the ISO, in accordance with Intra-Zonal Congestion Management as set forth in Section 7.2.6, will be paid or charged as set forth in Settlements and Billing Protocol Appendix B. The net rRedispatch cost will be recovered for each Settlement Period through the Grid Operations Charge, which shall be paid to the ISO by all Scheduling Coordinators in proportion to their metered Demands within the Zone with Intra-Zonal Congestion, and scheduled exports from the Zone with Intra-Zonal Congestion to a neighboring Control Area, provided that, with respect to Demands within an MSS in the Zone and scheduled exports from the MSS to a neighboring Control Area, a Scheduling Coordinator shall be required to pay Grid Operations Charges only with respect to Intra-Zonal Congestion, if any, that occurs on an interconnection between the MSS and the ISO Controlled Grid, and with respect to Intra-Zonal Congestion that occurs within the MSS, to the extent the Congestion is not relieved by the MSS Operator.

7.4 Transmission Losses.

7.4.1 Obligation to Provide for Transmission Losses.

Each Scheduling Coordinator shall ensure that it schedules sufficient Generation to meet both its Demand and Transmission Losses responsibilities as determined in accordance with this Section 7.4. Scheduling Coordinators for Generators, System Units and System Resources are responsible for their respective proportion of tTransmission lLosses as determined in accordance with Section 7.4.2. For each Final Hour-Ahead Schedule, each Scheduling Coordinator representing Generators or System Units shall elect through the flag described in SBP Section 2.1.1 to either: 1) generate sufficient additional energy to meet its respective

tTransmission lLosses or 2) be financially responsible for its respective transmission loss obligation based on the Imbalance Energy procured on its behalf by the ISO. In the ISO Imbalance Energy Mmarket, all Scheduling Coordinators for Generators, System Units, and System Resources must be financially responsible for all respective tTransmission lLosses associated with their respective Imbalance Energy Dispatch Instructions in Rreal Ttime, based on the Imbalance Energy procured on their behalf by the ISO. A Scheduling Coordinator for an MSS Operator that has elected to follow Load will be responsible for its transmission loss obligation pursuant to Sections 23.12.1 and 23.16.4.

* * *

7.4.2.1.2 The ISO will calculate the Ex Post Generation Meter Multiplier for each electrical bus at which one or more Generating Units may supply Energy to the ISO Controlled Grid. The Ex Post Generation Meter Multipliers shall be determined utilizing the Power Flow Model based upon the ISO's total Demand for the ISO Controlled Grid and Demand and Generation patterns throughout the ISO Controlled Grid. The ISO's total Demand shall be determined using real-time power flow data based on a state-estimation result.

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8. GRID MANAGEMENT CHARGE.

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8.3.1 Core Reliability Services Charge.

The Core Reliability Services Charge for a Scheduling Coordinator is calculated using the Scheduling Coordinator's metered non-coincident peak hourly dDemand during the month (in megawatts). The rate for the Core Reliability Services Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total of the forecasted metered non-coincident peak hourly

dDemand for all months during the year, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.2 Energy Transmission Services Net Energy Charge.

The Energy Transmission Services Net Energy Charge for each Scheduling Coordinator is calculated using that Scheduling Coordinator's Metered Control Area Load (in megawatt-hours). The rate for the Energy Transmission Services Net Energy Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted Metered Control Area Load, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.3 Energy Transmission Services Uninstructed Deviations Charge.

The Energy Transmission Services Uninstructed Deviations Charge for each Scheduling Coordinator is calculated using that Scheduling Coordinator's net uninstructed deviations by sSettlement iInterval. The rate for the Energy Transmission Services Uninstructed Deviations Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted net uninstructed deviations by sSettlement iInterval according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

* * *

8.3.6 Market Usage Charge.

The Market Usage Charge for each Scheduling Coordinator is calculated using the absolute value of the Scheduling Coordinator's market purchases and sales of Ancillary Services, Supplemental Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with uninstructed deviations being netted by sSettlement iInterval). The rate for the Market

Usage Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted number of market purchases and sales, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

* * *

9. FIRM TRANSMISSION RIGHTS

9.1 General

9.1.1 Commencing in 2000, on the effective date established by the ISO Governing Board, the ISO shall make FTRs available in the amounts determined in accordance with Section 9.3, with the rights and other characteristics described in Sections 9.2, 9.6, 9.7 and 9.8, and through the processes described in Section 9.4. Proceeds of the ISO's auction of FTRs shall be distributed as described in Section 9.5. The owners of FTRs shall be entitled to share in Usage Charge revenues associated with Inter-Zonal Congestion in accordance with Section 9.6, and to scheduling priority in the event of ~~c~~Congestion in the Day-Ahead Market, as described in Section 9.7. For the purpose of Section 9, the term "Zone" shall be construed to mean both "Zone" and "Scheduling Point."

* * *

9.3 Maximum Number of Firm Transmission Rights

9.3.1 On each Inter-Zonal Interface and direction combination for which FTRs are issued, the ISO shall issue a number of FTRs that is less than or equal to the difference between:

(i) The WSECC approved path rating of the interface in the direction from the originating Zone to the receiving Zone or, if the interface has not received a WSECC approved rating, a rating determined by a methodology that is consistent with the WSECC's rating methodology; and

(ii) The portion of the transfer capability of the interface available for transmission scheduling under Existing Contracts as Existing Rights.

and ensures the ISO's ability to honor all of its FTRs simultaneously under normal operating conditions.

* * *

9.4.2.3 In each round of the auction following the first round, the ISO will increase the price at which FTRs are made available in each FTR ~~m~~Market in accordance with the formula posted in accordance with Section 9.4.2.1(iii), or in accordance with any adjustment to the coefficients in that formula that is announced by the ISO to the FTR Bidders at least one round in advance of the round for which the adjustment is made. Price increases need not be uniform for all FTR Markets.

In the case of an FTR Market in which the demand for FTRs in the preceding round is less than or equal to the quantity of FTRs being made available, the price shall not increase and the auction for that FTR Market shall close. After each round of the auction, the ISO shall announce simultaneously to all FTR Bidders the total quantity of FTRs for which valid bids were submitted in each FTR Market, whether the auction for each FTR Market is closed, and, the revised prices for the following round of the auctions that remain open. Within the timeframe set by the ISO in accordance with Section 9.4.2.1(vi), each FTR Bidder may submit bids for the quantity of FTRs it desires to purchase in each FTR Market at the revised price, provided that an FTR Bidder may not bid for a number of FTRs in an FTR Market that exceeds the total number of FTRs in that FTR Market for which that entity submitted bids in the preceding round of the auction. The ISO

shall conduct subsequent rounds of the auction in each FTR Market until the demand for FTRs in the FTR Market is less than or equal to the quantity of FTRs being made available, at which point the auction shall be closed in that FTR Market.

9.4.2.4 Subject to Section 9.4.2.5, each successful FTR Bidder shall receive a number of FTRs in each FTR ~~m~~Market equal to the number of FTRs for which it bid in the last round of the auction for that FTR Market.

* * *

9.4.2.7 Each FTR Bidder shall pay the ISO an amount equal to the sum, for all FTR Markets, of the products of the FTR price in each FTR Market (determined in accordance with Section 9.4.2.6) and the total quantity of FTRs awarded to that FTR Bidder in that FTR Market (determined in accordance with Section 9.4.2.4 or Section 9.4.2.5, as applicable). ~~-~~FTR Bidders shall pay the amount determined in accordance with the foregoing sentence within ten (10) ~~b~~Business ~~d~~Days of receiving an invoice from the ISO by making payment to the ISO Clearing Account in accordance with Section 11.10. If the FTR Bidder fails to make timely payment of the full amount due, the ISO may enforce any guarantee, letter of credit or other credit support provided by the defaulting FTR Bidder in accordance with Section 9.4~~.~~2.6~~7~~ and, if the ISO is required to institute proceedings to collect any unpaid amount, the defaulting FTR Bidder shall pay Interest on the unpaid amount for the period from the Payment Date until the date on which payment is remitted to the ISO Clearing Account.

* * *

9.6.2 In addition, an FTR ~~h~~Holder shall be entitled to receive a portion of the additional net Usage Charges related to Inter-Zonal Congestion calculated by the ISO in the Hour-Ahead Market and collected by the ISO with respect to the Inter-Zonal Interface and direction combination for which the FTR was defined. The FTR Holder shall receive a portion of the net

Usage Charges in the Hour-Ahead Market proportionate to the share of the Usage Charges it received in the Day-Ahead Market in accordance with Section 9.6.1.

9.6.3 When the Day-Ahead scheduling capability of an Inter-Zonal Interface and direction is less than its scheduling capacity, determined in accordance with Section 9.3, prior to the Day-Ahead Market, the entitlements of FTR Holders associated with that FTR Market to Usage Charge revenues shall not be reduced until and unless the entitlements of Participating TOs associated with that FTR Market to Usage Charge revenues in accordance with Section 7.3.1.6 have been reduced to zero. In that event, the financial entitlements associated with the corresponding FTRs shall be multiplied by a factor equal to the amount of scheduling capability available to holders of the remaining FTRs divided by the number of such FTRs. When the Day-Ahead scheduling capability of an Inter-Zonal Interface and direction is greater than its scheduling capacity, determined in accordance with Section 9.3, prior to the Day-Ahead Market, the entitlements of FTR Holders associated with that FTR ~~m~~Market to Usage Charge revenues shall not be increased.

9.6.4 When the ~~c~~Congestion Usage Charges calculated and collected by the ISO from the Hour-Ahead Market with respect to transfers across an Inter-Zonal Interface in a particular direction result in a net obligation to the ISO, in the circumstances described in Section 7.3.1.7, the provisions of this Section 9.6 shall continue to apply, and FTR Holders shall be required to pay the ISO these amounts.

9.6.5 The ISO will calculate the ~~c~~Congestion Usage Charge revenues to be credited or debited to the account of each FTR Holder on an hourly basis. Such calculation will identify the Inter-Zonal Interface and direction to which each credit or debit applies.

9.7 Scheduling Priority of FTR Holders

9.7.1 FTRs will not affect the ISO's dispatch and operation of the ISO Controlled Grid except that each FTR Holder will have a priority, as described in this Section 9.7, for the scheduling of Energy in the Day-Ahead Market when an Inter-Zonal Interface experiences Inter-Zonal Congestion in the direction for which its FTR is defined. Any FTRs not used in Preferred Schedules in the Day-Ahead Market for any hour have no scheduling priority for that hour in the ~~t~~Trading ~~d~~Day. FTR Holders shall have no scheduling priority in the Hour-Ahead Market or in real~~-~~time operations.

9.7.2 When Inter-Zonal Congestion is experienced or projected to be experienced in the Day-Ahead Market, the ISO shall first attempt to relieve the Inter-Zonal Congestion using Adjustment Bids submitted by Scheduling Coordinators in accordance with Section 7.2.4.

9.7.2.1 If the ISO is unable to relieve the Day-Ahead Inter-Zonal Congestion using Adjustment Bids, then the ISO will allocate Day-Ahead inter-zonal transmission capacity first to ~~s~~Schedules of Market Participants that are using Existing Contract rights that have higher scheduling priority than Converted Rights capacity and second to Market Participants who hold FTRs and have indicated to the ISO that they wish to exercise their scheduling priority option. The ISO will allocate any remaining transmission capacity to remaining Market Participants' ~~s~~Schedules pro rata.

9.7.3 When the scheduling capability of an Inter-Zonal Interface is less than or greater than its normal scheduling capability prior to the Day-Ahead Market, as described in Section 9.6.3, the priority scheduling rights of FTR Holders, as described in Section 9.7.2, shall remain constant (in MWs) to the extent that the total scheduling rights of FTR Holders do not exceed the total Interface scheduling capability of the associated Inter-Zonal Interface after adjustments have been made for transmission capacity allocated to Existing Contract rights that have higher scheduling priority than Converted Rights. If the total Interface scheduling capability, adjusted for transmission capacity allocated to Existing Contract rights that have higher scheduling priority

than Converted Rights, is less than the total of all scheduling capability represented by FTR ~~h~~Holders who have chosen to exercise the FTR scheduling priority option, scheduling capability shall be allocated to FTR Holders pro rata.

* * *

9.8 Assignment of Firm Transmission Rights

9.8.1 An FTR may be assigned, sold, or otherwise transferred by the FTR Holder to any entity eligible to be an FTR Holder in full MW increments, either for the entire term of the FTR or for any portion of that term providing, however, that any such transfer shall be in full hour increments that correspond to the FTR issued to the FTR Holder. All FTRs that are so assigned, sold, or otherwise transferred by the FTR Holder are subject to the terms and conditions for FTRs approved by FERC and set forth in the ISO Tariff. Both the FTR Holder of record and the entity to which the FTRs have been transferred shall register the transfer of the FTR with the ISO by notifying the ISO through the form specified for that purpose by the ISO, and within the number of ~~b~~Business ~~d~~Days following the transfer published by the ISO on the ISO Home Page and WEnet but no later than such time as the ISO shall specify before the deadline applicable to scheduling Energy in the Day-Ahead Market, of (i) the identity of the FTR Holder of record; (ii) the identity of the entity to which the FTRs have been transferred; (iii) the quantity and identification numbers of the FTRs being transferred; (iv) the portion of the term of the FTR for which they are transferred; (v) the price at which the FTRs are being transferred; and (vi) whether the transfer of FTRs is subject to any conditions. The entity to which the FTRs have been transferred must also notify the ISO of all entities with which the transferee is affiliated that are FTR Holders or Market Participants as defined in the ISO Tariff, pursuant to Section 9.2.7. After the ISO receives such notices, the transferee shall be considered the FTR Holder of record with respect to the portion of the term of the FTR that is transferred. In order to use the Scheduling Priority of an FTR, pursuant to ~~s~~Section 9.7, an FTR must be registered with the ISO.

9.8.2 The ISO shall publish on the ISO Home Page such information concerning the concentration of ownership of FTRs in each FTR Market as determined by the ISO Governing Board ~~of Governors~~ from time to time.

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10. METERING.

10.1 Applicability.

Unless otherwise expressly stated to the contrary, the requirements set forth in these Sections 10.1 to 10.5 inclusive apply only to ISO Metered Entities.

* * *

10.2.1 Duty to Provide Meter Data.

ISO Metered Entities shall ensure that Meter Data from their meters directly connected to the ISO Controlled Grid or at interconnections thereto, including interconnections between utility Service Areas which have separate UFE calculations, is made available to the ISO revenue ~~m~~Meter ~~d~~Data acquisition and processing system in accordance with the requirements of these Sections 10.1 to 10.5 and the ISO metering protocols. Pursuant to this obligation, the ISO shall establish revenue metering protocols for such ISO Metered Entities.

10.2.2 Duty to Install and Maintain Meters.

The ISO may require ISO Metered Entities to install, at their cost, additional meters and relevant metering system components, including real-time metering, at ISO specified Meter Points or other locations as deemed necessary by the ISO, in addition to those connected to or existing on the ISO Controlled Grid at the ISO Operations Date, including requiring the metering of transmission interfaces connecting Zones. In directing the addition of meters and metering system components that would impose increased costs on an ISO Metered Entity, the ISO shall give due consideration to whether the expected benefits of such equipment are sufficient to justify such increased costs. ISO Metered Entities, at their cost, shall install and maintain, or cause to be installed and maintained, metering equipment and associated communication devices at ISO designated Meter Points to meet the requirements of this Section 10 and the ISO metering protocols. Nothing in this Section 10 shall preclude ISO Metered Entities from installing additional meters, instrument transformers and associated communications facilities at their own cost.

* * *

10.2.4 Certification of Meters.

Each ISO Metered Entity that makes Meter Data available to the ISO -shall ensure that metering facilities used to produce such Meter Data have been certified by the ISO as meeting the requirements of these Sections 10.1 to 10.5 and the ISO metering protocols. Certification of the relevant metering facilities shall only be provided upon the production of such evidence as the ISO may reasonably require to demonstrate that the facilities in question have been documented, inspected and successfully tested by the ISO or an ISO Authorized Inspector for conformance to the standards and accuracy requirements referred to in Appendix J and the ISO metering protocols. Meters of End-Use ISO Metered Entities in place as of the ISO Operations Date are deemed to be certified as in compliance with Appendix J and such End-Users shall not be required to enter into meter service agreements with the ISO provided that their Scheduling Coordinators have entered into a meter service agreement with the ISO. ISO certification pursuant to this Section 10.2.4 shall not relieve the ISO Metered Entity from the obligation to ensure that its metering facilities continue to remain in compliance with the requirements of these Sections 10.1 to 10.5 and the ISO metering protocols.

10.2.5 Metering Communications.

The ISO's revenue meter data acquisition and processing system shall collect and process Meter Data made available by ISO Metered Entities pursuant to meter service agreements. Meter Data for ISO Metered Entities shall be made available to the ISO's revenue meter data acquisition and processing system either directly by the ISO Metered Entity or via a central data server which collects Meter Data for various ISO Metered Entities provided that the central data server does not aggregate or adjust that Meter Data. Meter Data on the ISO's revenue meter data acquisition and processing system may be accessed from the system's database by the ISO Settlement system, other ISO application programs, relevant Scheduling Coordinators and

other authorized users as identified in the relevant meter service agreement ("other authorized users") subject to the ISO being satisfied that access by such authorized users will not adversely effect the security of data held by the ISO. ISO Metered Entities shall ensure that their metering facilities are compatible with the ISO revenue meter data acquisition and processing system for these purposes. The ISO may, at its discretion, exempt an ISO Metered Entity from the requirement to make Meter Data directly available to the ISO's revenue meter data acquisition and processing system, for example, where the installation of communication links is unnecessary, impracticable or uneconomic. The ISO shall maintain the revenue meter data acquisition and processing system and remedy any faults occurring in such system. ISO Metered Entities shall ensure compliance with the metering protocols to be established by the ISO pursuant to Section 10.2.1. Scheduling Coordinators and other authorized users requiring Settlement Quality Meter Data for ISO Metered Entities they schedule or supply may obtain such data by polling the revenue meter data acquisition and processing system via WEnet in accordance with the ISO metering protocol. Scheduling Coordinators and other authorized users shall not poll the ISO revenue meter data acquisition and processing system for any other purpose, unless specifically authorized in their meter service agreement. If any Scheduling Coordinator does not have the ability to poll the ISO's revenue meter data acquisition and processing system as at the ISO Operations Date, that Scheduling Coordinator shall have a period of up to 12 months from the ISO Operations Date in which to install the necessary equipment to enable it to poll directly the ISO revenue meter data acquisition and processing system. During the period in which a Scheduling Coordinator is unable to poll directly the ISO revenue meter data acquisition and processing system, that Scheduling Coordinator will be responsible for providing the ISO with Settlement Quality Meter Data in accordance with the ISO metering protocols.

* * *

10.3.2 Security and Meter Data Validation Procedures.

The meter service agreement for each ISO Metered Entity and the ISO metering protocols shall set out, in such detail as the ISO may deem necessary, the Meter Data security and validation procedures that the ISO shall apply to the Meter Data made available by each ISO Metered Entity. The ISO may base the security and validation procedures on historical data or an appropriate alternative data source. The ISO shall correct or replace or cause to be corrected or replaced inaccurate or missing data. The procedure may include data correction and substitution algorithms which shall estimate, substitute and flag such inaccurate or missing data. Any necessary correction or replacement shall be approved by the ISO prior to the data being sent to the ISO Settlement system. Security and validation measures for existing Tie-Point Meters shall be consistent with existing arrangements with the operators in adjacent Control Areas. Any additional measures or changes to the existing arrangements shall only be implemented upon mutual agreement of the ISO and the operator in the adjacent Control Area.

* * *

10.6.7.7 Scheduling Coordinator Metered Entity Certification, Testing and Audit.

Subject to any Local Regulatory Authority requirements, the ISO reserves the right to inspect, test and otherwise audit the entire metering systems of the Scheduling Coordinator Metered Entity connected to the ISO Controlled Grid, from the ~~m~~Meter ~~d~~Data server to the metering system(s), and such systems shall be subject to ISO audits and tests. However, only the ~~m~~Meter ~~d~~Data server supplying the ISO is subject to ISO certification requirements.

~~(10)~~The Scheduling Coordinator or its designated representative shall provide the ISO with all such information, assistance and cooperation the ISO reasonably requires in order to conduct such inspections, tests and audits.

11.2 Calculations of Settlements.

The ISO shall calculate, account for and settle the following charges in accordanc-e with this ISO Tariff.

* * *

11.2.4 Imbalance Energy.

The ISO shall calculate, Dispatch and account for Imbalance Energy for each Dispatch Interval and settle Imbalance Energy in the Real Time Market for each Settlement Interval for the relevant Zone or Scheduling Point within the ISO Controlled Grid. Imbalance Energy is the difference between the Metered Quantity and the Energy that corresponds to the ~~f~~Final Hour-Ahead Schedule. Instructed Imbalance Energy is the portion of Imbalance Energy that is produced or consumed due to Dispatch ~~i~~Instructions. The Instructed Imbalance Energy will be calculated based on all Dispatch ~~i~~Instructions taking into account applicable ramp rates and time delays. All Dispatch ~~i~~Instructions shall be deemed delivered. The remaining Imbalance Energy constitutes Uninstructed Imbalance Energy, and will be calculated based on the difference between the Metered Quantity and the Generator's Dispatched Operating Point.

* * *

11.2.4.1.1.1 Bid Cost Recovery for Generating Units, System Units and Curtailable ~~Lo~~Demand.

The ISO shall determine, for each Trading Day, for each Generating Unit, System Unit and Curtailable ~~Lo~~Demand, Dispatched in the Real-Time Market pursuant to Section 2.5.22, whether there exists a surplus or deficit in that resource's recovery of its Energy Bid costs, that are less than or equal to the Maximum Bid Level, through Instructed Imbalance Energy credits, as set forth in Section 11.2.4.1.1. This determination of market revenue surplus or deficit shall be calculated as the difference between: 1) the Instructed Imbalance Energy payment as based

on the relevant Resource-Specific Settlement Interval Ex Post Price and 2) the resource's Energy Bid cost for each Settlement Interval. Bid cost recovery payment will be based on Settlement Intervals in which the resource did not: 1) recover its Energy Bid costs, and 2) generated or consumed an amount of Energy equal to its schedule, any Dispatch Instructions and its applicable Tolerance Band. The Tolerance Band requirement will not apply to Must-Offer Generators that produce a quantity of Energy above minimum load due to an ISO Dispatch Instruction. These Settlement Intervals will be netted against all Settlement Intervals in which the Instructed Imbalance Energy payments to the resource exceeded its Energy Bid costs. The resulting total bid cost recovery payment is then divided equally amongst the same Settlement Intervals to yield a per-Settlement Interval bid cost recovery payment. For non-must offer resources, this per-Settlement Interval bid cost recovery payment shall then be paid to each Settlement Interval in which the resource generated or consumed an amount of Energy equal to its schedule, any Dispatch Instructions and its applicable Tolerance Band. For must-offer resources, this per-Settlement Interval bid cost recovery payment shall be made in each interval the unit was instructed by the ISO to operate above its minimum load, or returning to its minimum load from a prior ISO instruction. Payments for un-recovered bid costs for portions of Energy associated with bids above the Maximum Bid Level will not be netted with other surpluses or deficits and are subject to recall if the such bids above have not been adequately justified pursuant to Section 28.1.2. Energy Bid cost recovery associated with Residual Energy as provided for in Section 2.5.22.6.4 shall be based on the Energy Bids for the previous or next operating hour, whichever the case may be, upon which the Dispatch Instruction was based.

11.2.4.1.1.2 Bid Cost Recovery for System Resources

The ISO shall determine, for each Settlement Period, for each System Resource submitting bids in the Real-Time Market pursuant to Section 2.5.22, whether there exists a surplus or deficit in that resource's recovery of its Energy Bid costs. This determination of market revenue surplus

or deficit shall be calculated as the difference between: 1) the Instructed Imbalance Energy payment as based on the simple average of the relevant Dispatch Interval Ex Post Prices for each Settlement Period and 2) the resource's Energy Bid cost for each Settlement Period. An uplift payment will be made as necessary for each Settlement Period to assure that the System Resource recovers its Energy Bid costs for the quantity of Energy delivered. Payments for un-recovered bid costs for portions of Energy associated with bids above the Maximum Bid Level are subject to recall if such bids have not been adequately justified pursuant to Section 28.1.2.

11.2.4.1.2 Penalties for Uninstructed Imbalance Energy

The ISO shall charge Scheduling Coordinators Uninstructed Deviation Penalties for Uninstructed Imbalance Energy resulting from resource deviations outside a Tolerance Band from their Dispatch Operating Point, for dispatched resources, or their ~~f~~Final Hour-Ahead Schedule otherwise. The Dispatch Operating Point will take into account the expected ~~r~~Ramping of a resource as it moves to a new Hour-Ahead Schedule at the top of each hour and as it responds to Dispatch Instructions. The Uninstructed Deviation Penalty will be applied as follows:

a) The Uninstructed Deviation Penalty for negative Uninstructed Imbalance Energy will be calculated and assessed in each Settlement Interval. The Uninstructed Deviation Penalty for positive Uninstructed Imbalance Energy will be calculated and assessed in each Settlement Interval in which the ISO has not declared a ~~S~~staged System Emergency;

b) The Uninstructed Deviation Penalty will apply to ~~P~~pre-Dispatched bids from non-dynamically scheduled System Resources identified, when such a ~~P~~pre-Dispatch Instruction is issued more than 40 minutes prior to the relevant Operating Hour, subject to the following conditions: i) The Uninstructed Deviation Penalty will only apply to the ~~P~~pre-Dispatched amount of the bid that is declined or not delivered, ii) the Uninstructed Deviation Penalty will not apply to a portion of a ~~P~~pre-Dispatched bid that is

subsequently not delivered at the direction of a Control Area, including the ISO, due to a curtailment of transmission capability or to prevent curtailment of native firm load occurring subsequent to issuing the ~~P~~pre-Dispatch Instruction, iii) the Uninstructed Deviation Penalty will not apply to uninstructed energy resulting from declining subsequent intra-hour Dispatch Instructions. Dynamically scheduled System Resources, to the extent they deviate from their Final Hour-Ahead Schedule plus any real-time Dispatch Instructions, will be subject to the Uninstructed Deviation Penalty;

c) The Uninstructed Deviation Penalty will not apply to Load or Curtailable Demand;

d) [Not Used]

e) The Uninstructed Deviation Penalty will not apply to Regulatory Must-Run Generation or Participating Intermittent Resources that meet the scheduling obligations established in the Eligible Intermittent Resources Protocol. No other applicable charges will be affected by this exemption. The Uninstructed Deviation Penalty also will not apply to Qualifying Facilities (QFs) that have not executed a Participating Generator Agreement (PGA), pending resolution of QF-PGA issues at FERC~~the Commission~~;

f) For the Scheduling Coordinator of an MSS that has elected to follow the MSS Load and associated ~~t~~Transmission ~~l~~Losses pursuant to Section 23.12, the ~~D~~deviation ~~P~~penalties in Sections 23.12.2.1 and 23.12.2.2 will apply. For the Scheduling Coordinator of an MSS that has not elected to follow the MSS Load, the Uninstructed Deviation Penalties in this Section 11.2.4.1.2 will apply;

g) The Uninstructed Deviation Penalty will apply to Generating Units providing Regulation and dynamically scheduled System Resources providing Regulation to the extent that ~~U~~uninstructed ~~D~~deviations from such resources exceed each resource's actual Regulation range plus the applicable Tolerance Band. Resources providing Regulation and generating within their relevant Regulating range (or outside their relevant

Regulating range as a direct result of ISO control or instruction) will be deemed to have zero deviations for purposes of the Uninstructed Deviation Penalty.

h) The Uninstructed Deviation Penalty will be calculated and assessed for each resource individually, except that as specified in this Section, ~~U~~uninstructed ~~D~~deviations from individual resources may be aggregated. Uninstructed ~~D~~deviations can be aggre~~ga~~gavated for resources that: 1) are represented by the same Scheduling Coordinator, 2) are connected to the same ISO Controlled Grid bus and voltage level, and 3) are not Reliability Must Run Condition 2 resources. The ISO will consider, on a case-by-case basis, requests to aggregate ~~U~~uninstructed ~~D~~deviations amongst resources represented by the same Scheduling Coordinator based on an ISO review of impact on the ISO Controlled Grid. The ISO may temporarily suspend any aggregation as needed to ensure reliability. The applicable Pmax of aggregated groups of resources will exclude units that are not operating;

i) [Not Used]

j) [Not Used]

k) The Uninstructed Deviation Penalty will not apply when the Zonal Settlement Interval Ex Post Price is negative or zero;

l) The Uninstructed Deviation Penalty for positive Uninstructed Imbalance Energy will be the amount of the Uninstructed Imbalance Energy in excess of the Tolerance Band multiplied by a price equal to 100% of the corresponding Zonal Settlement Interval Ex Post Price. The net effect of the Uninstructed Deviation Penalty and the Settlement for positive Uninstructed Imbalance Energy beyond the Tolerance Band will be that the ISO will not pay for such Energy;

m) The Uninstructed Deviation Penalty for negative Uninstructed Imbalance Energy will be the amount of the Uninstructed Imbalance Energy in excess of the Tolerance Band multiplied by a price equal to 50% of the corresponding Zonal Settlement Interval Ex Post Price;

n) The Uninstructed Deviation Penalty will not apply to deviations from Energy delivered as part of a scheduled test so long as the test has been scheduled by the Scheduling Coordinator with the ISO or the ISO has initiated the test for the purposes of validating unit performance;

o) The Uninstructed Deviation Penalty shall apply to any excess Energy delivered from or any shortfall of Energy not delivered from an ~~O~~out ~~of~~ ~~M~~market (OOM) transaction involving a Generating Unit or a System Unit once the ISO and the supplier have agreed upon the time of, duration of, and the amount of Energy to be delivered in the OOM transaction. The Uninstructed Deviation Penalty shall apply to firm OOM transactions with System Resources to the extent the System Resource fails to deliver the agreed-to Energy or over-delivers the agreed-to Energy if that over- or under-delivery was due to action taken by or not taken by the System Resource and not the result of action taken by a ~~e~~Control ~~a~~Area operator due to a curtailment of firm transmission capability or to prevent curtailment of native firm load occurring subsequent to issuing the ~~P~~pre-Dispatch Instruction;

p) Generating Units with Uninstructed Imbalance Energy will be exempted from the Uninstructed Deviation Penalty if the Generating Unit was physically incapable of delivering the expected Energy, provided that the Generating Unit had notified the ISO within 30 minutes of the onset of an event that prevents the resource from performing its obligations. A Generating Unit must notify ISO operations staff of its reasons for failing to deliver the expected Energy in accordance with Section 2.3.3.9.5~~2~~ and must provide

information to the ISO that verifies the reason the resource failed to comply with the Dispatch instruction within 48 hours of the operating hour in which the instruction is issued;

q) Adjustments to any Generating Unit, Curtailable Demand and System Resource Final Hour-Ahead Schedules made in accordance with the terms of Existing ~~Transmission~~ Contracts shall not be subject to Uninstructed Deviation Penalties.

r) Any changes made to Schedules prior to the ISO issuing Final Hour-Ahead Schedules shall not be subject to Uninstructed Deviation Penalties.

s) Uninstructed Deviation Penalties shall not be charged to any deviation from a Dispatch Instruction that does not comply with the requirements set forth in the Dispatch Protocol.

t) Amounts collected as Uninstructed Deviation Penalties shall first be assigned to reduce the portion of above-MCP costs that would otherwise be assigned pro rata to all Scheduling Coordinators in that Settlement Interval pursuant to Section 11.2.4.2.2. Any remaining portion of amounts collected as Uninstructed Deviation Penalties after satisfying these sequential commitments shall be treated in accordance with SABP 6.5.2.

u) Condition 2 RMR Units shall be exempt from Uninstructed Deviation Penalties.

11.2.4.2 Payment Options for ISO Dispatch Orders

With respect to all resources which have not bid into the Imbalance Energy or Ancillary Services markets but which have been dispatched by the ISO to avoid an intervention in market operations, to prevent or relieve a System Emergency, or to satisfy a locational requirement, the ISO shall calculate, account for and, if applicable, settle deviations from the Final Schedule submitted on behalf of each such resource, with the relevant Scheduling Coordinator for each Settlement Period for each such resource by application of either of the following payment

options described below. For resources subject to a Reliability Must-Run Contract, the ISO will dispatch such resources according to the terms of the RMR Contract. In circumstances where an RMR Unit would be used to resolve Intra-Zonal Congestion and there are no such RMR Units available, a resource may be called upon and paid under this Section to resolve the Intra-Zonal Congestion.

By December 31 of each year for the following calendar year, each Scheduling Coordinator for a resource shall select one of the following payment options for each resource it schedules:

(a) the Uninstructed Imbalance Energy ~~C~~charge price as calculated in accordance with Section 2.5.23.2.2~~11.2.4.1~~ (i.e., using the Hourly Ex Post Price) or

(b) a calculated price:

(i) for decremental dispatch orders that is an Energy payment to the ISO that is equal to the Market Clearing Price for the relevant Settlement Period for the applicable Energy market less verifiable daily gas imbalance charges, if any, that are solely attributable to the ISO's ~~d~~Dispatch ~~i~~Instruction and that the Scheduling Coordinator or Generator was not able to eliminate or reduce despite the application of best efforts, if the Scheduling Coordinator provides the resource's daily gas imbalance charges to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched; and

(ii) for incremental dispatch orders is the sum of: 1) a capacity payment equal to the average Day-Ahead Market prices for Spinning Reserve and Non-Spinning Reserve for the three (3) most recent similar days for the same Settlement Period for which the resource is dispatched; 2) an Energy payment equal to the average calculated using the ~~PX Day-~~

~~Ahead, PX Hour-Ahead and~~ ISO Real-_Time Market Energy prices for the three (3) most recent similar days for the same Settlement Period for which the resource is dispatched; 3) such resource's verifiable ~~s~~Start-~~u~~Up ~~f~~Fuel ~~c~~Costs, if the start-up was solely attributable to the ISO's ~~d~~Dispatch ~~i~~Instruction and if the Scheduling Coordinator provides the resource's ~~s~~Start-~~u~~Up ~~f~~Fuel ~~c~~Costs to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched; and 4) verifiable daily gas imbalance charges, if any, that are solely attributable to the ISO's ~~d~~Dispatch ~~i~~Instruction and that the Scheduling Coordinator or Generator was not able to eliminate or reduce despite the application of best efforts, if the Scheduling Coordinator provides the resource's daily gas imbalance charges to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched. References to "similar days" in this Section refer to Business Days when the resource is dispatched on a Business Day and otherwise to days that are not Business Days.

To the extent a Scheduling Coordinator does not specify a payment option, the ISO will apply the payment provisions of the payment option described in Section 11.2.4.2(a)~~Section 11.2.4.1~~.

11.2.4.2.1 Allocation of Costs Resulting From Dispatch Instructions

Pursuant to Section 11.2.4.1, the ISO may, at its discretion, Dispatch any Participating Generator, Participating Load and dispatchable System Resource that has not bid into the Imbalance Energy or Ancillary Services markets, to avoid an intervention in market operations or to prevent or relieve a System Emergency. Such Dispatch may result from, among other things, planned and unplanned transmission facility ~~o~~Outages; bid insufficiency in the Ancillary Services

and ~~R~~real-~~T~~time Energy markets; and location-specific requirements of the ISO. The cost associated with each Dispatch instruction is broken into two components:

a) the portion of the Energy payment at or below the Market Clearing Price ("MCP") for the Settlement Interval, and

b) the portion of the Energy payment above the MCP, if any, for the Settlement Interval.

For each Settlement Interval, costs above the MCP incurred by the ISO for such Dispatch instructions necessary as a result of a transmission facility ~~o~~Outage or in order to satisfy a location-specific requirement in that Settlement Interval shall be payable to the ISO by the Participating Transmission Owner in whose Service Area the transmission facility is located or the location-specific requirement arose. The costs incurred by the ISO for such Dispatch instructions for reasons other than for a transmission facility ~~o~~Outage or a location-specific requirement will be recovered in the same way as for Instructed Imbalance ~~e~~Energy.

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11.2.4.2.2.1 Allocation of Bid Costs Above the Maximum Bid Level

For each Settlement Interval, costs that are both above the MCP and above the Maximum Bid Level, incurred by the ISO as a result of Instructed Imbalance Energy and Dispatch instructions for reasons other than for a transmission facility ~~o~~Outage or ~~-~~a location-specific requirement shall be charged to Scheduling Coordinators as follows in a three-step process. First, each Scheduling Coordinator's charge shall be the lesser of:

(a) the pro rata share of the total costs that are both above the MCP and above the Maximum Bid Level based upon the ratio of each Scheduling Coordinator's Net Negative Uninstructed Deviations to the total ~~S~~system Net Negative Uninstructed Deviations; or

(b) the amount obtained by multiplying the Scheduling Coordinator's Net Negative Uninstructed Deviation for each Settlement Interval and a weighted average price. The

weighted average price is equal to the total costs that are both above the MCP and above the Maximum Bid Level divided by the MWh delivered as a result of ISO instructions with a cost component above the MCP.

Second, any remaining unallocated costs shall be reduced pursuant to Section 11.2.4.1.2.

Third, any remaining unallocated costs shall be allocated amongst all Scheduling Coordinators in that Settlement Interval pro rata based on their metered Demand, including ~~E~~exports.

A Scheduling Coordinator shall be exempt from the first allocation step of costs that are both above the MCP and above the Maximum Bid Level in a Settlement Interval if the Scheduling Coordinator has sufficient incremental Energy bids from physically available resources in the Imbalance Energy market to cover its ~~n~~Net ~~n~~Negative Uninstructed Deviation in the given Settlement Interval and the prices of such Energy bids do not exceed the applicable Maximum Bid Level as set forth in Section 28.1.2 of this Tariff.

* * *

11.2.4.5.1 Uninstructed Energy and Transmission Losses by Participating Intermittent Resources

Uninstructed Imbalance Energy associated with deviations by a Participating Intermittent Resource and ~~t~~Transmission ~~l~~Losses shall be settled as provided in this Section 11.2.4.5.1 for every Settlement Period in which such Participating Intermittent Resource meets the scheduling requirements established in the ISO Protocols. In each Settlement Period such requirements are met, the Participating Intermittent Resource shall be exempt from the charges (payments) for Uninstructed Imbalance Energy. Instead, the net Uninstructed Imbalance Energy in each Settlement Interval, together with the transmission loss obligation calculated in accordance with Section 7.4.1.1, shall be assigned to a deviation account specific to each Participating Intermittent Resource. The net balance in each deviation account at the end of each calendar month shall be paid (or charged) to the Scheduling Coordinator for the associated Participating

Intermittent Resource at the average price specified in Section 2.5.23.2.3 of the ISO Tariff. If the above-referenced scheduling requirements for Participating Intermittent Resources are not met, then charges (payments) for Uninstructed Imbalance Energy during such Settlement Periods shall be determined in accordance with Section 11.2.4.1.

* * *

11.2.4.5.3 Allocation of Costs From Participating Intermittent Resources

The charges (payments) for Uninstructed Imbalance Energy that would have been calculated if the Settlement Interval deviations by each Participating Intermittent Resource were priced at the appropriate ~~Settlement~~Dispatch Interval Ex Post Price ~~specified in Section 2.5.23.2.1~~ shall be assigned to a monthly balancing account for all Participating Intermittent Resources in the ISO Control Area. The balance in such account at the end of each month shall be netted against the aggregate payments (charges) by Scheduling Coordinators on behalf of Participating Intermittent Resources pursuant to Section 11.2.4.5.1. The resulting balance, together with the adjustments to charges in each Settlement Interval or Settlement Period pursuant to Section 11.2.4.5.2 shall be assigned to each Scheduling Coordinator in the same proportion that such Scheduling Coordinator's aggregate Net Negative Uninstructed Deviations in that month bears to the aggregate Net Negative Uninstructed Deviations for all Scheduling Coordinators in the Control Area in that month.

* * *

11.3.2 Payment for the charges referred to in Section 11.1.6 of the ISO Tariff (except for the charges payable under long-term contracts) for each Trading Day in each calendar month shall be made five (5) Business Days after issuance of the Preliminary Settlement Statement for the last day of the relevant calendar month. Payment for adjustments will be made five (5) Business Days after issuance of the Final Settlement Statement for the last day of the relevant month. Payments for FERC Annual Charges will be made in accordance with Section 7.5 of this ISO Tariff.

* * *

11.5 Calculation in the Event of Lack of Meter Data for the Balancing of Market Accounts.

Settlements shall not be cleared for final processing until the accounting trial balance is zero. In order to publish a Settlement Statement, the ISO may use estimated, disputed or calculated Meter Data-. When actual verified Meter Data is available and all of the disputes raised by Scheduling Coordinators during the validation process described in Section 11.7 of this ISO Tariff have been determined, the ISO shall recalculate the amounts payable and receivable by the affected Scheduling Coordinators or by all Scheduling Coordinators, if applicable, as soon as reasonably practical and shall show any required adjustments as a debit or credit in the next Settlement Statement.

* * *

11.6.3 Settlement ~~r~~Re-runs and post final adjustments.

The ISO is authorized to perform Settlement Statement ~~r~~Re-runs following approval of the ISO Governing Board. A request to perform a Settlement Statement ~~r~~Re-run may be made at any time by a Scheduling Coordinator by notice in writing to the ISO Governing Board. The ISO Governing Board shall, in considering whether to approve a request for a Settlement Statement ~~r~~Re-run, determine in its reasonable discretion, whether there is good cause to justify the performance of a Settlement Statement ~~r~~Re-run.

11.6.3.1 If a Settlement Statement ~~r~~Re-run is ordered by the ISO Governing Board, the ISO shall arrange to have the Settlement Statement ~~r~~Re-run carried out as soon as is reasonably practicable following the ISO Governing Board's order, subject to the availability of staff and computer time, compatible software, appropriate data and other resources.

11.6.3.2 The ISO Governing Board may order the cost of a Settlement Statement ~~r~~Re-run to be borne by the Scheduling Coordinator requesting it, unless the Settlement Statement ~~r~~Re-run was needed due to a clerical oversight or error on the part of the ISO staff.

11.6.3.3 Where a Settlement Statement ~~r~~Re-run indicates that the accounts of Scheduling Coordinators should be debited or credited to reflect alterations to Settlements previously made under this ISO Tariff, for those Scheduling Coordinators affected by the statement re-run, the ISO shall reflect the amounts to be debited or credited in the next Preliminary Settlement Statements that it issues following the Settlement Statement ~~r~~Re-run to which the provisions of this Section 11 apply.

* * *

11.21.1 Required Capabilities.

The ISO shall ensure that the Settlement process shall contain, at a minimum, the following data gathering and storage capabilities:

(a) the accurate, time-sequenced, end-to-end traceability of the Settlements process so that Scheduling Coordinators and Participating TOs can fully verify their Settlement Statements;

(b) the ability to specify and accept data that is specifically needed for audit trail requirements; and

(c) the archiving of ~~m~~Meter ~~d~~Data, Settlement ~~R~~runs and other information used to prepare Settlement Statements to be consistent with the time frame required to re-run the Settlement process by state laws and the rules of the Local Regulatory Authority.

* * *

13.2.4 Mediation.

The mediator and representatives of the disputing parties, with authority to settle the dispute, shall within fourteen (14) days after the mediator's date of appointment schedule a date to mediate the dispute. Matters discussed during the mediation shall be confidential and shall not be referred to in any subsequent proceeding. With the consent of all disputing parties, a resolution may include referring the dispute directly to a technical body (such as a WSECC technical advisory panel) for resolution or an advisory opinion, or referring the dispute directly to FERC. The ISO shall publish notice of the referral of the dispute in the ISO newsletter or WEnet, and any other method adopted by the ISO ADR Committee.

* * *

20.3.1 ISO

The ISO shall maintain the confidentiality of all of the documents, data and information provided to it by any Market Participant that are treated as confidential or commercially sensitive under Section 20.3.2; provided, however, that the ISO need not keep confidential: (1) information that is explicitly subject to data exchange through WEenet pursuant to Section 6 of this ISO Tariff; (2) information that the ISO or the Market Participant providing the information is required to disclose pursuant to this ISO Tariff, or applicable regulatory requirements (provided that the ISO shall comply with any applicable limits on such disclosure); or (3) information that becomes available to the public on a non-confidential basis (other than as a result of the ISO's breach of this ISO Tariff).

20.3.2 Confidential Information

The following information provided to the ISO by Scheduling Coordinators shall be treated by the ISO as confidential:

(a) individual bids for Supplemental Energy;

(b) individual Adjustment Bids for Congestion Management which are not designated by the Scheduling Coordinator as available;

(c) individual bids for Ancillary Services;

(d) transactions between Scheduling Coordinators;

(e) individual Generator Outage programs unless a Generator makes a change to its Generator Outage program which causes Congestion in the short-_term (i.e. one month or less), in which case, the ISO may publish the identity of that Generator.

* * *

21.1 Temporary Simplification Relating to GMM Loss Factors.

Notwithstanding any other provision in the ISO Tariff, including the ISO Protocols, in determining whether a Schedule is a Balanced Schedule, no allowance shall be made for Transmission Losses (i.e. the Generation Meter Multiplier shall be set at 1.0) for ~~the PX and~~ all ~~other~~ Scheduling Coordinators.

* * *

21.2.1 Pursuant to Subsections 21.3.1 and 21.3.2, the Chief Executive Officer of the ISO shall give notice to all Scheduling Coordinators~~, except the PX,~~ that such Scheduling Coordinators shall use forecasted Generation Meter Multipliers, as published by the ISO, in their Schedules. Such notice shall be given only after the Chief Executive Officer determines that the ISO is capable of accepting ~~s~~Schedules using the forecasted Generation Meter Multipliers without adversely affecting operations or reliability.

21.2.2 [Not used]~~Pursuant to Subsections 21.3.1 and 21.3.2, the Chief Executive Officer of the ISO shall give notice to the PX that the PX shall use forecasted Generation Meter Multipliers, as~~

~~published by the ISO, in its Schedules, upon mutual agreement by the Chief Executive Officers of the ISO and PX that the PX is capable of providing schedules pursuant to this Tariff using the ISO's forecasted Generation Meter Multipliers without adversely affecting operations or reliability.~~

23 METEREDetered SUBSYSTEMSubsystems

***

23.4.6 be responsible for Intra-Zonal Congestion Management and transmission line Outages within or at the boundary of the MSS, and all associated costs and not responsible for Intra-Zonal Congestion Management elsewhere in the zZone except to the extent that a Scheduling Coordinator is delivering Energy to or from the MSS.

***

23.5.2 The Scheduling Coordinator for the MSS will designate, in discrete quantities and with prices for both Ancillary Services and Energy: (1) Schedules in Day-Ahead and Hour-Ahead Energy markets (including sSchedules for internal Generation and internal DemandLoad within the MSS), (2) bids or self-provided Schedules for Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve capacity and associated bid Energy, (3) Adjustment Bids, (4) Supplemental Energy bids, or (5) any feasible combination thereof.

***

23.12.2 Under the circumstances described in Section 23.12.1, the Scheduling Coordinator for an MSS Operator shall pay amounts based on a price that is the effective weighted average eEx pPost pPrice applicable to the MSS's Scheduling Coordinator for the billing interval (the "Deviation Price"). The revenue received from these payments will be used as an off-set to the ISO's Grid Management Charge.

The payments due from a Scheduling Coordinator will be calculated as follows:

***

23.12.3.3 Only GMC associated with uninstructed deviations (the Ancillary Services and Real-Time Energy Operations Charge (ASREO)) will be treated on a net basis. GMC for Control Area Services (CAS) will be charged based on Gross Load and exports out of the MSS. The Scheduling Coordinator for the MSS Operator will be assessed the GMC Congestion Management Charge (CONG) in accordance with Section 8.3. Ancillary Service bids accepted by the ISO and Instructed Energy will be assessed the GMC ASREO.

***

23.13.1 System Planning Studies and Forecasts.

The ISO, the MSS Operator and Participating TOs shall share information such as projected Load growth and system expansions necessary to conduct necessary system planning studies to the extent that these may impact the operation of the ISO Control Area. Each MSS Operator shall provide to the ISO annually its ten-year forecasts of Demand growth, internal Generation, and expansion of or replacement for any transmission facilities that are part of the MSS that will or may significantly affect any point of interconnection between the MSS and the ISO Controlled Grid. Such forecasts shall be provided on the date that UDCs are required to submit forecasts to the ISO under Section 4.8.1. Each MSS Operator or each Scheduling Coordinator for an MSS Operator shall also submit weekly and monthly peak Demand fForecasts in accordance with the ISO's protocols.

***

23.13.3.5 _____Forms. The ISO shall, in consultation with MSS Operators, jointly develop and, as necessary, revise, any necessary forms and procedures for collection, study, treatment, and transmittal of system data, information, reports and forecasts.

***

23.16.4 The Scheduling Coordinator for the MSS shall be responsible for ~~t~~Transmission ~~l~~Losses, in accordance with the ISO Tariff, only within the MSS, at any points of interconnection between the MSS and the ISO Controlled Grid, and for the delivery of Energy to the MSS or from the MSS, provided the MSS Operator fulfills its obligation to provide for ~~t~~Transmission ~~l~~Losses on the transmission facilities forming part of the MSS. A Generation Meter Multiplier shall be assigned to the Generating Units on the MSS at the Points of Interconnection for use of the ISO Controlled Grid. That GMM shall be 1.0 for all Generating Units within the MSS that are located at or behind a Point of Interconnection, to the extent that the Load at the Point of Interconnection for that portion of the MSS exceeds the amount of Generation produced by the Generating Units connected to that portion of the MSS, except that a GMM shall be calculated by the ISO for Energy produced pursuant to a Dispatch instruction from the ISO.

***

28.1.3 Negative Decremental Energy Bids

Negative decremental Energy bids into the ISO Markets less than -$30/MWh (minus thirty dollars per MWh) shall not be eligible to set any ~~m~~Market ~~c~~Clearing ~~p~~Price and, if Dispatched, shall be paid as bid. If the ISO Dispatches a bid below -$30/MWh, the supplier must submit a detailed breakdown of the component costs justifying the bid to the ISO and to the Federal Energy Regulatory Commission no later

than seven (7) days after the end of the month in which the bid was submitted. The ISO will treat such information as confidential and will apply the procedures in Section 20.3.4 of this ISO Tariff with regard to requests for disclosure of such information. The ISO shall pay suppliers for amounts in excess of $-30/MWh after those amounts have been justified.

***

30.3 Disconnection of Non-Y2K Compliant Systems and Processes

In order to protect and maintain the integrity of the ISO's systems and processes, the ISO shall have the authority to immediately disconnect the systems or processes of any Scheduling Coordinator or other entity that is believed by the ISO to be passing Y2K related erroneous data; i.e., data from systems and processes that do not meet the Section 30.1 standards for Y2K Compliance. The ISO will immediately notify the disconnected Scheduling Coordinator or other entity of the reason for the action taken by the ISO. The ISO shall permit such Scheduling Coordinator or other entity to reestablish interfaces with the ISO after receiving and approving documented test results showing that the disconnected systems or processes are Y2K Compliant and would not otherwise adversely affect the ISO's systems and processes. The ISO will review and approve or reject documented test results within two (2) ~~b~~Business ~~d~~Days of their receipt. The ISO will reconnect the entity within one (1) ~~b~~Business ~~d~~Day of the ISO's approval.

ISO TARIFF APPENDIX A

Master Definitions Supplement

* * *

~~**Actual Imbalance**~~	~~A deviation between scheduled Generation and metered Generation at each UDC/ISO Controlled Grid boundary or at each Participating Generator's delivery point or a deviation between scheduled Load and metered Load at each UDC/ISO Controlled Grid boundary or ISO Control Area boundary.~~
Adjustment Bid	A bid in the form of a curve defined by (i) the minimum MW output to which a Scheduling Coordinator will permit a resource (Generating Unit or Dispatchable Load) included in its Schedule or, in the case of an ~~i~~inter-Scheduling Coordinator ~~T~~trade, included in its Schedule or the Schedule of another Scheduling Coordinator, to be redispatched by the ISO; (ii) the maximum MW output to which a Scheduling Coordinator will permit the resource included in its Schedule or, in the case of an ~~i~~inter-Scheduling Coordinator ~~T~~trade, included in its Schedule or the Schedule of another Scheduling Coordinator, to be redispatched by the ISO; (iii) up to a specified number of MW values in between; (iv) a preferred MW operating point; and (v) for the ranges between each of the MW values greater than the preferred operating point, corresponding prices (in $/MWh) for which the Scheduling Coordinator is willing to increase the output of the resource and sell Energy from that resource to the ISO (or, in the case of a Dispatchable Load, decrease the Demand); and (vi) for the ranges between each of the MW

values less than the preferred operating point, corresponding prices (in $/MWh) for which the Scheduling Coordinator is willing to decrease the output of the resource and purchase Energy from the ISO at the resource's location (or, in the case of a Dispatchable Load, increase the Demand). This data for an Adjustment Bid must result in a monotonically increasing curve.

* * *

~~Aggregate Final Accepted Schedules~~
Alert Notice

~~ISO approved aggregated Final Schedules.~~
A Notice issued by the ISO when the operating requirements of the ISO Controlled Grid are marginal because of Demand exceeding forecast, loss of major Generation, or loss of transmission capacity that has curtailed imports into the ISO Control Area, or if the Hour-Ahead Market is short on scheduled Energy and Ancillary Services for the ISO Control Area.

* * *

Applicable Reliability Criteria

The reliability standards established by NERC, W~~S~~ECC, and Local Reliability Criteria as amended from time to time, including any requirements of the NRC.

* * *

Approved Credit Rating

With respect to whether security must be posted for payment of the Grid Management Charge:

(a) A short-term taxable commercial paper debt rating of not less than any one of the following: (i) A1 by Standard and Poor's Corporation; ~~(ii) D1 by Duff & Phelps Credit Rating Agency;~~ (iii) F1 by Fitch Ratings~~IBCA Incorporated~~; or (iii~~v~~) P1 by Moody's Investors Service. This rating shall be an issuer, or counterpart rating, without the benefit of credit enhancement.

(b) A short-term tax exempt commercial paper debt rating of not less than any one of the following: (i~~l~~) A1 by Standard and Poor's Corporation; (ii) V1 by Fitch ~~IBCA Incorporated~~Ratings; or (iii) VMIG1 by Moody's Investors Service. This rating shall be an issuer, or counterparty rating, without the benefit of credit enhancement.

With respect to whether security must be posted for payment of all charges other than the Grid Management Charge:

(c) A short-term tax exempt commercial paper debt rating of not less than any one of the following: (i) A2 by Standard and Poor's Corporation; ~~(ii) D2 by Duff & Phelps Credit Rating Agency;~~ (iii) F2 by Fitch ~~IBCA Incorporated~~Ratings; or (iii~~v~~) P2 by Moody's Investors Service. This rating shall be an issuer, or counterparty rating, without the benefit of credit enhancement.

(d) A short-term tax exempt commercial paper debt rating of not less than any one of the following: (i) A2 by Standard and Poor's Corporation; (ii) V2 by Fitch ~~IBCA Incorporated~~Rati ngs; or (iii) VMIG2 by Moody's Investors Service. This rating shall be

an issuer, or counterparty rating, without the benefit of credit enhancement.

(e) A long-term debt rating of not less than any one of the following: (i) A- by Standard and Poor's Corporation; ~~(ii) A- by Duff & Phelps Credit Rating Agency;~~ (iii) A- by Fitch ~~IBCA Incorporated~~Ratings; or (iii~~v~~) A3 by Moody's Investors Service. This rating shall be an issuer, or counterparty rating, without the benefit of credit enhancement.

With respect to whether security must be posted for payment of all charges:

(f) A federal agency shall be deemed to have an Approved Credit Rating if its financial obligations under the ISO Tariff are backed by the full faith and credit of the United States.

(g) A California state agency shall be deemed to have an Approved Credit Rating if its financial obligations under the ISO Tariff are backed by the full faith and credit of the State of California.

(h) Another credit rating approved by the ISO Governing Board ~~of Governors~~.

* * *

Automatic Mitigation Procedure (AMP)

The market power mitigation procedure described in MMIP ~~3~~Appendix A.

~~Availability Measure~~

~~An indication for measuring the performance of Transmission Owners in maintaining the reliability and availability of the~~

~~Transmission Owner's transmission system.~~

Available Transfer Capacity

For a given transmission path, the capacity rating in MW of the path established consistent with ISO and W~~S~~ECC transmission capacity rating guidelines, less any reserved uses applicable to the path.

* * *

Black Start Generator

A Participating Generator in its capacity as party to an Interim Black Start Agreement with the ISO for the provision of Black Start services, but shall exclude Participating Generators in their capacity as providers of Black Start services under their Reliability Must-Run Contracts.

* * *

~~**Conditional Energy Bids**~~

~~A Bid for Energy to serve Demand at or below a specified price.~~

* * *

Congestion Management Charge

The component of the Grid Management Charge that provides for the recovery of the ISO's costs of operating the Congestion Management process including, but not limited to, the management and operation of ~~i~~Inter-~~z~~Zonal ~~c~~Congestion markets, ~~a~~Adjustment ~~b~~Bids, taking Firm Transmission Rights and Existing Contracts into account, and determining the price for mitigating ~~c~~Congestion for flows on ~~c~~Congested paths. The formula for determining the Congestion Management Charge is

set forth in Appendix F, Schedule 1, Part A of this Tariff.~~.~~

* * *

~~**Cost Shifting**~~ ~~A transfer of costs from one group of customers to another or from one utility to another.~~

* * *

Curtailable Demand Demand from a Participating Load that can be curtailed at the direction of the ISO in the real~~-~~-time ~~d~~Dispatch of the ISO Controlled Grid. Scheduling Coordinators with Curtailable Demand may offer it to the ISO to meet Non-~~s~~Spinning Reserve or Replacement Reserve requirements.

* * *

Delivery Upgrade The transmission facilities, other than Direct Assignment Facilities and Reliability Upgrades, necessary to relieve ~~c~~Constraints on the ISO Controlled Grid and to ensure the delivery of energy from a New Facility to Load.

* * *

~~**Demand Bid**~~ ~~A bid into the PX indicating a quantity of Energy that an Eligible Customer wishes to purchase and, if relevant, the maximum price that the customer is prepared to pay for that Energy. This bid will only be accepted in the PX auction process if the Market~~

	~~Clearing Price is at or below the price of the Demand Bid. A Buyer may state, for each hour, a different price preference for each demand quantity in each location, i.e., the maximum price in each hour at which it is prepared to take a specified amount of Energy in the Day-Ahead Schedule. If a bid is submitted without a price, it is assumed that the bidder is prepared to pay the Market Clearing Price.~~
Demand Forecast	An estimate of Demand over a designated period of time.
~~**Demand Market Participant**~~	~~Any Eligible Customer on behalf of whom Demand and Ancillary Services are scheduled pursuant to the ISO Tariff.~~

* * *

~~**Direct Access Generation**~~	~~An Eligible Customer who is selling Energy or Ancillary Services through a Scheduling Coordinator.~~
Direct Assignment Facility	The transmission facilities necessary to physically and electrically interconnect a New Facility Operator to the ISO Controlled Grid at the point of interconnection.

* * *

Dispatchable Loads	Load which is the subject of an Adjustment Bid.

* * *

~~**Electric Capacity**~~	~~The continuous demand-carrying ability for which a Generating Unit, or other electrical apparatus is rated, either by the user or by the manufacturer.~~

* * *

~~**Eligible Regulatory Must-Run Generation**~~	~~Regulatory Must-Run Generation which (i) has been approved as Regulatory Must-Run Generation by a Local Regulatory Authority within California, and (ii) is owned or produced by a Participating TO or UDC which has provided direct access to its End-Use Customers and serves load in the ISO Control Area.~~
~~**Emergency Startup**~~	~~A startup order from the ISO delivered to a Generator in response to a System Emergency.~~

* * *

Emissions Costs	The mitigation fees, excluding capital costs, assessed against a ~~g~~Generating ~~u~~Unit by a state or federal agency, including air quality districts, for exceeding applicable NOx emissions limitations.
EMS (Energy Management System)	A computer control system used by electric utility dispatchers to monitor the real-time performance of the various elements of an electric system and to control Generation and transmission facilities.

* * *

~~**Energy Efficiency Services**~~	~~Services that are intended to assist End-Users in achieving savings in their use of Energy or increased efficiency in their use of Energy.~~

* * *

~~**Environmental Quality**~~	~~In relation to Energy, means Energy which involves production sources that reduce harm to the environment.~~
~~**Equipment Clearances**~~	~~The process by which the ISO grants authorization to another party to connect or disconnect electric equipment interconnected to the ISO Controlled Grid.~~
Ex Post GMM	GMM that is calculated utilizing the real-time Power Flow Model in accordance with Section 7.4.2.1.2.

* * *

Existing High Voltage Facility	A High Voltage Transmission Facility of a Participating TO that was placed in service on or before the Transition Date defined in ~~s~~Section 4.2 of Schedule 3 of Appendix F.

* * *

~~**Facility Thermal Ratings**~~	~~For all electric current carrying facilities, all applicable capacity or electric limits to be observed during normal, short-term emergencies, and long-term emergency operating conditions.~~

* * *

~~**Flexible Generation**~~	~~Generation that is capable of, and for which the Generator has agreed to, adjust operating levels in response to real time market price or ISO control signals.~~
Forbidden Operating Region	The operating region of a resource wherein the resource can not

operate in a stable manner and must ramp through at maximum ramp capacity.

* * *

Forward Scheduling Charge

The component of the Grid Management Charge that provides for the recovery of the ISO's costs, including, but not limited to the costs of providing the ability to Scheduling Coordinators to forward schedule Energy and Ancillary Services and the cost of processing accepted Ancillary Service bids. For purposes of the Forward Scheduling Charge, a schedule is represented by each Final Hour-Ahead Schedule with a value other than 0 MW submitted to the scheduling infrastructure/scheduling application system (import, export, Load, Generation, inter-Scheduling Coordinator trade, and Ancillary Services, including self-provided Ancillary Services) submitted to the ISO's scheduling infrastructure. The formula for determining the Forward Scheduling Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

FPA

Parts II and III of the Federal Power Act, 16 U.S.C. § 824 et seq., as they may be amended from time to time.

FTR (Firm Transmission Right)

A contractual right, subject to the terms and conditions of the ISO Tariff, that entitles the FTR Holder to receive, for each hour of the term of the FTR, a portion of the Usage Charges received by the ISO for transportation of energy from a specific originating Zone to a specific receiving Zone and, in the event of an uneconomic curtailment to manage Day-Ahead ~~c~~Congestion, to a Day-Ahead scheduling priority higher than that of a ~~s~~Schedule using

Converted Rights capacity that does not have an FTR.

* * *

~~**Generation Dispatch Constraints**~~ ~~Details of any mandatory Generating Unit commitment requirements (e.g., Must-Run Generation) or dispatch limits (minimum output or maximum output) that must be observed due to system operating constraints (e.g., thermal, voltage, or stability limits). These limits are in addition to limits that may be specified by Generators in their Energy or Ancillary Service bids to the ISO or PX.~~

~~**Generation Scheduling**~~ ~~The ISO's planned hourly pattern of Generation.~~

* * *

Good Utility Practice Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the~~.~~ desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be any one of a number of the optimum practices, methods, or acts to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region

* * *

Grid Operations Charge An ISO charge that recovers ~~r~~Redispatch costs incurred due to Intra-Zonal Congestion in each Zone. These charges will be paid to the ISO by the Scheduling Coordinators, in proportion to their metered Demand within, and metered exports from, the Zone to a neighboring Control Area.

* * *

~~**High Voltage Transmission Standby Serve**~~ ~~Service provided by a Participating TO which allows a Standby Service Customer to utilize the Participating TO's High Voltage Transmission Facilities as a backup to ensure that Energy may be reliably delivered to the Standby Service Customer in the event of an outage of a Generating Unit located on or near the customer's premise.~~

* * *

Hour-Ahead Market The forward market for Energy and Ancillary Services to be supplied during a particular Settlement Period that is conducted by the ISO~~, the PX~~ and other Scheduling Coordinators which opens after the ISO's acceptance of the Final Day-Ahead Schedule for the Trading Day in which the Settlement Period falls and closes with the ISO's acceptance of the Final Hour-Ahead Schedule.

* * *

Hourly Ex Post Price

The Energy-weighted average of the Dispatch Interval Ex Post Prices in each Zone during each ~~s~~Settlement ~~p~~Period. The Hourly Ex Post Price will vary between Zones when Congestion is present. This price is used in the Regulation Energy Payment Adjustment and in RMR settlements.

* * *

Imbalance Energy

Imbalance Energy is Energy from Regulation, Spinning and Non-~~s~~Spinning Reserves, or Replacement Reserve, or Energy from other Generating Units, System Units, System Resources, or Loads that are able to respond to the ISO's request for more or less Energy.

* * *

Instructed Imbalance Energy

The real-time change in Generation output or Demand (from dispatchable Generating Units, System Units, System Resources or Loads) which is instructed by the ISO to ensure that reliability of the ISO Control Area is maintained in accordance with Applicable Reliability Criteria. Sources of Imbalance Energy include Spinning and Non-Spinning Reserves, Replacement Reserve, and Energy from other dispatchable Generating Units, System Units, System Resources or Loads that are able to respond to the ISO's request for more or less Energy.

* * *

Inter-Scheduling Coordinator Energy ~~Coordinator~~ Trades	Energy transactions between Scheduling Coordinators.
	* * *
ISO Authorized Inspector	A person authorized by the ISO to certify, test, inspect and audit meters and ~~m~~Metering ~~f~~Facilities (as that term is defined in the ISO Metering Protocol) in accordance with the procedures established by the ISO pursuant to the ISO Protocols on metering.
	* * *
ISO Control Area Balancing Function	The real~~-~~-time Dispatch of Generation (and Curtailable Demand), directed by the ISO, to balance with actual Demand during the current operating hour to meet operating ~~r~~Reliability ~~c~~Criteria.
	* * *
ISO Memorandum Account	The memorandum account established by each California IOU pursuant to California Public Utilities~~y~~ Commission Order D. 96-08-038 date August 2, 1996 which records all ISO startup and development costs incurred by that California IOU.
ISO Metered Entity	a) any one of the following entities that is directly connected

to the ISO Controlled Grid:

i. a Generator other than a Generator that sells all of its Energy (excluding any Energy consumed by auxiliary load equipment electrically connected to that Generator at the same point) and Ancillary Services to the UDC in whose Service Area it is located;

ii. an Eligible Customer; or

iii. an End-User other than an End-User that purchases all of its Energy from the UDC in whose Service Area it is located; and

(b) any one of the following entities:

i. a Participating Generator;

ii. a Participating TO in relation to its Tie Point Meters with other TOs or Control Areas;

iii. a Participating Load;

iv. a Participating Intermittent Resource; or

v. a utility that requests that UFE for its ~~s~~Service ~~a~~Area be calculated separately, in relation to its meters at points of connection of its Service Area with the systems of other utilities.

* * *

ISP (Internet Service Provider)

An independent network service organization engaged by the ISO to establish, implement and operate W<u>E</u>enet.

* * *

Local Furnishing Participating TO	Any Tax-_Exempt Participating TO that owns facilities financed by Local Furnishing Bonds.
	* * *
Local Reliability Criteria	Reliability cCriteria established at the ISO Operations Date, unique to the transmission systems of each of the Participating TOs.
	* * *
Maintenance Outage	A period of time during which an Operator (i) takes its transmission facilities out of service for the purposes of carrying out routine planned maintenance, or for the purposes of new construction work or for work on de-energized and live transmission facilities (e.g., relay maintenance or insulator washing) and associated equipment; or (ii) limits the capability of or takes its Generating Unit or System Unit out of service for the purposes of carrying out routine planned maintenance, or for the purposes of new construction work.
~~**Marginal Generators**~~	~~Those Generating Units which, in an hour, are the sources of the last increments of Generation in the Preferred Schedule, excluding: (i) Must-Run Generation, (ii) Must-Take Generation, (iii) units scheduled to ramp at their maximum ramp rate throughout the hour, or (iv) units operating at minimum operating levels (when less costly Generation must be backed down).~~
~~**Marginal Loss Factor**~~	~~The marginal impact of a given Generating Unit's output on total system Transmission Losses.~~

* * *

Minimum Load Costs	The costs a ~~g~~Generating ~~u~~Unit incurs operating at minimum load.

* * *

MSS Operator	An entity that owns an MSS and has executed a MSS Agreement ~~described in Section 3.3.1~~.

* * *

~~**Municipal Tax Exempt TO**~~	~~A Transmission Owner that has issued Municipal Tax Exempt Debt with respect to any transmission facilities, or rights associated therewith, that it would be required to place under the ISO's Operational Control pursuant to the Transmission Control Agreement if it were a Participating TO.~~

* * *

Net FTR Revenue	The sum of: 1) the revenue received by the New Participating TO from the sale, auction, or other transfer of the FTRs provided to it pursuant to Section 9.4.3 FTR, or any substantively identical successor provision of the ISO Tariff; and 2) for each hour: a) the Usage Charge revenue received by the New Participating To associated with its Section 9.4.3 FTRs; minus b) Usage Charges that are: i) incurred by the Scheduling Coordinator for the New Participating TO under ISO Tariff Section 7.3.1.4, ii) associated with the New Participating TO's Section 9.4.3 FTRs, and iii) incurred by the New Participating TO for its energy transactions but not incurred as a result of the use of the transmission by a third-party and minus c) the charges paid by the New Participating TO pursuant to Section 7.3.1.7, to the extent such charges are incurred by the Scheduling Coordinator of the New Participating TO on ~~c~~Congested Inter-Zonal Interfaces that are associated with the Section 9.4.3 FTRs provided to the New Participating TO. The component of New FTR Revenue represented by item 2) immediately above shall not be less than zero for any hour.
Net Negative Uninstructed Deviation	The real~~-~~-time change in Generation or Demand associated with underscheduled Load (i.e., Load that appears unscheduled in real time) and overscheduled Generation (i.e., Generation that is scheduled in forward markets and does not appear in real time). Deviations are netted for each Settlement Interval, apply to a Scheduling Coordinator's entire portfolio, and include Load, Generation, ~~I~~imports and ~~E~~exports.

* * *

New High Voltage Facility	A High Voltage Transmission Facility of a Participating TO that is placed in service after the beginning of the transition period described in Section 4 of Schedule 3 of Appendix F, or a capital addition made and placed in service after the beginning of the transition period described in Section 4.~~1~~2 of Schedule 3 of Appendix F to an Existing High Voltage Facility.
New Participating TO	A Participating TO that is not an Original Participating TO.
Nomogram	A set of operating or scheduling rules which are used to ensure that simultaneous operating limits are respected, in order to meet NERC and W~~S~~ECC operating criteria.
~~**Non-ISO Transmission Facilities**~~	~~Transmission facilities, either inside or outside the State of California, over which the ISO does not exert Operational Control.~~

* * *

~~**Non-PX Generation**~~	~~Generation that is scheduled by a Scheduling Coordinator, other than the PX, and that supplies Loads through the use of transmission or distribution facilities owned by Participating TOs.~~
~~**Non-PX Load**~~	~~Load that is scheduled by a Scheduling Coordinator, other than the PX, and which is supplied through the use of transmission or distribution facilities owned by Participating TOs.~~
Non-Spinning Reserve	The portion of off-line generating capacity that is capable of being synchronized and ~~r~~Ramping to a specified load in ten minutes (or load that is capable of being interrupted in ten minutes) and that is capable of running (or being interrupted) for at least two hours.

* * *

Operating Reserve — The combination of Spinning and Non-Spinning Reserve required to meet WSECC and NERC requirements for reliable operation of the ISO Control Area.

* * *

OPF (Optimal Power Flow) — A computer optimization program which uses a set of control variables (which may include active power and/or reactive power controls) to determine a steady-state operating condition for the transmission grid for which a set of system operating eConstraints (which may include active power and/or reactive power constraints) are satisfied and an objective function (e.g. total cost or shift of schedules) is minimized.

* * *

Outage — Disconnection, separation or reduction in capacity, planned or forced, of one or more elements of an electric system.

* * *

PMS (Power Management System) — The ISO computer control system used to monitor the real-time performance of the various elements of the ISO Controlled Grid, control Generation, and perform operational power flow studies.

* * *

~~**PX (Power Exchange)**~~	~~The California Power Exchange Corporation, a state chartered, nonprofit corporation charged with providing a Day-Ahead forward market for Energy in accordance with the PX Tariff. The PX is a Scheduling Coordinator and is independent of both the ISO and all other Market Participants.~~
~~**PX Auction Activity Rules**~~	~~The rules by which bids submitted to and validated by the PX may be modified or withdrawn during a PX Energy market auction.~~
~~**Qualifying Hours**~~	~~Qualifying Hours has the meaning set forth in Section 5.12.7.1.1.2.5.~~

* * *

Real Time Market	The competitive generation market controlled and coordinated by the ISO for arranging real-time Imbalance Energy.

* * *

Regulation	The service provided either by Generating Units certified by the ISO as equipped and capable of responding to the ISO's direct digital control signals, or by System Resources that have been certified by the ISO as capable of delivering such service to the ISO Control Area, in an upward and downward direction to match, on a real-time basis, Demand and resources, consistent with established NERC and W~~S~~ECC operating criteria. Regulation is used to control the power output of electric

generators within a prescribed area in response to a change in system frequency, tieline loading, or the relation of these to each other so as to maintain the target system frequency and/or the established interchange with other areas within the predetermined limits. Regulation includes both the increase of output by a Generating Unit or System Resource ("Regulation Up") and the decrease in output by a Generating Unit or System Resource ("Regulation Down"). Regulation Up and Regulation Down are distinct capacity products, with separately stated requirements and Market Clearing Prices in each Settlement Period.

* * *

Reliability Must-Run Charge (RMR Charge)

The sum payable ~~each month~~ by a Responsible Utility to the ISO pursuant to Section 5.2.7 of the ISO Tariff for the costs, net of all applicable credits, incurred under the RMR Contract ~~of Reliability Must-Run Generation~~.

Reliability Must-Run Contract (RMR Contract)

A Must-Run Service Agreement between the owner of an RMR Unit and the ISO.~~rate schedule on file at FERC and in effect, or a contract between the ISO and a Generator, giving the ISO the right to call on the Generator to generate Energy or provide Ancillary Services from the Generating Unit as and when required to ensure the reliability of the ISO Controlled Grid, in return for certain payments.~~

Reliability Must-Run Generation (RMR Generation)

Generation that the ISO determines is required to be on line to meet Applicable Reliability Criteria requirements. This includes i) Generation constrained on line to meet NERC and WS~~E~~ECC

	reliability criteria for interconnected systems operation; ii) Generation needed to meet Load demand in constrained areas; and iii) Generation needed to be operated to provide voltage or security support of the ISO or a local area.
Reliability Must-Run Unit (RMR Unit)	A Generating Unit which is the subject of a Reliability Must-Run Contract.
Reliability Upgrade	The transmission facilities, other than Direct Assignment Facilities, beyond the first point of interconnection necessary to interconnect a New Facility safely and reliably to the ISO Controlled Grid, which would not have been necessary but for the interconnection of a New Facility, including network upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of a New Facility to the ISO Controlled Grid. Reliability Upgrades also include, consistent with WS~~S~~ECC practice, the facilities necessary to mitigate any adverse impact a New Facility's interconnection may have on a path's WS~~S~~ECC path rating.
REMnet	The Wide Area Network through which the ISO acquires ~~m~~Meter ~~d~~Data.
Replacement Reserve	Generating capacity that is dedicated to the ISO, capable of starting up if not already operating, being synchronized to the ISO Controlled Grid, and ~~r~~Ramping to a specified ~~Load point~~operating level within a sixty (60) minute period, the output of which can be continuously maintained for a two hour period. Also, Curtailable Demand that is capable of being curtailed within sixty minutes and that can remain curtailed for two hours.

* * *

Real-Time Dispatch ("RTD") Software	The security constrained optimal dispatch and ex post pricing software used by the ISO to determine which Ancillary Service and Supplementary Energy resources to Dispatch and to calculate the Ex Post Prices.
~~RTG (Regional Transmission Group)~~	~~A voluntary organization approved by FERC and composed of transmission owners, transmission users, and other entities, organized to efficiently coordinate the planning, expansion and use of transmission on a regional and inter-regional basis.~~

* * *

Schedule	A statement of (i) Demand, including quantity, duration and Take-Out Points and (ii) Generation, including quantity, duration, location of Generating Unit, and Transmission Losses; and (iii) Ancillary Services which will be self-provided, (if any) submitted by a Scheduling Coordinator to the ISO. "Schedule" includes Preferred Schedules, Suggested Adjusted Schedules, Final Schedules and Revised Schedules.

* * *

Scheduling Coordinator Metered Entity or SC Metered Entity	~~means a~~A Generator, Eligible Customer or End-User that is not an ISO Metered Entity.

* * *

Security Monitoring	The real-time assessment of the ISO Controlled Grid that is

conducted to ensure that the system is operating in a secure state, and in compliance with all Applicable Reliability Criteria.

* * *

Standard Ramp (-ing) A ramp calculated from two consecutive Final Hour Ahead Schedules that results in a straight trajectory between 10 minutes before the start of an operating hour to 10 minutes after the start of the operating hour

* * *

Start-Up Fuel Costs The cost of the fuel consumed by a particular ~~g~~Generating ~~u~~Unit from the time of first fire, the time of receipt of an ISO Dispatch instruction, or the time the unit was last synchronized to the grid, whichever is later, until the time the generating unit is synchronized or re-synchronized to the grid and producing Energy. Start-Up Fuel Costs are determined by multiplying the actual amount of fuel consumed by the proxy gas price as determined in accordance with Section 2.5.23.3.4 at the time the fuel is consumed.

Suggested Adjusted Schedule The output of the ISO's initial Congestion Management for each Scheduling Coordinator for the Day-Ahead Market ("Suggested Adjusted Day-Ahead Schedule") or for the Hour-Ahead Market ("Suggested Adjusted Hour-Ahead Schedule"). These Schedules will reflect ISO suggested adjustments to each Scheduling Coordinator's Preferred Schedule to resolve Inter-Zonal Congestion on the ISO Controlled Grid, based on the Adjustment

Bids submitted. These ~~s~~Schedules will be balanced with respect to Generation, Transmission Losses, Load, and trades between Scheduling Coordinators to resolve Inter-Zonal Congestion.

* * *

~~**Supply Market Participant**~~ ~~Any Generator on behalf of whom Generation and Ancillary Services are scheduled pursuant to the ISO Tariff.~~

System Emergency Conditions beyond the normal control of the ISO that affect the ability of the ISO Control Area to function normally including any abnormal system condition which requires immediate manual or automatic action to prevent loss of Load, equipment damage, or tripping of system elements which might result in cascading ~~o~~Outages or to restore system operation to meet the minimum operating reliability criteria.

* * *

Tax Exempt Participating TO A Participating TO that is the beneficiary of outstanding Tax-Exempt Debt issued to finance any electric facilities, or rights associated therewith, which are part of an integrated system including transmission facilities the Operational Control of which is transferred to the ISO pursuant to the TCA.

* * *

~~**Transfer Schedule**~~ ~~A Schedule for Energy that is delivered from one Scheduling Coordinator to another. Each Transfer Schedule must originate~~

~~and terminate completely within the ISO Control Area and may not involve more than two (one sending and one receiving) Scheduling Coordinators.~~

* * *

Uninstructed Imbalance Energy

The real-time change in Generation or Demand other than that instructed by the ISO or which the ISO Tariff provides will be paid at the price for Uninstructed Imbalance Energy.

* * *

Usage Charge

The amount of money, per 1 kW of scheduled flow, that the ISO charges a Scheduling Coordinator for use of a specific ~~c~~Congested Inter-Zonal Interface during a given hour.

* * *

Voltage Support

Services provided by Generating Units or other equipment such as shunt capacitors, static var compensators, or synchronous condensers that are required to maintain established grid voltage criteria. This service is required under normal or ~~s~~System ~~e~~Emergency conditions.

* * *

Wheeling Out

Except for Existing Rights exercised under an Existing Contract in accordance with Sections 2.4.3 and 2.4.4, the use of the ISO

	Controlled Grid for the transmission of Energy from a Generating Unit located within the ISO Controlled Grid to serve a Load located outside the transmission and ~~d~~Distribution ~~s~~System of a Participating TO.
Wheeling Through	Except for Existing Rights exercised under an Existing Contract in accordance with Sections 2.4.3 and 2.4.4, the use of the ISO Controlled Grid for the transmission of Energy from a resource located outside the ISO Controlled Grid to serve a Load located outside the transmission and ~~d~~Distribution ~~s~~System of a Participating TO.

* * *

WSCC (Western System Coordinating Council)	The Western Systems Coordinating Council or its successor, the WECC.
WECC (Western Electricity Coordinating Council)	The Western Electricity Coordinating Council or its successor.

* * *

ISO TARIFF APPENDIX C

ISO Scheduling Process

Day-aAhead Schedule Timeline

	Responsible Parties							
Line	**Time (Before or on)**	**ISO**	**~~Non-PX~~ SCs**	**~~PX~~**	**Must-Take and Reliability generation**	**UDC**	**~~PX Participants~~**	**Actions**
	Two days ahead							
0	6:00 PM	x						Publish forecasted transmission conditions (Generator Meter Multipliers, system load forecast (by Zones), estimated Ancillary Service requirements, scheduled transmission eOutages, lLoop fFlows, congestion, ATC, etc.)
	One day ahead							
1	5:00 AM	X						Notify Scheduling Coordinators of unit-specific Reliability Must Run requirements
2	6:00 AM	x						Update system load forecast and Ancillary Service requirements.
3			X					Notify ISO of price option for Reliability Must-Run Units for which notification was provided at 5:00 a.m.
4			x					Provide direct access load forecasts to the ISO.
5	6:30 AM	x						Provide net direct access load forecasts to UDCs.
6 [not used]	~~9:30 AM~~						~~x~~	~~Submit individual unit schedules, AS schedules/price bids and incs/decs for CM to the PX.~~
7 [not used]	~~9:45 AM~~			~~X~~				~~Validate individual units schedules, AS schedule/price bids and incs/decs.~~
8 [not used]	~~10:00 AM~~			~~X~~				~~Finalize MCP and linitial preferred schedules. Communicate MCP and resulting schedules to the PX participants.~~
9 [not used]				~~x~~				~~Finalize AS schedules (self-provision) or AS price bids. Communicate resulting AS schedules and/or price to PX participants.~~
10			x	~~x~~				Submit initial preferred energy schedules to the ISO.
11			x	~~x~~				Submit Ancillary Service bids and/or self-provided Ancillary Service schedules to the ISO.
12	10:00 AM	x						Validate all SC energy schedules, including RMR requirements, and bids; notify and resolve incorrect schedules and bids, if any.
13		x						Validate all SC Ancillary Service schedules and bids; notify and resolve incorrect Ancillary Service schedules and bids, If any.

14		x						Start the ~~i~~Inter-~~z~~Zonal ~~c~~Congestion ~~m~~Management evaluation process and Ancillary Services bid evaluation.
15	11:00 AM	x						If no ~~i~~Inter-~~z~~Zonal ~~c~~Congestion exists, go to line 27.
16		X						Complete advisory dispatch schedules and transmission prices if ~~i~~Inter-~~z~~Zonal ~~c~~Congestion exists.
17		x						Complete the advisory schedules and prices of each Ancillary Service.
18		x						Notify all SC if ~~i~~Inter-~~z~~Zonal ~~c~~Congestion exists. Publish advisory transmission prices.
19		x						Inform all SCs their advisory dispatch schedules if ~~i~~Inter-~~z~~Zonal ~~c~~Congestion exists.
20		x						Inform all SCs advisory AS schedules and prices if ~~i~~Inter-~~z~~Zonal ~~c~~Congestion exists.
21	11:05 PM		x	~~x~~			~~x~~	Start the process of developing revised schedules and price bids ~~(the PX may iterate with PX participants)~~.
22			x	~~x~~			~~x~~	Start the process of developing revised AS schedules and price ~~bids (the PX may iterate with PX participants)~~.
23	12:00 PM		x	~~x~~				Submit revised ~~p~~Preferred ~~s~~Schedules and price bids to the ISO.
24			x	~~x~~				Submit revised preferred AS schedules and price bids to the ISO.
25	12:00 PM	x						Validate all SC schedules and bids; notify and resolve incorrect schedules and bids, if any.
26		x						Validate all SC AS schedules and bids; notify and resolve incorrect schedules and bids, if any.
27		x						Start the ~~i~~Inter-~~z~~Zonal ~~c~~Congestion ~~m~~Management evaluation process and Ancillary Services bid evaluation.
28	1:00 PM	x						Complete final dispatch schedules and transmission prices.
29		x						Complete ~~f~~Final ~~s~~Schedules and prices of each Ancillary Service.
30	1:00 PM	x						Complete ~~f~~Final ~~s~~Schedules.
31	1:00 PM	x						Inform all SCs their final dispatch schedules.
32		x						Inform all SCs their final AS schedules and prices.
33		x						Publish transmission prices if ~~i~~Inter-~~z~~Zonal ~~c~~Congestion exists.
34		x						Calculate and communicate with SC the specific SC's ~~z~~Zonal prices if asked.
35 [not				~~x~~				~~Publish PX prices.~~

used]								
36 [not used]				~~x~~				~~Communicate the final generation and load schedules to PX participants.~~
37 [not used]				~~x~~				~~Communicate the final Ancillary Service schedules to PX participants.~~
38		x						Develop net schedules for each of the Control Area interfaces. These interfaces include SC net schedules, Control Area net schedules and/or individual transactions.
39		x						Call each adjacent Control Area and check that net schedules at each interface point match. Search for discrepancies and identify transactions that do not match. Resolve discrepancies with the involved SCs or eliminate the transactions with discrepancies.

ISO TARIFF APPENDIX D

Black Start Units

Black Start Units

The following requirements must be met by Generating Units providing Black Start ("Black Start Units"):

(a) Black Start Units must be capable of starting and paralleling with the ISO Controlled Grid without aid from the ISO Controlled Grid;

(b) Black Start Units must be capable of making a minimum number of starts per event (to be without aid from the ISO Controlled Grid as determined by the ISO);

(c) Black Start Units must be equipped with governors capable of operating in the stand alone (asynchronous) and parallel (synchronous) modes.

(d) Black Start Units must have startup load pickup capabilities at a level to be determined by the ISO, including total startup load (MW) and largest startup load (MW) for such power output levels as the ISO may specify.

(e) All Black Start Units must be capable of producing Reactive Power (boost) and absorbing Reactive Power (buck) as required by the ISO to control system voltages. This requirement may be met by the operation of more than one Black Start ~~u~~Unit in parallel providing that:

(i) the Black Start generation supplier demonstrates that the proposed Generation resource shares reactive burden equitably;

(ii) all Participating Generators associated with the proposed Black Start source are located in the same general area.

Buck/boost capability requirement shall be dependent on the location of the proposed resource in relation to Black Start load.

(f) All Black Start Units must have the following communication/control requirements:

(i) dial-up telephone;

(ii) backup radio;

(iii) manning levels which accord with Good Utility Practice.

ISO TARIFF APPENDIX E

Verification of Submitted Data for Ancillary Services

* * *

6. Treatment of Equal Price Bids. The ISO shall allow these Scheduling Coordinators to resubmit, at their own discretion, their bid no later than 2 hours the same day the original bid was submitted. In the event identical prices still exist following resubmission of bids, the ISO shall determine the merit order for each Ancillary Service by considering applicable constraint information for each Generating Unit, Load or other resource, and optimize overall costs for the Trading Day. If equal bids still remain, the ISO shall proportion participation in the Final Day-Ahead or Hour-Ahead Schedule (as the case may be) amongst the bidding Generating Units, Loads and resources with identical bids to the extent permitted by operating constraints and in a manner deemed appropriate by the ISO.

* * *

ISO TARIFF APPENDIX F

Rate Schedules

Schedule 1
Grid Management Charge

Part A – Monthly Calculation of Grid Management Charge (GMC)

The Grid Management Charge consists of seven separate service charges: (1) the Core Reliability Services Charge, (2) the Energy Transmission Services Net Energy Charge, (3) the Energy Transmission Services Uninstructed Deviations Charge, (4) the Forward Scheduling Charge, (5) the Congestion Management Charge, (6) the Market Usage Charge, and (7) the Settlements, Metering, and Client Relations Charge.

1. The rate in $/MW for the Core Reliability Services Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total of the forecasted Scheduling Coordinators' metered non-coincident peak hourly demand in MW for all months during the year.

2. The rate in $/MWh for the Energy Transmission Services Net Energy Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecast Metered Control Area Load in MWh.

3. The rate in $/MWh for the Energy Transmission Services Uninstructed Deviations Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the absolute value of total annual forecast net uninstructed deviations (netted within a ~~s~~Settlement ~~i~~Interval) in MWh.

4. The rate in $ per Schedule for the Forward Scheduling Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecast number of non-zero MW Final Hour-Ahead Schedules, including all awarded Ancillary Service bids.

5. The rate in $/MWh for the Congestion Management Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecast Scheduling Coordinators' inter-zonal scheduled flow (excluding flows pursuant to Existing Contracts) per path in MWh.

6. The rate in $/MWh for the Market Usage Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecast total purchases and sales (including out-of-market transactions) of Ancillary Services, Supplemental Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with uninstructed deviations being netted by ~~s~~Settlement ~~i~~Interval) in MWh.

7. The rate for the Settlements, Metering, and Client Relations Charge will be fixed at $500.00 per month, per Scheduling Coordinator Identification Number ("SC ID") with an invoice value other than $0.00 in the current trade month.

The rates for the foregoing charges shall be adjusted automatically each year, effective January 1 for the following twelve months, in the manner set forth in Part D of this Schedule.

Part B – Quarterly Adjustment, If Required

Each component rate of the Grid Management Charge will be adjusted automatically on a quarterly basis, up or down, so that rates reflect the annual revenue requirement as stated in the ISO's annual informational filing, if the estimated billing determinant volumes for that component, on an annual basis, change by 5% or more during the year. Such adjustment may be implemented not more than once per calendar quarter, and will be effective the first day of the next calendar month.

The rates will be adjusted in accordance with the following formula:

According to the formulae listed in Appendix F, Schedule 1, Part A with the billing determinant(s) readjusted on a going-forward basis to reflect the 5% or greater change from the estimated billing determinant provided in the annual informational filing.

Part C – Costs Recovered through the GMC

As provided in Section 8 of the ISO Tariff, the Grid Management Charge includes the following costs, as projected in the ISO's budget for the year to which the Grid Management Charge applies:

- Operating costs (as defined in Section 8.2.2)
- Financing costs (as defined in Section 8.2.3), including Start-Up and Development costs and
- Operating and Capital Reserve costs (as defined in Section 8.2.4)

Such costs, for the ISO as a whole, are allocated to the seven service charges that comprise the Grid Management Charge: (1) Core Reliability Services Charge, (2) Energy Transmission Services Net Energy Charge, (3) Energy Transmission Services Uninstructed Deviations Charge, (4) Forward Scheduling Charge, (5) Congestion Management Charge, (6) Market Usage Charge, and (7) Settlements, Metering, and Client Relations Charge, according to the factors listed in Part E of this Schedule 1, and

adjusted annually for:

- any surplus revenues from the previous year as deposited in the Operating and Capital Reserve Account, as defined under Section 8.5, or deficiency of revenues, as recorded in a memorandum account;

divided by:

- forecasted annual billing determinant volumes;

adjusted quarterly for:

- a change in the volume estimate used to calculate the individual Grid Management Charge components, if, on an annual basis, the change is 5% or more.

The Grid Management Charge revenue requirement formula is as follows:

Grid Management Charge revenue requirement =

- Operating Expenses + Debt Service + [(Coverage Requirement x Senior Lien Debt Service) and/or (Cash Funded Capital Expenditures)] - Interest Earnings - Other Revenues - Reserve Transfer

Where,

- **Operating Expenses** = O&M Expenses plus Taxes Other Than Income Taxes and Penalties

- **O&M Expenses** = Transmission O&M Expenses (Accounts 560-574) plus Customer Accounting Expenses (Accounts 901-905) plus Customer Service and Informational Expenses (Accounts 906-910) plus Sales Expenses (Accounts 911-917) plus Administrative & General Expenses (Accounts 920-935)
- **Taxes Other Than Income Taxes =** those taxes other than income taxes which relate to ISO operating income (Account 408.1)
- **Penalties** = payments by the ISO for penalties or fines incurred for violation of WECC reliability criteria (Account 426.3)
- **Debt Service** = for any fiscal year, scheduled principal and interest payments, sinking fund payments related to balloon maturities, repayment of commercial paper notes, net payments required pursuant to a payment obligation, or payments due on any ISO notes. This amount includes the current year accrued principal and interest payments due in April of the following year.
- **Coverage Requirement** = 25% of the Senior Lien Debt Service.
- **Senior Lien Debt Service** = all Debt Service that has a first lien on ISO Net Operating Revenues (Account 128 subaccounts).
- **Cash Funded Capital Expenditures** = Post current fiscal year capital additions (Accounts 301-399) funded on a pay-as-you-go basis.
- **Interest Earnings** = Interest earnings on Operating and Capital Reserve balances (Account 419). Interest on bond or note proceeds specifically designated for capital projects or capitalized interest is excluded.

- **Other Revenues** = Amounts booked to Account 456 subaccounts. Such amounts include but are not limited to application fees, WECC ~~secur~~reliability coordinator reimbursements, and fines assessed and collected by the ISO.
- **Reserve Transfer** = the projected reserve balance for December 31 of the prior year less the Reserve Requirement as adopted by the ISO Governing Board and FERC. If such amount is negative, the amount may be divided by two, so that the reserve is replenished within a two-year period. (Account 128 subaccounts)
- **Reserve Requirement** = 15% of Annual Operating Expenses.

A separate revenue requirement shall be established for each component of the Grid Management Charge by developing the revenue requirement for the ISO as a whole and then assigning such costs to the seven service categories using the allocation factors provided in Appendix F, Schedule 1, Part E of this Tariff.

Part D – Information Requirements

Budget Schedule

The ISO Governing Board shall set forth a budget schedule that shall specify the dates for the budget posting and public workshop events noted below and other significant budget related milestones providing an opportunity for public input.

Budget Posting

The ISO will post on its Internet site the preliminary proposed ISO operating and capital budget to be effective during the subsequent fiscal year, and the projected billing determinant volumes used to develop the rate for each component of the Grid Management Charge. Public Workshop

Subsequent to the website posting, and prior to (i) the ISO Governing Board approval of the budget and (ii) the submission of the informational filing described in the next paragraph of this Part D, the ISO shall hold a public budget workshop where it will provide an overview of and answer questions from stakeholders on the proposed budget, cost allocation, and the charges for each of the ISO's services for the following year.

Annual Informational Filing

The ISO will make a filing each year no later than December 15, or the first ~~b~~Business ~~d~~Day thereafter, at FERC that shall contain projected cost data on the ISO presented in conformance with the budget approved by the ISO Governing Board and the FERC Uniform System of Accounts (USOA). This filing shall contain such information as is required to update the GMC rates resulting from the application of the formulae in Part A of this Schedule for the following calendar year.

Periodic Financial ~~r~~Reports

The ISO will create periodic financial reports consisting of an income statement, balance sheet, statement of operating reserves, and such other reports as are required by the ISO Governing Board ~~of Governors~~. The periodic financial reports will be posted on the ISO's Website not less than quarterly.

* * *

Table 1

O&M, Debt Service, and Other Expense Recoveries Cost Allocation Factors

CC #	Cost Center	CRS	ETS	FS	CM	MU	SMCR	Total
			* * *					
1600	**Legal and Regulatory Division**	**36%**	**22%**	**4%**	**7%**	**17%**	**15%**	**100%**
1611	VP General Counsel - General	36%	22%	4%	7%	17%	15%	100%
1631	Legal and Regulatory	44%	22%	4%	5%	10%	16%	100%
1641	Market Analysis	15%	26%	0%	20%	31%	7%	100%
1642	Market Surveillance Committee	25%	25%	0%	25%	25%	0%	100%
1651	ISO Governing Board ~~of Governors~~	44%	22%	4%	5%	10%	16%	100%
1661	Compliance - General	22%	20%	12%	0%	29%	17%	100%
1662	Compliance - Audits	8%	0%	0%	0%	50%	42%	100%

* * *

Schedule 2

Other Charges

* * *

Replacement Reserves

The formulas for calculating the amount of and charges for Replacement Reserve Service are referenced in ISO Tariff Sections 2.5.27.4 and 2.5.28.4.

Black Start Capability

The user rate per unit of purchased Black Start ~~C~~capability for each Settlement Period will be calculated in accordance with ISO Tariff Section 2.5.28.6.

Imbalance Energy Charges

Rates for Imbalance Energy will be calculated in accordance with the formula in ISO Tariff Section 11.2.4.1.

* * *

ISO Tariff Appendix F
Schedule 3
High Voltage Access Charges

* * *

4. Transition Date

* * *

4.4 Application to Wheeling Access Charges. The transition described in this Section 4 shall also apply, on the same schedule, to High Voltage Wheeling Access Charges.

4.5 Conversion of Existing Rights. During the process by which a New Participating TO executes the Transmission Control Agreement, the ISO and potential New Participating TO that has an obligation to serve Load shall determine the amount of FTRs to be allocated to the New Participating TO for each Existing Right that the New Participating TO converts to Converted Rights. In making that determination, the ISO will consider the amount of contracted transmission capacity, the firmness of the contracted transmission capacity, and other characteristics of the contracted transmission capacity to determine the amount of FTRs to be given to the New Participating TO in accordance with Section 9.4.3 of the ISO Tariff.

5. Determination of the Access Charge.

5.1 The Access Charge consists of a High Voltage Access Charge (HVAC) that is based on a TAC Area component and an ISO Grid-wide component, a Transmission Charge, and a Low Voltage Access Charge (LVAC) that is based on a utility-specific rate established by each Participating TO in accordance with its TO Tariff.

5.2 Each Participating TO will develop, in accordance with Section 6 of this Schedule 3, a High Voltage Transmission Revenue Requirement ($HVTRR_{PTO}$) consisting of a Transmission Revenue Requirement for Existing High Voltage Facility ($EHVTRR_{PTO}$) and a Transmission Revenue Requirement for New High Voltage Facility ($NHVTRR_{PTO}$). The $HVTRR_{PTO}$ includes the TRBA adjustment described in Section 6.1 of this Schedule 3.

* * *

6 High Voltage Transmission Revenue Requirement.

6.1 The High Voltage Transmission Revenue Requirement of a Participating TO will be determined consistent with ISO procedures posted on the ISO Home Page and shall be the sum of:

(a) the Participating TO's High Voltage Transmission Revenue Requirement (including costs related to Existing Contracts associated with transmission by

others and deducting transmission revenues actually expected to be received by the Participating TO related to transmission for others in accordance with Existing Contracts, less the sum of the Standby Transmission Revenues); and

(b) the annual high voltage TRBA adjustment shall be based on the principal balance in the high voltage TRBA as of September 30, which shall be calculated as a dollar amount based on the projected Transmission Revenue Credits as adjusted for the true up of the prior year's difference between projected and actual credits. For a Participating TO that is not a UDC, MSS or a Scheduling Coordinator serving End-Use Customers and that does not have Gross Load in its TO Tariff in accordance with Appendix F, Schedule 3, Section 9, the Participating TO shall include any over- or under-recovery of its annual High Voltage Transmission Revenue Requirement in its high voltage TRBA. If the annual high voltage TRBA adjustment involves only a partial year of operations, the Participating TO's over- or under-recovery shall be based on a partial year revenue requirement, calculated by multiplying the Participating TO's High Voltage Transmission Revenue Requirement by the number of days the High Voltage Transmission Facilities were under the ISO's Operational Control divided by the number of days in the year.

* * *

8. Updates to High Voltage Access Charges.

* * *

8.2 related to such service shall be reflected in the High Voltage Access Charge, Low Voltage Access Charge, the High Voltage Transmission Revenue Requirement, or the Low Voltage Transmission Revenue Requirement of a Participating TO. For service provided by a Participating TO following the Transition Date, any refund associated with a Participating TO's Transmission Revenue Requirement that has been accepted by FERC, subject to refund, shall be provided as ordered by FERC. Such refund shall be invoiced separately from the Market Invoice.

8.3 If the Participating TO withdraws one or more of its transmission facilities from the ISO Operational Control in accordance with Section 3.4 of the Transmission Control Agreement, then the ISO will no longer collect the TRR for that transmission facility through the ISO's Access Charge effective upon the date the transmission facility is no longer under the Operational Control of the ISO. The withdrawing Participating TO shall be obligated to provide the ISO will all necessary information to implement the withdrawal of the Participating TO's transmission facilities and to make any necessary filings at

FERC to revise its TRR. The ISO shall revise its transmission Access Charge to reflect the withdrawal of one or more transmission facilities from ISO Operational Control.

9. Approval of Updated High Voltage Revenue Requirements

9.1 Participating TOs will make the appropriate filings at FERC to establish their Transmission Revenue Requirements for their Low Voltage Access Charges and the applicable High Voltage Access Charges, and to obtain approval of any changes thereto. All such filings with the FERC will include a separate appendix that states the HVTRR, LVTRR (if applicable) and the appropriate Gross Load data and other information required by the FERC to support the Access Charges. The Participating TO will provide a copy of its filing to the ISO and the other Participating TOs in accordance with the notice provisions in the Transmission Control Agreement.

* * *

APPENDIX H

Methodology for Developing the Weighted Average Rate for Wheeling Service

The weighted average rate payable for Wheeling over joint facilities at each Scheduling Point shall be calculated as follows, applying the formula separately to the applicable Wheeling Access Charges:

$$\text{WBAC} = \frac{\sum\left(P_n \times \frac{Q_n}{\sum Q_n}\right)}{}$$

Where:

WBAC = Weighted-average Wheeling Access Charge for each ISO Scheduling Point

P_n = The applicable Wheeling Access Charge rate for a TAC Area or Participating TO_n in $/kWh as set forth in Section 7.1.4 of the ISO Tariff and Section 5 of the TO Tariff.

Q_n = The Available Transfer Capacity (in MW), whether from transmission ownership or contractual entitlements, of each Participating TO_n for each ISO Scheduling Point which has been placed within the ISO Controlled Grid. Available Transfer Capacity shall not include capacity associated with Existing Rights of a Participating TO as defined in Section 2.4.4 of the ISO Tariff.

n = the number of Participating TOs from 1 to n

***

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ANCILLARY SERVICES REQUIREMENTS PROTOCOL

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***

ASRP 1.2.2 **Special Definitions for this Protocol**

In this Protocol, the following expression shall have the meaning set opposite it:

"Area Control Error (ACE)" means the sum of the instantaneous difference between the actual net interchange and the scheduled net interchange between the ISO Control Area and all adjacent Control Areas and the ISO Control Area's frequency correction and time error correction obligations.

"Dynamic Schedule" means a telemetered reading or value which is updated in real time and which is used as a schedule in the ISO EMS calculation of ACE and the integrated value of which is treated as a schedule for interchange accounting purposes.

~~**"ISO Home Page"** means the ISO internet home page at www.caiso.com or such other internet address as the ISO shall publish from time to time.~~

***

ASRP 2.1.1 **Basic criteria**

(a) The ISO shall base its Ancillary Services standards upon the Western Electricity~~System~~ Coordinating Council (W~~S~~ECC) Minimum Operating Reliability Criteria (MORC) and North American Electric Reliability Council (NERC) Criteria to the extent they are applicable to the ISO Controlled Grid.

(b) The ISO may adjust the Ancillary Services standards temporarily to take into account, among other things, variations in system conditions, real-time ~~d~~Dispatch constraints, contingencies, and voltage and dynamic stability assessments.

***

ASRP 2.2.1 **Grid Operations Committee Review**

The ISO Grid Operations Committee shall periodically undertake a review of the ISO Controlled Grid operations to determine any revision to the Ancillary Services standards to be used in the ISO Control Area. As a minimum the ISO Technical Advisory Committee shall conduct such reviews to accommodate revisions to W~~S~~ECC and NERC standards.

ASRP 2.2.2 **Contents of Grid Operations Committee Reviews**

Periodic reviews may include, but are not limited to:

(a) analysis of the deviation between actual and forecast Demand;

(b) analysis of patterns of unplanned Generating Unit Outages;

(c) analysis of compliance with NERC and WSECC Criteria;

(d) analysis of operation during system disturbances;

(e) analysis of patterns of shortfalls between Final Day-Ahead Schedules and actual Generation and Demand; and

(f) analysis of patterns of unplanned transmission Outages.

***

ASRP 3.2 **Right to Self-Provide**

Each Scheduling Coordinator may self-provide all, or a portion, of its Regulation and Reserve obligation within each Zone or adjust its obligation through Inter-Scheduling Coordinator Ancillary Service Trades

***

ASRP 4.1.1 **Basis for Standard**

The ISO needs sufficient Generating Units immediately responsive to Automatic Generation Control (AGC) in order to allow the ISO Control Area to meet the WSECC and NERC control performance criteria by continuously balancing Generation to meet deviations between actual and scheduled Demand and to maintain interchange schedules.

***

ASRP 4.1.3 **Percentage Determination**

The exact percentage required for each Settlement Period of the Day-Ahead Market and the Hour-Ahead Markets shall be determined by the ISO based upon its need to meet the WSECC and NERC control performance criteria.

***

ASRP 4.1.6 **Additional Regulation Requirement**

Additional Regulation capacity may be procured by the ISO for the real-time operating period if needed to meet the WSECC and NERC control performance criteria.

***

ASRP 4.5.2 **Certification and Testing Requirements**

Each Generating Unit and System Unit used to bid Regulation or used to self-provide Regulation must have been certified and tested by the ISO using the process defined in Appendix A to this Protocol.

***

ASRP 5 **OPERATING RESERVE STANDARDS**

The ISO needs, as a minimum, Operating Reserve, consisting of Spinning Reserve and Non-Spinning Reserve, sufficient to meet WSECC MORC. The Operating Reserve requirement shall be equal to (a) 5% of the Demand (except the Demand covered by firm purchases from outside the ISO Control Area) to be met by Generation from hydroelectric resources, plus 7% of the Demand (except the Demand covered by firm purchases from outside the ISO Control Area) to be met by Generation from other resources, or (b) the single largest Contingency, if this is greater or (c) by reference to such more stringent criteria as the ISO may determine from time to time. This Operating Reserve requirement does not include the Operating Reserve required to cover the Generation or services described in ASRP 5.2(a) and (b).

***

ASRP 5.2 **Standard for Non-Spinning Reserve: Quantity Needed**

The required quantity of Non-Spinning Reserve shall be equal to the required quantity of Operating Reserve less the quantity of Spinning Reserve determined in ASRP 5.1 plus;

(a) an amount of Non-Spinning Reserve equal to Interruptible Imports (which must either be self-provided by the Scheduling Coordinators responsible for the Interruptible Imports from resources within the ISO Controlled Grid or purchased from the ISO); and

(b) an amount of Non-Spinning Reserve equal to on-demand obligations to other entities or Control Areas (which must be self-provided by the Scheduling Coordinators responsible for the on-demand obligations from resources within the ISO Controlled Grid).

Scheduling Coordinators may self-provide their allocated quantity of Non-Spinning Reserve under ASRP 5.2(a) and (b) from Spinning Reserve not already committed to the ISO, if they wish.

***

ASRP 5.8.5 **Self-Provision of Operating Reserve**

Scheduling Coordinators may self-provide Spinning and Non-Spinning Reserves from resources outside the ISO Control Area.

***

ASRP 6.3 **Scheduling Coordinator's Obligation for Replacement Reserve**

Scheduling Coordinator's Obligation for Replacement Reserve for each Settlement Period of the Day-Ahead Market and for each Hour-Ahead Market in each ~~z~~Zone shall be based upon the ratio of the metered Demand (excluding exports) by each Scheduling Coordinator in each identified Zone for that Settlement Period to the total metered Demand (excluding exports) for that Settlement Period in that Zone.

***

ASRP 6.5.3 **Self-Provision of Replacement Reserve**

Scheduling Coordinators may self-provide Replacement Reserves as external imports from System Resources located outside the ISO Control Area.

***

ASRP 7.1 **Standard for Voltage Support: Quantity Needed**

The ISO shall determine on a daily basis for each Settlement Period for each Trading Day the quantity and location of Voltage Support required to maintain voltage levels and reactive margins within WSECC and NERC criteria using a power flow study based on the quantity and location of Demand scheduled in each Settlement Period of the Day-Ahead Market. The ISO shall issue daily voltage schedules (Dispatch instructions) to Generators, Participating TOs and UDCs for each Trading Day, which are required to be maintained for ISO Controlled Grid reliability.

***

ASRP 7.5.1 **Long-Term Voltage Support**

As of the ISO Operations Date, the ISO will contract for long-term Voltage Support service with Owners of Reliability Must-Run Units under Reliability Must-Run Contracts.

***

ASRP 10.2 **Performance Audit for Spinning Reserve**

The ISO will audit the performance of a Generating Unit or external import of a System Resource providing Spinning Reserve by auditing its response to Dispatch instructions and by analysis of Meter Data associated with the Generating Unit. Such audits may not necessarily occur on the hour. A Generating Unit providing Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move at the MW/minute capability stated in its bid, reach the amount of Spinning Reserve capacity scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO, and respond to system frequency deviations outside the allowed frequency deadband. An external import of a System Resource providing Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move at the MW/minute capability stated in its bid, reach the amount of Spinning Reserve capacity scheduled for the current sSettlement Period within ten minutes of issue of the Dispatch instruction by the ISO.

ASRP 10.3 **Performance Audit for Non-Spinning Reserve**

The ISO will audit the performance of a Generating Unit, Load, or System Resource providing Non-Spinning Reserve by auditing its response to Dispatch instructions, and by analysis of Meter Data associated with the resource. Such audits may not necessarily occur on the hour. A Generating Unit providing Non-Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction,

move in accordance with the time delay and MW/minute capability stated in its bid, and reach the amount of Non-Spinning Reserve capacity under the control of the ISO scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO. An external import of a System Resource providing Non-Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move in accordance with the time delay and MW/minute capability stated in its bid, and reach the amount of Non-Spinning Reserve capacity scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO. A Load providing Non-Spinning Reserve from Curtailable Demand shall be evaluated on its ability to respond to a Dispatch instruction, move in accordance with the time delay and MW/minute capability stated in its bid, and reach the amount of Non-Spinning Reserve capacity scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO.

***

ASRP 11.4 **Second failure**

An Ancillary Service resource which fails a compliance test or a performance audit conducted during the period when a warning notice for that resource is in effect shall be disqualified immediately from providing the Ancillary Service concerned whether as part of the ISO's auction or as part of a self-provision arrangement, and shall not be permitted to submit a bid to the ISO or be part of a self-provision arrangement until such time as it has successfully re-passed the approval and certification procedure described in the relevant Appendix to this ASRP.

DEMAND FORECASTING PROTOCOL (DFP)

***

DFP 1.1 Objectives

The objective of the DFP is to set forth procedures for submission of Demand Forecasts which will provide information to the ISO for projecting future Demand requirements to be served by the ISO Controlled Grid. The ISO shall utilize such forecasts to enable it to assess ~~s~~System ~~r~~Reliability and carry out its functions under the Scheduling Protocol (SP) and the Outage Coordination Protocol (OCP).

***

DFP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meaning set opposite them:

"Annual Peak Demand Forecast" means a Demand Forecast of the highest Hourly Demand in any hour in a calendar year, in MW.

"Congestion Zone" means a Zone identified as an Active Zone in Appendix I of the ISO Tariff.

"Hourly Demand" means the average of the instantaneous Demand integrated over a single clock hour, in MW.

~~**"ISO Home Page"** means the ISO internet home page at http://www.caiso.com/iso or such other internet address as the ISO shall publish from time to time.~~

"Weekly Peak Demand Forecast" means a Demand Forecast of the highest Hourly Demand in any hour in a period beginning at the start of the hour ending 0100 on Sunday and ending at the end of the hour ending 2400 the following Saturday, in MW.

***

DFP 3.1 Data to be Submitted to the ISO by UDCs

At the time specified in DFP 3.3, each UDC shall submit to the ISO its Weekly Peak Demand Forecasts by Congestion Zone reflecting the Weekly Peak Demand Forecast for ~~l~~Load expected to be served by facilities under the control of the UDC. All Weekly Peak Demand Forecasts submitted shall include Demand Forecasts for the following 52 weeks.

DISPATCH PROTOCOL

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***

DP 1.1 Objectives

The objectives of this Protocol are:

(a) to implement those sections of the ISO Tariff which involve real-time and emergency operations;

(b) to describe the real-time Dispatch of the Ancillary Services specified in the Ancillary Services Requirements Protocol (ASRP);

(c) to describe the operational activities of the ISO after all commitments have been made in the Hour-Ahead Market as described in the Scheduling Protocol (SP);

(d) to describe the use of Supplemental Energy bids received by the ISO in accordance with the Schedules and Bids Protocol (SBP); and

(e) to describe how the ISO will meet the operational requirements of NERC and WSECC guidelines.

***

DP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meanings set opposite them:

"Backup ISO Control Center" means the ISO Control Center located in Alhambra, California.

"Control Area Operator" means the person responsible for managing the real-time operations of a Control Area.

"Dispatch Instruction" means an operating order that is issued by the ISO to a Participant pertaining to real-time operations.

"GCC" means the single point of contact at the grid control center of Southern California Edison Company.

~~**"ISO Home Page"** means the ISO internet home page at http://www.caiso.com or such other internet address as the ISO shall publish from time to time.~~

"Primary ISO Control Center" means the ISO Control Center located in Folsom, California.

"Participant" means any of those entities referred to in DP 1.3.1(a)-(f).

"Power System Stabilizer (PSS)" means an electronic control system applied on a Generating Unit that helps to damp out dynamic oscillations on a power system. The PSS senses Generator variables,

such as voltage, current and shaft speed, processes this information and sends control signals to the Generator voltage regulator.

"Qualifying Facility" means a qualifying co-generation or small power production facility recognized by FERC.

"~~Secur~~Reliability Coordinator" means the person responsible for Security Monitoring in real time for the California Area.

"TOC" means the single point of contact at the transmission operations center of Pacific Gas & Electric Company.

"Total Transfer Capability (TTC)" means the amount of power that can be transferred over an interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre-contingency and post-contingency system conditions.

"Western Interconnection" means a network of transmission lines embodied within the W~~S~~ECC Region.

***

DP 2 STANDARDS TO BE OBSERVED

DP 2.1 Applicable Reliability Criteria

The ISO shall exercise Operational Control over the ISO Controlled Grid in compliance with all Applicable Reliability Criteria. Applicable Reliability Criteria are defined as the standards established by NERC, W~~S~~ECC and Local Reliability Criteria and include the requirements of the Nuclear Regulatory Commission (NRC).

DP 2.1.1 W~~S~~ECC Criteria (Standards)

(a) Western Interconnection

The W~~S~~ECC set of standards for the Western Interconnection, which are based on the NERC standards. The W~~S~~ECC further defines procedures and policies applicable to the Western Interconnection. W~~S~~ECC guidelines include:

(i) Part 1 – Reliability Criteria for Transmission System Planning

(ii) Part 2 – Power Supply Design Criteria

(iii) Part 3 – Minimum Operating Reliability Criteria (MORC)

(iv) Part 4 – Definitions

(b) Operating Procedures

The W~~S~~ECC Operating Procedures submitted to W~~S~~ECC by individual utilities and the ISO to address specific operating problems in their respective grids that could affect operations of the interconnected grid.

(c) Dispatcher's Handbook

The WSECC Dispatcher's Handbook supplied by WSECC to all utilities and Control Areas as a reference for dispatchers to use during normal and emergency operations of the grid.

***

DP 2.2 Ancillary Services

The ISO will base its standards for the Dispatch of Ancillary Services upon WSECC MORC and ISO Controlled Grid reliability requirements.

DP 2.3 ISO Standards

The ISO Governing Board may establish guidelines more stringent than those established by NERC and WSECC as needed for the secure and reliable operation of the ISO Controlled Grid.

***

DP 3 SCHEDULING AND REAL-TIME INFORMATION

DP 3.1 Final Schedules

The scheduling process described in the SP will produce for the ISO real-time dispatchers for each Settlement Period of the Trading Day a Final Schedule consisting of the combined commitments contained in the Final Day-Ahead Schedules and the Final Hour-Ahead Schedules for the relevant Settlement Period. The Final Schedule will include information with respect to:

(a) Generation schedules;

(b) Demand schedules;

(c) Ancillary Services schedules based on the ISO's Ancillary Services auction;

(d) Ancillary Services schedules, based on SCs' ISO accepted schedules and forecast load, for self-provided Ancillary Services;

(e) Interconnection schedules between the ISO Control Area and other Control Areas; and

(f) Inter-Scheduling Coordinator Energy Trades.

DP 3.2 Supplemental Energy

In addition to the Final Schedules, Supplemental Energy bids will be available to the ISO real-time dispatchers, as described in the SBP, by

sixty (60) minutes prior to the start of the Settlement Period to which such Supplemental Energy bids apply.

DP 3.3 SC Intertie Schedules

In accordance with the SBP and the SP, SCs shall provide the ISO with Interconnection schedules prepared in accordance with all NERC, W~~S~~ECC and ISO requirements. The provisions of the SBP and the SP shall apply to real~~-~~-time changes in Interconnection schedules under Existing Contracts.

***

DP 3.8.1 System Status Change

The ISO and each adjacent Control Area Operator shall keep each other informed of any change or potential change in the status of the Interconnection and any changes in the Interconnection's TTC. The ISO and each adjacent Control Area Operator shall keep each other

informed of situations such as adverse weather conditions, fires, etc., that could affect the reliability of any Interconnection. Each Control Area Operator of the Control Areas in the California area, as defined by the W~~S~~ECC Regional Security Plan, shall keep the ISO informed of all information required by W~~S~~ECC for use by the ~~Secur~~Reliability Coordinator.

DP 3.8.2 Scheduling Procedure

The ISO and each adjacent Control Area Operator shall follow all applicable NERC and W~~S~~ECC scheduling procedures. This will include checking the Interconnection schedules for the next Settlement Period prior to the start of the Energy ramp going into that hour. The ISO and each adjacent Control Area Operator shall check and agree on actual MWh net interchange after the hour for the previous Settlement Period. One Control Area shall change its actual number to reflect that of the other Control Area in accordance with W~~S~~ECC standard procedures.

***

DP 6.1 Overview/Responsibility

The ISO shall operate the ISO Controlled Grid in accordance with the standards described in DP 2 and within the limit of all applicable ~~n~~Nomograms and established operating limits and procedures.

***

DP 6.8 **Outages**

The ISO will coordinate and approve Maintenance Outages and coordinate responses to Forced Outages of all transmission facilities in the ISO Controlled Grid and Reliability Must-Run Units in accordance with the OCP.

Any scheduled Outages that are cancelled by ISO real-time operations due to system requirements must be rescheduled with the ISO Outage Coordination Department in accordance with the OCP.

DP 6.9 **Security Monitoring**

The ISO shall be the ~~Secur~~Reliability Coordinator for the California Area. As ~~Secur~~Reliability Coordinator, the ISO, in conjunction with the other WSECC ~~Secur~~Reliability Coordinators, will be responsible for the stable and reliable operation of the Western Interconnection in accordance with the WSECC Regional Security Plan.

DP 6.9.1 **~~Secur~~Reliability Coordinator**

As ~~Secur~~Reliability Coordinator, the ISO may direct activities as appropriate to curtail Schedules, Dispatch Generation or impose transfer limitations as necessary to relieve grid Congestion, mitigate potential overloads or eliminate operation outside of existing ~~n~~Nomogram criteria.

DP 6.9.2 **Authority of WSECC ~~Secur~~Reliability Coordinators**

(a) The ~~Secur~~Reliability Coordinator has the final authority to direct operations before, during and after problems or disturbances that have regional impacts. The WSECC ~~s~~Security ~~m~~Monitoring plans include collaboration with sub-regional ~~Secur~~Reliability Coordinators and ~~c~~Control ~~a~~Area operators to determine actions for anticipated problems. If there is insufficient time, or mutual concurrence is not reached, the ~~Secur~~Reliability Coordinator is authorized to direct actions and the control area operators must comply.

(b) In the event of any situation occurring which is outside those problems already identified in the list of known problems, the ~~Secur~~Reliability Coordinator shall have the responsibility and authority to implement whatever measures are necessary to maintain ~~s~~System ~~r~~Reliability. Those actions include but are not limited to; interchange curtailment, generation Dispatch adjustment (real power, reactive power and voltage), transmission configuration adjustments, special protection activation, load curtailment and any other action deemed necessary to maintain ~~s~~System ~~r~~Reliability.

(c) The ~~Secur~~Reliability Coordinator shall also have the responsibility and authority to take action in its sub-region for problems in another sub-region that it may help resolve. This

must be accomplished at the request of and in coordination with the ~~Secur~~Reliability Coordinators of the other sub-regions.

DP 7 REAL-TIME OPERATIONAL ACTIVITIES – THE HOUR PRIOR TO THE SETTLEMENT PERIOD

***

DP 8 REAL-TIME OPERATIONAL ACTIVITIES – THE SETTLEMENT PERIOD

***

DP 8.1.1 Responsibility of the ISO in Real-Time Dispatch

During ~~R~~real-~~T~~time Dispatch, the ISO, using RTD Software will be responsible for Dispatching Generating Units, Curtailable Demands and Interconnection schedules to meet real-time imbalances between actual and scheduled Demand and Generation and to relieve Congestion, if necessary, to ensure System Reliability and to maintain Applicable Reliability Criteria.

***

DP 8.2 Generating Units, Loads and Interconnection Schedules Dispatched for Congestion

The ISO will use the RTD Software to alleviate Inter-Zonal Congestion as described in DP 8.3. The ISO will manage Intra-Zonal Congestion in real-time as set forth in Section 7.2.6.

***

DP 8.3.1 Treatment by Zone

If there is Inter-Zonal Congestion in real time, the ISO's RTD ~~s~~Software shall increase Generation and/or reduce Demand separately for each Zone to optimally Dispatch available resources to resolve the Congestion.

***

DP 8.4 Intra-Zonal Congestion

Except as provided in Section 5.2 of the ISO Tariff, in the event of Intra-Zonal Congestion, the ISO shall adjust Generating Units and Curtailable Demands (or Interconnection schedules of System Resources in the Control Areas) to alleviate the ~~c~~Constraints as described in Section 7.2.6.

***

DP 8.6 Real-Time Dispatch Application

DP 8.6.1 Real-Time Dispatch

During real time, the ISO shall Dispatch Generating Units, Curtailable Demands and Interconnection schedules to meet imbalances between actual and scheduled Demand and Generation.

In addition, the ISO may need to purchase additional Ancillary Services if Ancillary Services arranged in advance are used to provide balancing Energy, and such depletion needs to be recovered to meet System Reliability contingency requirements.

DP 8.6.2 Utilization of the Energy Bids

The ISO will use the Energy Bids to Dispatch Supplemental Energy and Ancillary Services to procure balancing Energy for:

(a) satisfying needs for Imbalance Energy;

(b) mitigating Inter-Zonal Congestion;

(c) allowing resources providing Regulation service to return to the preferred operating point within their regulating ranges;

(d) allowing recovery of Operating Reserves utilized in real-time operations;

(e) procuring additional Voltage Support required from resources beyond their power factor ranges in real time; and

(f) Dispatching System Resources and Dispatchable Loads and increasing Generating Units' output to manage Intra-Zonal Congestion in real time using Energy Bids Dispatched out of sequence.

DP 8.6.3 Basis for Real-Time Dispatch

The ISO shall base real-time Dispatch of Generating Units, Curtailable Demands and Interconnection schedules on the following principles:

(a) the ISO shall Dispatch Generating Units and Dispatchable Interconnection schedules providing Regulation service to meet W~~S~~ECC and NERC Area Control Error (ACE) performance criteria;

(b) in each Dispatch Interval, following the loss of a resource and once ACE has returned to zero, the ISO shall determine if the Regulation Generating Units and Dispatchable Interconnection schedules are operating at a point away from their Set Point. The ISO shall then adjust the output of Generating Units, Curtailable Demands, and Dispatchable Interconnection schedules (either providing Spinning Reserve, Non-Spinning Reserve, Replacement Reserve, or Supplemental Energy) to return the Regulation Generating Units and Dispatchable Interconnection schedules to their Set Points to restore their full regulating margin;

(c) in each Dispatch Interval, the ISO shall Dispatch Generating Units, Curtailable Demands and Dispatchable Interconnection schedules to meet its balancing Energy requirements and eliminate any Price Overlap between Energy Bids, thereby, Dispatching the relevant resources in real time for economic trades either between SCs or within a SC's portfolio;

(d) the ISO shall select the Generating Units, Curtailable Demands and Dispatchable Interconnection schedules to be Dispatched to meet its balancing Energy requirements in merit order according to their Energy Bids;

(e) the ISO shall not discriminate between Generating Units, Curtailable Demands and Dispatchable Interconnection schedules other than based on price, and the effectiveness (location and ramp rate) of the resource concerned to respond to the fluctuation in Demand or Generation, or to resolve Inter-Zonal Congestion;

(f) Generating Units, Curtailable Demands or Dispatchable Interconnection schedules shall be Dispatched during the Settlement Period only until the next variation in Generation or Demand or the end of the Settlement Period, whichever is sooner. In Dispatching such resources, the ISO may make commitments beyond the current Settlement Period;

(g) The ISO will not differentiate between Ancillary Services procured by the ISO and Ancillary Services which are being self-provided;

(h) [Not Used]

(i) The operational ramp rate(s) of a resource will be considered by the RTD sSoftware in determining the amount of Instructed Imbalance Energy by Dispatch Interval, and such consideration may result in Instructed Imbalance Energy in Dispatch Intervals prior to or subsequent to the Dispatch Interval to which the Dispatch Instruction applies;

(j) System Resources identified as Dispatchable within the operating hour pursuant to SBP Section 6.1.3 shall be Dispatched optimally through the RTD Software. Such bids will be settled pursuant to Section 11.2.4.1.1.2;

(k) The ISO will pre-dispatch Energy Bids from System Resources, subject to Hourly Pre-Dispatch as indicated in SBP 6.1.3, prior to the beginning of each hour consistent with applicable WSECC interchange scheduling practices, assuring that any

Price Overlap between such decremental and incremental Energy Bids will be eliminated. Such bids will be settled pursuant to Section 11.2.4.1.1.2.

***

DP 8.7.3 Replacement Reserve

(a) Replacement Reserve provided from Generating Units, Curtailable Demands and Interconnection schedules must meet the standards specified in the ASRP;

(b) the ISO will utilize Replacement Reserve to replace Operating Reserve that has been Dispatched due to a shortfall in Generation or an increase in Demand;

(c) the ISO may Dispatch Replacement Reserve to replace Operating Reserve that has been Dispatched for balancing Energy; and

(d) the ISO will Dispatch Replacement Reserve in merit order of Energy ~~b~~Bid prices as determined by RTD;

DP 8.7.4 Replacement of Operating Reserve

(a) in the event of an un-forecasted increase in system Demand or a shortfall in Generation output, the ISO shall utilize Replacement Reserve to restore Operating Reserve;

(b) if pre-arranged Operating Reserve is used to meet balancing Energy requirements, the ISO may replace such Operating Reserve by Dispatch of additional balancing Energy available from Supplemental Energy bids;

(c) any additional Operating Reserve needs may also be met the same way;

(d) where the ISO elects to rely upon Supplemental Energy bids, the ISO shall select the resources with the lowest incremental Energy ~~b~~Bid price as established by RTD; and

(e) if the ISO restores Operating Reserve through utilization of Replacement Reserve, the ISO is not required to replace the utilized Replacement Reserve;

***

DP 8.7.6 Black Start

(a) Black Start shall meet the standards specified for Black Start in the ASRP; and

(b) the ISO will Dispatch Black Start as required in accordance with the applicable Black Start ~~a~~Agreement.

DP 8.8 Real-~~-~~Time Management of Overgeneration Conditions

In the event that Overgeneration conditions occur during real time, the ISO will direct the SCs to take the steps described in Section 2.3.4 of the ISO Tariff and SCs shall implement ISO directions without delay.

***

DP 10.1.1 System alert

ISO will give a system ~~a~~Alert ~~n~~Notice when the operating requirements of the ISO Controlled Grid are marginal because of Demand exceeding forecast, loss of major Generation or loss of transmission capacity that has curtailed imports into the ISO Control Area, or if the Hour-Ahead Market is short on scheduled Energy and Ancillary Services for the ISO Control Area.

***

DP 10.1.3 System Emergency

When, in the judgement of the ISO, the System Reliability of the ISO Controlled Grid is in danger of instability, voltage collapse or under-frequency caused by transmission or Generation trouble in the ISO Control Area, or events outside of the ISO Control Area that could result in a cascade of events throughout the W~~S~~ECC grid, the ISO will declare a System Emergency. This declaration may include a notice to suspend the Day-Ahead, Hour-Ahead and Real Time Markets, authorize full use of Black Start Generation, initiate full control of manual Load Shedding, authorize the curtailment of Curtailable Demand (even though not scheduled as an Ancillary Service). The ISO will reduce the System Emergency declaration to a lower alert status when it is satisfied, after conferring with ~~Secur~~Reliability Coordinators within the W~~S~~ECC that the major contributing factors have been corrected, all involuntarily interrupted Demand is back in service (except interrupted Curtailable Demand selected as an Ancillary Service). This reduction in alert status will reinstate the competitive markets if they have been suspended.

***

DP 10.2.2 Emergency Procedures

In the event of a System Emergency, the ISO shall:

(a) take action as it considers necessary to preserve or restore stable operation of the ISO Controlled Grid;

(b) act in accordance with Good Utility Practice to preserve or restore reliable, safe and efficient service as quickly as reasonably practicable;

(c) keep adjacent Control Area Operators informed as to the nature and extent of the System Emergency in accordance with WSECC procedures; and

(d) where practicable, keep the Participants within the ISO Control Area informed.

***

DP 10.3 External Support/Assistance

If, on a real-time basis, the ISO is unable to comply with the Applicable Reliability Criteria, the ISO shall take such steps as it considers necessary, to ensure compliance, including the negotiation of contracts for Ancillary Services through processes other than competitive solicitations. If the ISO is unable to obtain such resources from within the ISO Controlled Grid, the ISO may solicit Ancillary Services from other Control Areas on a real-time basis.

***

DP 10.4.2 Load Curtailment

A SC may specify that Load will be reduced at specified Market Clearing Prices or offer the right to exercise Load curtailment to the ISO as an Ancillary Service or utilize Load curtailment itself (by way of self-provision of Ancillary Services) as Non-Spinning Reserve or Replacement Reserve. The ISO, at its discretion, may require direct control over such Curtailable Demand to assume response capability for managing System Emergencies. The ISO may establish standards for automatic communication of curtailment instructions to implement Load curtailment as a condition for accepting any offered Load curtailment as an Ancillary Service.

***

ISO MARKET MONITORING AND INFORMATION PROTOCOL

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ISO MARKET MONITORING AND INFORMATION PROTOCOL (MMIP)

***

MMIP 1.2.2 Special Terms for This Protocol

In this Protocol, the following words and expressions shall have the meanings set opposite them:

"Market Surveillance Unit" means the unit established under MMIP 3.1.

"ISO Market Surveillance Committee (ISO MSC)" means the committee established under MMIP 5.1.

"Activity Rules" means the rules relating to the activities of ISO ~~or PX~~ Participants set forth in or referred to in the ISO ~~and PX~~ Tariff and Protocols.

~~**"ISO Home Page"** means the ISO internet home page at http://www.caiso.com or such other internet address as the ISO shall publish from time to time.~~

***

~~**MMIP 1.3.1.2** PX Participants;~~

MMIP 1.3.1.2~~3~~ The ISO.

***

MMIP 2.1.3 Gaming

"Gaming", or taking unfair advantage of the rules and procedures set forth in the ~~PX or~~ ISO Tariff~~s~~, Protocols or Activity Rules, or of transmission c~~C~~onstraints in periods in which exist substantial Congestion, to the detriment of the efficiency of, and of consumers in, the ISO Markets. "Gaming" may also include taking undue advantage of other conditions that may affect the availability of transmission and generation capacity, such as l~~L~~oop f~~F~~low, facility outages, level of hydropower output or seasonal limits on energy imports from out-of-

state, or actions or behaviors that may otherwise render the system and the ISO Markets vulnerable to price manipulation to the detriment of their efficiency.

MMIP 2.1.4 ISO and Other~~PX~~ Design Flaws

Design flaws and inefficiencies in the ISO Tariff, ISO Protocols and operational rules and procedures of the ISO, including the potential for problems between the ISO and other independent power exchanges ~~including the PX~~, insofar as they affect the ISO Markets which may be evident from anomalous market behavior monitored under MMIP 2.1.1 above, from evidence of gaming monitored under MMIP 2.1.3 above, or from other activities.

***

MMIP 2.2.2 IOU Mitigation Plans

The Market Surveillance Unit shall review all IOU mitigation plans, as approved and modified by the FERC and other regulatory agencies, that might affect the competitiveness of and the efficient operation of the ISO Markets. ~~In consultation with the Compliance Unit of the PX, t~~The Market Surveillance Unit shall analyze what further actions may be necessary to ensure the effective implementation of these mitigation plans with respect to the ISO Markets, and may make such recommendations for further actions as it considers appropriate to the ISO CEO and Governing Board, the FERC, the CPUC or other regulatory agencies. The Market Surveillance Unit shall monitor the ongoing implementation of such plans to the extent feasible within the area of its responsibility, capability and resources.

MMIP 2.2.3 Effects Pending Divestiture

In the pre-divestiture period, the Market Surveillance Unit shall monitor and analyze the combined effect of the operations of the CTC and the rate freeze under which the Companies are required to operate during the pre-divestiture period on the state of competition in and the efficient operation of the ISO Markets~~; and the Market Surveillance Unit shall consult with the Compliance Unit of the PX with respect to such effects on both the PX and ISO Markets~~.

MMIP 2.3 Response Action by ISO

MMIP 2.3.1 Corrective Actions

Where the monitoring activities or any consequent investigations carried out by the Market Surveillance Unit pursuant to MMIP 2 and MMIP 4 reveal a significant possibility of the presence of or potential for exercises of market

power that would adversely affect the operation of the ISO Markets, or the markets ~~administered by the PX or~~ otherwise operating in the State of California, the Market Surveillance Unit shall take the appropriate measures under this section and under MMIP 4, 6, and 7 to institute the corrective action most effective and appropriate for the situation or, in the case of markets ~~administered by the PX or~~ otherwise operating in the State of California, the Market Surveillance Unit may recommend corrective actions ~~to the PX or~~ to the appropriate regulatory agencies.

MMIP 2.3.2 Further Actions

Where the monitoring activities of or any consequent investigations carried out by the Market Surveillance Unit pursuant to MMIP 2.1 and 2.2 reveal that activities or behavior of Market Participants in the ISO Markets have the effect of, or potential for, undermining the efficiency, workability or reliability of the ISO Markets to give or to serve such Market Participants an unfair competitive advantage over other Market Participants, the Market Surveillance Unit shall fully investigate and analyze the effect of such activities or behavior and, where appropriate, make recommendations to the ISO CEO and the ISO MSC for further action by the ISO or, where necessary, by other entities. The ISO may publicize such activities or behavior and it's recommendations thereof, in whatever medium it believes most appropriate. The Market Surveillance Unit may, where appropriate, make specific recommendations for amendment to rules and protocols under its control, ~~or for referral to the PX as to rules and protocols under the PX's control,~~ or for changes to the structure of the ISO Markets, ~~or by referral to the PX, of the markets administered by the PX,~~ and the Market Surveillance Unit may recommend actions, including fines or suspensions, against specific entities in order to deter such activities or behavior.

MMIP 2.3.3 Response to Gaming Behavior

If evidence of "gaming" or taking undue advantage exists, as described in MMIP 2.1.4, the Market Surveillance Unit shall, ~~in cooperation with the PX Compliance Unit where appropriate,~~ review the "gaming" behavior and/or the relationship between system conditions and market behavior and pricing in order to assess the potential for and impact of such gaming behavior, with a view to taking appropriate action, if necessary, either with respect to structural changes such as Zone changes, or to changes to the ISO ~~or PX~~ Tariffs, Protocols or Activity Rules, or to proscribe specific behavior by Market Participants. In carrying out such activities the Market Surveillance Unit shall in appropriate circumstances seek the advice of the ISO MSC on the merits of such actions. In appropriate circumstances, the Market Surveillance Unit may institute or arrange for ADR procedures involving Market Participants with conflicting perspectives, e.g. as to

whether a particular practice is better characterized as improper gaming or legitimate aggressive competition or as to whether rule changes may resolve conflicts.

MMIP 2.3.4 Adverse Effects of Transition Mechanisms

Should the monitoring and analysis conducted under MMIP 2.2.3 reveal significant adverse effects of transition mechanisms on competition in or the efficient operation of the ISO Markets, the Market Surveillance Unit shall examine and fully assess the efficacy of all possible measures that may be taken by the ISO ~~and, in consultation with the Compliance Unit of the PX, all possible measures that may be taken by the PX~~, in order to prevent or to mitigate such adverse effects. The Market Surveillance Unit shall make such recommendations to the CEO of the ISO and to the ISO MSC as it considers appropriate for action in this regard by ~~the PX or~~ the ISO or for referral to the regulatory or antitrust enforcement agencies. Such proposed measures may include, but shall not be limited to the following:

***

MMIP 3.3.5 Complaints

Any Market Participant, or any other interested entity, may at any time submit information to or make a complaint to the Market Surveillance Unit concerning any matter that it believes may be relevant to the Market Surveillance Unit' s monitoring responsibilities. Such submissions or complaints may be made on a confidential basis in which case the Market Surveillance Unit shall preserve the confidentiality thereof. The Market Surveillance Unit, at its discretion, may request further information from such entity and carry out any investigation that it considers appropriate as to the concern raised. The Market Surveillance Unit shall periodically make reports to the ISO CEO and ISO Governing Board on complaints received.

***

MMIP 4.3 Review of Activity Rules

When an iterative bidding process is developed that requires the application of Activity Rules~~, whether~~ developed by the ISO ~~or the PX~~, the Market Surveillance Unit shall review such Activity Rules for their effectiveness and consistency with

its market monitoring activities and standards. The Market Surveillance Unit may at that time, and from time to time thereafter based on its experience in monitoring the ISO Markets, propose that changes be made in such Activity Rules.

***

MMIP 4.5 ISO Participants

MMIP 4.5.1 Collection of Data

The Market Surveillance Unit may request the submission of any information or data determined by the Market Surveillance Unit to be potentially relevant by ISO Participants~~, the PX~~ or other entities whose activities may affect the operation of the ISO ~~m~~Market. This data will be subject to due safeguards to protect confidential and commercially sensitive data. Failures by ISO Participants to provide such data shall be treated under MMIP 4.5.2. In the event of failures by other entities to provide such data, the Market Surveillance Unit may report the failure to the ISO CEO and Governing Board or the pertinent regulatory agency, as appropriate, after providing such entity the opportunity to respond in writing as to the reason for the alleged failure.

***

~~**MMIP 4.7 Cooperation with PX Compliance Unit and Market Monitoring Committee**~~

~~In carrying out its responsibilities under this Protocol, the Market Surveillance Unit may at its discretion consult or cooperate in the manner it considers most appropriate with the PX' s Compliance Unit and Market Monitoring Committee, or other entities within the PX that fulfill the analogous market monitoring functions, with respect to the following:~~

~~(a) exchange of data subject to any limitations on the ISO's ability to disclose commercially sensitive information from other Scheduling Coordinators to the ISO, monitoring methodologies and results, and information on corrective, referral or enforcement actions taken;~~

~~(b) monitoring of market performance;~~

~~(c) joint analysis of data, subject to any limitations on the ISO' s ability to disclose commercially sensitive information from other Scheduling~~

~~Coordinators to the ISO, and monitoring results of markets and Market Participant behavior;~~

~~(d) investigations of specific market abuses; and~~

~~(e) proposals for concerted action on enforcement measures, e.g., as to suspensions from trading.~~

MMIP 4.7~~8~~ Liability for Damages

As provided in Section 14.1 and 14.2 of the ISO Tariff, the Market Surveillance Unit, the ISO MSC, the ISO CEO and other ISO staff shall not be liable to any Market Participant under any circumstances whatsoever for any matter described in those sections, including but not limited to any financial loss or loss of economic advantage resulting from the performance or non-performance by such ISO entities of their functions under this Protocol.

***

MMIP 5.2.1.2 experience in operational aspects of ~~g~~Generation and transmission in electricity markets;

***

MMIP 5.2.2.1 no material affiliation, through employment, consulting or otherwise, with any Market Participant or ~~a~~Affiliate thereof consistent with the pertinent FERC Standards of Conduct; and

MMIP 5.2.2.2 no material financial interest in any Market Participant or ~~a~~Affiliate thereof consistent with the pertinent FERC Standards of Conduct.

***

MMIP 6.2 Evaluation of Information

The ISO MSC may, upon request of the Market Surveillance Unit, the ISO CEO or the ISO Governing Board, or on its own volition, evaluate such information or data, including as may be collected by the Market Surveillance Unit on the basis of the evaluation criteria developed by the Market Surveillance Unit or on such

further articulated evaluation criteria developed by the ISO MSC. ~~In carrying out such evaluations, the ISO MSC may consult the PX's Compliance Unit and Market Monitoring Committee with respect to any matter relating to such evaluations.~~

***

APPENDIX A

ISO Market Monitoring Plan

Market Mitigation Measures

***

1.2 In addition, the ISO shall monitor the markets it administers for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the ISO. If the ISO identifies any such conduct, and in particular conduct exceeding the thresholds for presumptive market effects specified below, it shall make a filing under Section 205 of the Federal Power Act, 16 U.S.C. § 824d, with FERC~~the Commission~~ requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the ISO believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the ISO's justification for imposing that mitigation measure.

2 CONDUCT WARRANTING MITIGATION

2.1 Definitions

The following definitions are applicable to this Appendix A:

"Economic Market Clearing Prices" are the ~~m~~Market ~~c~~Clearing ~~p~~Prices for a particular resource at the location of that particular resource at the time the

resource was either Scheduled or was Dispatched by the ISO. Economic Market Clearing Prices may originate from the Day-aAhead Energy market, the Hour-aAhead Energy market (when these markets are in place), or ISO Rreal-time Imbalance Energy market. The Economic Market Clearing Price for the ISO Rreal-Ttime Imbalance Energy Mmarket shall be the Dispatch Interval Ex Post Price, unless the resource cannot change output level within the hour (i.e., the resource is not amenable to intra-hour real-time Dispatch instructions), or it is a System Resource. Economic Market Clearing Prices for the ISO Rreal-Ttime Imbalance Energy Mmarket for resources that cannot change output level within one Dispatch Interval and System Resources shall be the simple average of the relevant Dispatch Interval Ex Post Prices for each hour.

"Electric Facility" shall mean an electric resource, including a Generating Unit, System Unit, or a Participating Load.

2.2 Conduct Subject to Mitigation

Mitigation Measures may be applied: (i) to the bidding, scheduling, or operation of an "Electric Facility"; or (ii) as specified in sSection 2.4 below.

***

2.4 Categories of Conduct that May Warrant Mitigation

2.4.1 The following categories of conduct, whether by a single firm or by multiple firms acting in concert, may cause a material effect on prices or generally the outcome of the ISO Real Time Market if exercised from a position of market power. Accordingly, the ISO shall monitor the ISO Markets for the following categories of conduct, and shall impose appropriate Mitigation Measures if such conduct is detected and the other applicable conditions for the imposition of Mitigation Measures are met:

(1) Physical withholding of an Electric Facility, in whole or in part, that is, not offering to sell or schedule the output of or services provided by an Electric Facility capable of serving an ISO Market. Such withholding may include, but not be limited to: (i) falsely declaring that an Electric Facility has been forced out of service or otherwise become totally or partially unavailable, (ii) refusing to offer bids or schedules for an Electric Facility when it would be in the economic interest, absent market power, of the withholding entity to do so, (iii) declining real-time bids called upon by the ISO (unless the ISO is informed in accordance with established procedures that the relevant resource for which the bid is submitted has undergone a forced outage or derate), or (iv) operating a Generating Unit in real-time to produce an output level that is less than the ISO's Dispatch instruction.

(2) Economic withholding of an Electric Facility, that is, submitting bids for an Electric Facility that are unjustifiably high (relative to known operational characteristics and/or the known operating cost of the resource) so that: (i) the

Electric Facility is not or will not be dispatched or scheduled, or (ii) the bids will set a ~~m~~Market ~~c~~Clearing ~~p~~Price.

(3) Uneconomic production from an Electric Facility, that is, increasing the output of an Electric Facility to levels that would otherwise be uneconomic in order to cause, and obtain benefits from, a transmission constraint

***

3 CRITERIA FOR IMPOSING MITIGATION MEASURES

3.1 Identification of Conduct Inconsistent with Competition

Conduct that may potentially warrant the imposition of a mitigation measure includes the categories described in Section 2.4 above. The thresholds listed in sSection 3.1.1 below shall be used to identify substantial departures from competitive conduct indicative of an absence of workable competition.

***

3.1.1.1 Reference Levels

(a) For purposes of establishing reference levels, bid segments shall be defined as follows:

1. the capacity of each generation resource shall be divided into 10 equal Energy bid segments between its minimum (Pmin) and maximum (Pmax) operating point.

A reference level for each bid segment shall be calculated each day for peak and off-peak periods on the basis of the following methods, listed in the following order of preference subject to the existence of sufficient data, where sufficient data means at least one data point per time period (peak or off-peak) for the bid segment. Peak periods shall be the periods Monday through Saturday from Hour Ending 0700 through Hour Ending 2200, excluding holidays. Off-Peak periods are all other hours.

1. Excluding proxy and mitigated bids, the accepted bid, or the lower of the mean or the median of a resource's accepted bids if such a resource has more than one accepted bid in competitive periods over the previous 90 days for peak and off-peak periods, adjusted for monthly changes in fuel prices using the proxy figure for natural gas prices posted on the ISO Home Page. Accepted and justified bids above the applicable soft cap, as set forth in Section 28.1.2 of this Tariff, will be included in the calculation of reference prices.
2. If the resource is a gas-fired unit that does not have significant energy limitations, the unit's default Energy Bid determined monthly as set forth in Section 511.5 (based on the incremental heat rate submitted to the ISO, adjusted for

gas prices, and the variable O&M cost on file with the ISO, or the default O&M cost of $6/MWh).

3. For non gas-fired units and gas-fired units that have significant energy limitations, a level determined in consultation with the Market Participant submitting the bid or bids at issue, provided such consultation has occurred prior to the occurrence of the conduct being examined by the ISO, and provided the Market Participant has provided sufficient data on a unit' s energy limitations and operating costs (opportunity cost for energy limited resources) in accordance with specifications provided by the ISO.
4. The mean of the Economic Market Clearing Prices for the units' relevant location (zZone or node commensurate with the pricing granularity in effect) during the lowest-priced 25 percent of the hours that the unit was dispatched or scheduled over the previous 90 days for peak and off-peak periods, adjusted for changes in fuel prices; or
5. If sufficient data do not exist to calculate a reference level on the basis of the first, second, or fourth methods and the third method is not applicable or an attempt to determine a reference level in consultation with a Market Participant has

not been successful, the ISO shall determine a reference level on the basis of:

i. the ISO's estimated costs of an Electric Facility, taking into account available operating costs data, opportunity cost, and appropriate input from the Market Participant, and the best information available to the ISO; or

ii. an appropriate average of competitive bids of one or more similar Electric Facilities.

(b) The reference levels ($/MWh bid price) for the different bid segments of each resource (or import bid curve of a Scheduling Coordinator at a Scheduling Point) shall be made monotonically non-decreasing by the ISO by proceeding from the lowest MW bid segment moving through each higher MW bid segment. The reference level of each succeeding bid segment shall be the higher of the reference level of the preceding bid segment or the reference level determined according to paragraph (a) above.

3.2 Material Price Effects

3.2.1 Market Impact Thresholds

In order to avoid unnecessary intervention in the ISO Market, Mitigation Measures for economic withholding shall not be imposed unless conduct identified as specified above causes or contributes to a material change in one or more of the ISO ~~m~~Market~~ _c~~Clearing ~~p~~Prices

(MCPs). Initially, the thresholds to be used by the ISO to determine a material price effect shall be as follows:

For Energy Bids to be Dispatched as Imbalance Energy through the RTD Software: the lower of an increase of 200 percent or $50 per MWh in the projected Hourly Ex Post Price at any location (zZone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff.

For Energy Bids to be Dispatched out of economic merit order to manage Intra-Zonal Congestion: if the price of the bid is $50/MWh or 200 percent greater than the Dispatch Interval Ex Post Price at that location (zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff.

Accepted and justified bids above the applicable soft cap, as set forth in Section 28.1.2 of this Tariff, will not be eligible to set the Market Clearing Price. Such bids shall be included in the Market Impact test, however, and, for purposes of this test only, shall be assumed to be eligible to set the Market Clearing Price.

3.2.2 Price Impact Analysis

3.2.2.1 Bids to be Dispatched as Imbalance Energy.

The ISO shall determine the effect on prices of questioned conduct through automated computer modeling and -analytical methods. An Automatic Mitigation Procedure (AMP) shall identify bids that have exceeded the conduct thresholds and shall compute the change in projected Hourly Ex Post Prices as a result of simultaneously setting all such bids to their Reference Levels. If a change in the projected Hourly Ex Post Price exceeds the Impact

threshold stated in Section 3.2.1, those bids would be kept mitigated at their default bid levels as specified in Section 4.2.2 below.

3.2.2.2 Bids to be Dispatched out of economic merit order to manage Intra-Zonal Congestion. If the price of the bid is $50/MWh or 200 percent greater than the Dispatch Interval Ex Post Price at that location (~~z~~Zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff, the bid price shall be mitigated to the reference price and the Scheduling Coordinator for that resource shall be paid the greater of the reference price or the relevant Dispatch Interval Ex Post Price. Bids mitigated in accordance with this ~~s~~Section 3.2.2.2 shall not set the Dispatch Interval Ex Post Price.

3.2.3 Section 205 Filings

In addition, the ISO shall make a filing under Section 205 of the Federal Power Act with FERC~~the Commission~~ seeking authorization to apply an appropriate mitigation measure to conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in ~~s~~Section 3.1.1 above, unless the ISO determines, from information provided by the Market Participant or Parties that would be subject to mitigation or other information available to the ISO that the conduct is attributable to legitimate competitive market forces or incentives. The following are examples of conduct that are deemed to depart significantly from the conduct that would be expected under competitive market conditions:

(1) bids that vary with unit output in a way that is unrelated to the known performance characteristics of the unit, or

(2) bids that vary over time in a manner that appears unrelated to the change in the unit's performance or to changes in the supply environment that would induce additional risk or other adverse shifts in the cost basis.

The conducts listed above are intended to be examples rather than a comprehensive list.

3.3 Consultation with a Market Participant

If a Market Participant anticipates submitting bids in an ISO ~~m~~Market administered by the ISO that will exceed the thresholds specified in Section 3.1 above for identifying conduct inconsistent with competition, the Market Participant may contact the ISO to provide an explanation of any legitimate basis for any such changes in the Market Participant's bids. If a Market Participant's explanation of the reasons for its bidding indicates to the satisfaction of the ISO, that the questioned conduct is consistent with competitive behavior, no further action will be taken. Upon request, the ISO shall also consult with a Market Participant with respect to the information and analysis used to determine reference levels under Section 3.1.1~~2~~ above for that Market Participant.

***

4.2.2 Implementation

(a) If the criteria contained in Section 3 are met, the ISO may substitute a default bid for a bid submitted for an Electric Facility. The default bid shall establish a maximum value for each component of the submitted bid, equal to a reference level for that component determined as specified in Section 3.1.1 above.

(b) The Mitigation Measures will be applied to 1) all incremental bids submitted to the ~~R~~real-~~T~~time Imbalance Energy ~~M~~market during the pre-dispatch process prior to the ~~R~~real-~~T~~time Imbalance Energy ~~M~~market based on the projected ~~R~~real-time MCPs that are computed during this process; and 2) to the Day-Ahead and the Hour-Ahead Energy markets when these markets are made operational.

(c) An Electric Facility subject to a default bid shall be paid the MCP applicable to the output from the facility. Accordingly, a default bid shall not limit the price that a facility may receive unless the default bid determines the MCP applicable to that facility.

(d) The ISO shall not use a default bid to determine revised MCPs for periods prior to the imposition of the default bid, except as may be specifically authorized by FERC~~the Commission~~.

(e) The Mitigation Measures shall not be applied to Energy ~~b~~Bids projected to be Dispatched as Imbalance Energy through the RTD Software in the hours in which all Zonal Ex Post Prices are projected to be below $91.87/MWh. If the ~~z~~Zonal Dispatch Interval Ex Post Price is projected to be above $91.87/MWh in

any ISO ~~z~~Zone, the Mitigation Measures shall be applied to all bids, except those from System Resources, in all ISO ~~z~~Zones. The ISO will apply Mitigation Measures to all bids taken out of merit order to address Intra-Zonal Congestion.

(f) The Mitigation Measures shall not be applied to bids below $25/MWh.

(g) The posting of the MCP may be delayed if necessary for the completion of automated mitigation procedures.

(h) Bids not mitigated under these Mitigation Measures shall remain subject to mitigation by other procedures specified in the ISO Tariff as may be appropriate.

4.3 Sanctions for Physical Withholding

The ISO may report a Market Participant the ISO believes to have engaged in physical withholding, including providing the ISO false information regarding the derating or outage of an Electric Facility, to the Federal Energy Regulatory Commission in accordance with Section 2.3.3.9.5 of the ISO Tariff. In addition, a Market Participant that fails to operate a Generating Unit in conformance with ISO ~~d~~Dispatch ~~i~~Instructions shall be subject to the penalties set forth in Section 11.2.4.1.2 of the ISO Tariff.

***

OUTAGE COORDINATION PROTOCOL (OCP)

***

OCP 1.1.2 ISO Outage Coordination Office

The ISO Outage Coordination Office will be operational Monday through Friday, except holidays, and will accept, schedule, and approve or deny Maintenance Outage requests as necessary for the reliable operation of the ISO Controlled Grid. The Outage Coordination Office is located in Folsom ~~and Alhambra~~. Each office and the areas of responsibility of that office are detailed in the most recent version of the applicable ISO Operating Procedures, which are posted on the ISO Home Page.

***

OCP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meaning set opposite them:

"Final Approval" means a statement of consent by the ISO Control Center to initiate a scheduled Outage.

~~**"ISO Home Page"** means the ISO internet home page at http://www.caiso.com or such other internet address as the ISO shall publish from time to time.~~

***

OCP 2.2.1 Long-Range Planning Program

By October 15 of each year, each Generator will provide the ISO in writing with a proposed Outage schedule for each of its Generating Units (including its Reliability Must-Run Units) and System Units for the following calendar year. The following information is required for each Generating Unit:

(a) the Generating Unit name and Location Code;

(b) the MW capacity unavailable;

(c) the scheduled start and finish date for each Outage; and

(d) where there is a possibility of flexibility, the earliest start date and the latest finish date, along with the actual duration of the ~~o~~Outage once it commences.

***

SCHEDULES AND BIDS PROTOCOL

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***

SCHEDULES AND BIDS PROTOCOL (SBP)

***

SBP 1.2.2 **[Not used]~~Special Definitions for this Protocol~~**

~~In this Protocol, the following words and expressions shall have the meanings set opposite them:~~

~~**"Existing Rights"** as defined in Section 2.4.4.1.1 of the ISO Tariff,~~

~~**"Converted Rights"** as defined in Section 2.4.4.2.1 of the ISO Tariff shall have the same meanings where used in this Protocol.~~

***

SBP 2.1.1 **Generation Section of a Balanced Schedule and Adjustment Bid Data**

The Generation section of a Balanced Schedule will include the following information for each Generating Unit:

(a) SC's ID code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) name of Generating Unit scheduled;

(d) type of Schedule: Preferred or Revised (refer to the SP for details);

(e) priority type, if applicable, to the Settlement Period (use OTHER if scheduling the use of Existing Contract rights or RLB_MUST_RUN) for Reliability Must-Run Generation;

(f) contract reference number for Reliability Must-Run Generation;

(g) transmission loss self-provision flag (LOSS CMP FLG): "Yes" indicates that Dispatch Instructions provided to the Generating Unit will include ~~t~~Transmission ~~l~~Losses associated with the unit's Final Hour-Ahead Schedule as determined by the relevant GMM;

(h) Congestion Management flag – "Yes" indicates that any Adjustment Bid submitted under item (l) below should be used in the Day-Ahead or Hour-Ahead ~~m~~Market;

(i) publish Adjustment Bid flag, which will not be functional on the ISO Operations Date. In the future, "Yes" will indicate that the SC wishes the ISO to publish its Adjustment Bids;

(j) Generating Unit ramp rate in MW/minute;

(k) hourly scheduled Generating Unit output in MWh (the ISO will multiply these values by the hourly Generation Meter Multipliers), including any zero values, for each Settlement Period of the Trading Day (in the case of a Day-Ahead Schedule) and for the relevant Settlement Period (in the case of an Hour-Ahead Schedule); and

(l) the MW and $/MWh values for each Generating Unit for which an Adjustment Bid is being submitted consistent with SBP 4.

***

SBP 2.1.3 External Import/Export Section of a Balanced Schedule and Adjustment Bid Data

The external import/export section of a Balanced Schedule will include the following information for each import or export:

(a) SC's ID code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) Scheduling Point (the name);

(d) type of Schedule: Preferred or Revised (refer to the SP for details);

(e) interchange ID (the name of the selling entity, the buying entity, and a numeric identifier);

(f) Energy type – firm (FIRM), non-firm (NFRM) or dynamic (DYN) or Wheeling (WHEEL);

(g) external Control Area ID;

(h) priority type, if applicable, to the Settlement Period (use OTHER if scheduling the use of Existing Contract rights or RLB_MUST_RUN for Reliability Must-Run Generation);

(i) contract reference number for Reliability Must-Run Generation or Existing Contract (or set of interdependent Existing Contracts);

(j) contract type – transmission (TRNS), Energy (ENGY) or both (TR_EN);

(k) Schedule ID (NERC ID number);

(l) Congestion Management flag - "Yes" indicates that any Adjustment Bid submitted for an external import/export in item (q) below should be used;

(m) publish Adjustment Bid flag, which will not be functional on the ISO Operations Date. In the future, "Yes" will indicate that the SC wishes the ISO to publish its Adjustment Bids;

(n) complete WSECC tag;

(o) hourly scheduled external imports/exports in MWh (the ISO will multiply these values by the hourly Generation Meter Multipliers), including any zero values, for each Settlement Period of the Trading Day (in the case of a Day-Ahead Schedule) and for the relevant Settlement Period (in the case of an Hour-Ahead Schedule) and with external imports into the ISO Controlled Grid reported as negative quantities and external exports from the ISO Controlled Grid reported as positive quantities;

(p) the MW and $/MWh values for each external import/export for which an Adjustment Bid is being submitted consistent with SBP 4; and

(q) for dynamically scheduled imports only, the transmission loss self-provision flag (LOSS_CMP_FLG): "Yes" indicates that Dispatch Instructions provided to the resource will include tTransmission lLosses associated with the resource's Final Hour-Ahead Schedule as determined by the relevant GMM.

***

SBP 2.1.6 Contract Usage Template Associated with a Balanced Schedule that Includes the Use of Existing Contract Rights or Firm Transmission Rights

The contract usage template can be submitted the day prior to the Trading Day, as set forth in the timing requirements of the SP. The contract usage template can be submitted seven days in advance. However, the contract usage template will not be validated till the trade day. Each contract usage template must include the following

information, in compliance with the ISO Data Templates and Validation Rules document which contains the format for submission of contract usage templates:

(a) SC's ID code:

(b) Type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) From Zone (must be different than "to Zone"), is the Zone in which all sources specified in the contract usage template must be located;

(d) To Zone (must be different than "from Zone"), is the Zone in which all sinks specified in the contract usage template must be located;

(e) Contract reference number for each Inter-Zonal Interface for which transmission capacity has been reserved under Existing Contract or Firm Transmission Right. Up to four contract reference numbers can be specified in this field, delimited by commas, for either Existing Contract usage or Firm Transmission Right usage, but not for both (i.e. Existing Contract rights and Firm Transmission Rights cannot be used together in linking sources and sinks on contract usage template). If the use of multiple Inter-Zonal Interfaces are being scheduled, the contract reference numbers must represent a contiguous string of contracts rights from one Zone to the next (although the contract reference numbers need not be listed in any particular order since they will be arranged by the ISO's scheduling program to connect the "from Zone" to "to Zone");

(f) Usage ID (a unique identifier that allows a SC to submit multiple usages for a given Inter-Zonal Interface);

(g) Contract usage, in hourly scheduled MW, for the 24 hours of the Trading Day (for Generators, contract usage can be either positive or negative [i.e., for pumps]; for loads, contract usage must be positive; for external imports and ~~I~~inter-Scheduling Coordinator ~~T~~trade imports, contract usage must be negative; for external exports, contract usage must be positive). Each contract usage amount must be less than or equal to the amount of Existing Contract rights specified by the relevant Participating Transmission Owner(s) of Firm Transmission Rights, whichever the case may be. Additionally, any Adjustment Bids that may also be submitted for any particular resource (source or sink) that is also identified on a contract usage template must not overlap the contract usages specified for a particular resource in a contract usage template;

(h) Priority usage, relative to all contract usages specified in a SC's Balanced Schedule, as expressed on a scale of one to ten (with 1 having least priority and 10 having highest priority). For Existing ~~Transmission~~ Contracts, this priority will be used to adjust usage quantities when scheduled usages exceed the reserved existing transmissions reservations; and

(i) Sources or sinks, of hourly scheduled MWH (in the case of Energy usages) or MW (in the case of Ancillary Services usages), specified on the contract usage template must be balanced (except for Ancillary Services which need not be specified with sinks). Each Energy schedule or Ancillary Service bid or self-provided schedule associated with a particular source or sink must have an hourly usage schedule that is greater than or equal to the amounts specified on contract usage templates. The source/sink section of a contract usage template will include the following information (up to five combinations of sources and sinks can be specified on a single contract usage template if an SC is submitting the templates in accordance with SBP 7.2(a), or up to 20 combinations of sources and sinks if an SC is submitting the templates in accordance with SBP 7.2(b) or SBP 7.2(c));

(1) Type of resource – ~~g~~Generation (GEN), load (LOAD), interchange (INTRCHNGE) or ~~i~~nter-Scheduling Coordinator ~~T~~trade (INTER_SC);

(2) Resource_ID – generator_ID, load_ID, tie_point or trading SC;

(3) Resource_ID2 (required only for individual interchange schedules and ~~i~~nter-Scheduling Coordinator ~~T~~trades);

(4) Energy type – firm (FIRM), non-firm (NFIRM), ~~w~~Wheeling (WHEEL), dynamic (DYN), Energy (ENGY), Spinning Reserve (CSPN), Non-Spinning Reserve (CNSPN) or Replacement Reserve (CRPLC); and

(5) Hourly scheduled Energy or Ancillary Service, utilizing the same sign convention as set forth in (g) above.

***

SBP 2.2.2 Stage Two Validation

During stage two validation, Schedules will be checked to determine whether each SC's aggregate Generation and external imports (adjusted for Transmission Losses) and Inter-Scheduling Coordinator Energy Trades (whether purchases or sales) equals the SC's aggregate Demand ~~f~~Forecast, including external exports. The SC must take into account the applicable Generation Meter Multipliers (GMMs) as described in the SP. The SC will be notified if the counterpart trade to any Inter-Scheduling Coordinator Ancillary Service Trade has not been submitted, or is infeasible (i.e. if both SCs are selling or both are buying). Mismatches in Inter-Scheduling Coordinator Ancillary Service Trades shall be adjusted to be equal to the amount specified by the selling SC. This validation is performed in accordance with the timing requirement described in the SP. An SC can also check whether its Schedules will pass the ISO's stage two validation by manually initiating validation of its Preferred Schedules or Revised Schedules, as

described in the SP, at any time prior to the deadline for submission of Preferred Schedules or Revised Schedules (as the case may be). It is the SC's responsibility to perform such checks, if desired. The SC will be notified immediately through WEnet of any validation errors. For each error detected, an error message will be generated by the ISO in the SC's notification screen which will specify the nature of the error. If the ISO detects a mismatch in Inter-Scheduling Coordinator Trades, the ISO will notify both SCs of the mismatch in Energy quantity and/or location. The SC can then look at the notification messages to review the detailed list of errors, make changes, and resubmit the Schedule if it is still within the timing requirements of the SP. The SC is also notified of successful validation via WEnet.

***

SBP 3.3.1 Data Requirements

The Responsible PTO with respect to an Existing Contract or set of interdependent Existing Contracts is required to submit to the ISO, in accordance with the timing requirements of SBP 3.3.5, the instructions that are necessary to implement the exercise of the Existing Rights in accordance with the ISO Tariff. These instructions will be submitted to the ISO electronically, by the Responsible PTO, utilizing a form provided by the ISO in a format similar to the one set out in the Appendix to this Protocol (the "Transmission Rights/Curtailment Instructions Template"). The instructions will include the following information at a minimum and such other information as the ISO may reasonably require to enable it to carry out its functions under the ISO Tariff and ISO Protocols (the letters below correspond with the letters of the instructions template in the Appendix to this Protocol):

(a) a unique contract reference number (Existing Contract reference number that will be assigned by the ISO and communicated to the Responsible PTO on the completed instruction and that references a single Existing Contract or a set of interdependent Existing Contracts; the provisions of SBP 3.4 will apply to the validation of scheduled uses of Existing Contract transmission rights);

(b) whether the instruction can be exercised independent of the ISO's day-to-day involvement (Yes/No);

(c) name of an operational single point of contact for instructions and a 24-hour a day telephone number for the Responsible PTO;

(d) name(s) and number(s) of Existing Contract(s);

(e) path name(s) and location(s) (described in terms of the Zones in which the point(s) of receipt and point(s) of delivery are located);

(f) names of the party(ies) to the Existing Contract(s);

(g) SC ID code: the ID number of the SC who will submit Schedules which make use of the Existing Contract(s) for the party(ies) indicated in (f);

(h) type(s) of rights, by rights holder, by Existing Rights;

(i) type(s) of service, by rights holder, by Existing Contract (firm, conditional firm, or non-firm), with priorities for firm and conditional firm transmission services indicated in Schedules using Adjustment Bids as described in the SP;

(j) amount of transmission service, by rights holder, by Existing Contract expressed in MW;

(k) for Day-Ahead scheduling purposes, the time of the day preceding the Trading Day at which the SC submits Schedules to the ISO referencing the Existing Contract(s) identified in the instructions;

(l) for Hour-Ahead or real-time scheduling purposes, the number of minutes prior to the start of the Settlement Period of delivery at which the SC may submit Schedule adjustments to the ISO regarding the Existing Rights under the Existing Contract(s) identified in the instructions;

(m) whether or not real-time modifications to Schedules associated with Existing Rights are allowed at any time during the Settlement Period;

(n) Service period(s) of the Existing Contract(s);

(o) any special procedures which would require curtailments to be implemented by the ISO in any manner different than that specified in SBP 3.3.2. Any such instructions submitted to the ISO must be clear, unambiguous, and not require the ISO to make any judgments or interpretations as to the meaning, intent, results, or purpose of the curtailment procedures or the Existing Contract (otherwise, they will not be accepted by the ISO); and

(p) any special procedures relating to curtailments during emergency conditions. Any such instructions submitted to the ISO must be clear, unambiguous, and not require the ISO to make any judgments or interpretations as to the meaning, intent, results, or purpose of the curtailment procedures or the Existing Contract (otherwise, they will not be accepted by the ISO).

***

SBP 5.1.1.2 Regulation: External Imports

Each SC desiring to self-provide Regulation or to participate in the ISO's Regulation auction will submit the following information for each

relevant external import for each Settlement Period of the relevant Trading Day:

(a) type of schedule: (Regulation Ancillary Service);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Scheduling Point (the name)

(e) interchange ID code (the name of the selling entity, buying entity and a numeric identifier);

(f) external Control Area ID;

(g) Schedule ID (NERC ID number);

(h) complete WSECC tag;

(i) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(j) in the case of Existing contracts, the applicable contract reference number;

(k) upward and downward range of System Resource capacity over which the System Resource is offering to provide Regulation;

(l) System Resource operating limits (high and low MW);

(m) ramp rate (MW/minute); and

(n) bid price for Regulation capacity ($/MW).

***

SBP 5.1.2.2 Spinning Reserve: External Imports/Exports

Each SC desiring to bid or self-provide Spinning Reserve will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Scheduling Point (the name);

(e) interchange ID code (the name of the selling entity, buying entity and a numeric identifier);

(f) external Control Area ID;

(g) Schedule ID (NERC ID number);

(h) complete WSECC tag;

(i) preferred bid flag, which must be set to "NO", indicating a self-provided schedule, until such time as the ISO's scheduling system is able to support Ancillary Services bids from external imports/exports;

(j) export flag, a "YES" indicates an external export and a "NO" indicates an external import;

(k) In the case of Existing Contracts, the applicable contract reference number;

(l) Spinning Reserve capacity (MW);

(m) ramp rate (MW/minute); and

(n) bid price for Spinning Reserve capacity ($/MW).

***

SBP 5.1.3.3 Non-Spinning Reserve: External Imports/Exports

Each SC desiring to bid or self-provide Non-Spinning Reserve will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Non-Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Scheduling Point (the name);

(e) interchange ID code (the name of the selling entity, buying entity and a numeric identifier);

(f) external Control Area ID;

(g) Schedule ID (NERC ID number);

(h) complete WSECC tag;

(i) preferred bid flag, which must be set to "NO", indicating a self-provided schedule;

(j) export flag, a "YES" indicates an external export and a "NO" indicates an external import;

(k) In the case of Existing Contracts, the applicable contract reference number;

(l) time to synchronize following notification (less than ten (10) minutes mandatory);

(m) Non-Spinning Reserve capacity (MW);

(n) ramp rate (MW/minute); and

(o) bid price for Non-Spinning Reserve capacity.

***

SBP 5.1.4.3 Replacement Reserve: External Imports

Each SC desiring to bid or self-provide Replacement Reserve will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Replacement Reserve Ancillary Service (ANC_SRVC) or Revised Replacement Reserve Ancillary Service (REVISED_ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Scheduling Point (the name);

(e) interchange ID code (the name of the selling entity, buying entity and a numeric identifier);

(f) external Control Area ID;

(g) Schedule ID (NERC ID number);

(h) complete WSECC tag;

(i) preferred bid flag, which must be set to "NO", indicating a self-provided schedule, until such time as the ISO's scheduling system is able to support Ancillary Services bids from external imports;

(j) in the case of Existing Contracts, the applicable contract reference number;

(k) time to synchronize following notification (less than sixty (60) minutes mandatory);

(l) Replacement Reserve capacity (MW);

(m) ramp rate (MW/minute); and

(n) bid price for Replacement Reserve capacity ($/MW).

***

SBP 5.3 Buy Back of Ancillary Services

A Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace such capacity to the extent scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or to the extent the Ancillary Service associated with a Generating Unit, Curtailable Demand, or System Resouruce successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead ~~m~~Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduing Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replaced Ancillary Service shall be at the Market Clearing Price in the Hour-Ahead Market for the same Settlement Period for the Ancillary Service capacity concerned.

***

SBP 6.1.1 Generation Section of Energy Bid Data

Each SC offering Spinning, Non-Spinning, or Replacement Reserve, or Supplemental Energy to the ISO will submit the following information for each Generating Unit for each Settlement Period:

(a) SC's ID code;

(b) name of Generating Unit;

(c) Generating Unit operating limits (high and low MW);

(d) Generating Unit operational ramp rate in MW/minute;

(e) Generating Unit startup time function in minutes;

(f) Generating Unit startup cost function in $/start;

(g) Generating Unit ~~m~~Minimum ~~l~~Load ~~c~~Cost in $/hr; and

(h) the MW and $/MWh values for each Generating Unit for which a Supplemental Energy bid is being submitted consistent with this SBP 6.

A Physical Scheduling Plant shall be treated as a single Generating Unit for Supplemental Energy bid purposes.

***

SBP 6.1.3 External Import Section of Energy Bid Data

Each SC offering Spinning, Non-Spinning, or Replacement Reserve, or Supplemental Energy to the ISO will submit the following information for each external import for each Settlement Period;

(a) SC's ID code;
(b) name of Scheduling Point;
(c) interchange ID (the name of the selling entity, the buying entity, and a numeric identifier);
(d) external Control Area ID;
(e) Schedule ID (NERC ID number);
(f) complete WSECC tag;
(g) operational ramp rate (MW/minute); and
(h) the MW and $/MWh values for each external import for which a Supplemental Energy bid is being submitted consistent with this SBP 6; and
(i) minimum block of hours that bid must be dispatched; and
(j) Flag indicating the bid must is capable available for intra-hour rRedispatch. If this flag is set to no then the bid is indicating that the bid must be pre-dispatched and not re-dispatched during the real-time operating hour.

***

SBP 6.7 Format and Validation of Startup and Shutdown Costs

For a Generating Unit, the submitted startup cost expressed in dollars ($) as a function of down time expressed in minutes (min) must be a staircase function with up to 10 segments defined by a set of 1 to 10 down time and startup cost pairs. The startup cost is the cost incurred to start the resource if it is offline longer than the corresponding down time. The last segment will represent the cost to start the resource from cold startup and will extend to infinity. The submitted startup cost function shall be validated as follows:

- The first down time must be 0 min.
- The down time entries must match exactly (in number, sequence, and value) the corresponding down time breakpoints of the cost-based startup cost function, as registered in the Master File for the relevant resource.
- The startup cost for each segment must not be negative and must not exceed the startup cost of the corresponding segment of the cost-based startup cost function, as registered in the Master File for the relevant resource. For gas-fired resources, the cost-based startup cost function shall be derived from the startup fuel function, as registered in the Master File for the relevant resource, and the applicable gas price index as approved by FERC.

- The startup cost function must be strictly monotonically increasing, i.e., the startup cost must increase as down time increases.

For Curtailable Demand, a single shutdown cost in $ is the cost incurred to shut down the resource after receiving a ~~d~~Dispatch ~~i~~Instruction. The submitted shutdown cost must not be negative.

SBP 6.8 Format and Validation of Minimum Load Costs

For a Generating Unit, the submitted ~~m~~Minimum ~~l~~Load ~~c~~Cost expressed in dollars per hour ($/hr) is the cost incurred for operating the unit at minimum load. The submitted ~~m~~Minimum ~~l~~Load ~~c~~Cost must not be negative and must not exceed the cost-based ~~m~~Minimum ~~l~~Load ~~c~~Cost, as registered in the Master File for the relevant resource. For gas-fired resources, the cost-based ~~m~~Minimum ~~l~~Load ~~c~~Cost shall be derived pursuant to Section 5.11.6.1.2.

For Curtailable Demand, the submitted ~~m~~Minimum ~~l~~Load ~~c~~Cost ($/hr) is the cost incurred while operating the resource at reduced consumption after receiving a Dispatch Instruction. The submitted ~~m~~Minimum ~~l~~Load ~~c~~Cost must not be negative.

***

SBP APPENDIX

TRANSMISSION RIGHTS/CURTAILMENT INSTRUCTIONS TEMPLATE

Transmission Rights/Curtailment Instructions Template

(a) Contract Ref #	(b) Ind Imp	(c) Contact Person
[a single number]	[yes/no]	[phone number] [name(s)]

Submitted By PTO: _____

Date Received By ISO: _____

Date Accepted By ISO: _____

(d) Contract Name(s)/Number(s)	(e) Path Name(s) and Location(s)			(f) Party	(g) SC ID	(h) ER/NCR	(i)(j) Types and Amounts of Transmission Service			(k) DA	(l) HA	(m) RT	(n) Service Period	
	Path Name(s)	POR Zone	POD Zone				Firm /1/	CF /1/	N-F	(hour-ending)	(minutes)	(yes/no)	Beginning	Ending
[name/number 1]		[zone name]	[zone name]	[party 1]	[sc id 1]	[er]	[MW]	[MW]	[MW]	[1400]	[30]	[yes]	[hh/dd/mm/yy]	[hh/dd/mm/yy]
				[party 2]	[sc id 2]	[ncr]	["]	["]	["]		[n/a]	[no]	["]	["]
				[party n]	[sc id n]	[er]	["]	["]	["]		[20]	[yes]	["]	["]
[name/number 2]		[zone name]	[zone name]	[party 1]	[sc id 1]	[er]	[MW]	[MW]	[MW]	[1400]	[20]	[yes]	["]	["]
				[party 2]	[sc id 2]	[ncr]	["]	["]	["]		[n/a]	[no]	["]	["]
				[party n]	[sc id n]	[er]	["]	["]	["]		[20]	[yes]	["]	["]
[name/number n]		[zone name]	[zone name]	[party 1]	[sc id 1]	[er]	[MW]	[MW]	[MW]	[1500]	[20]	[yes]	["]	["]
				[party 2]	[sc id 2]	[ncr]	["]	["]	["]		[n/a]	[no]	["]	["]
				[party n]	[sc id n]	[er]	["]	["]	["]		[20]	[yes]	["]	["]

(o) Non-Emergency Curtailments

[If other than pro rata, attach spreadsheet for ISO to use in allocating curtailments to rights holders between the indicated ~~z~~Zones. Otherwise, indicate "pro rata" here.]

(p) Emergency Curtailments

[Describe special procedures/requirements here. Indicate "N/A" if none.]

/1/ Priorities for firm and conditional firm transmission service are indicated in Schedules using Adjustment Bids as described in the SP.

SCHEDULING COORDINATOR APPLICATION PROTOCOL (SCAP)

***

SCAP 1.2.2 Special Terms for this Protocol

In this Protocol, the following words and expressions shall have the meaning set forth below:

"Electronic Data Interchange" (EDI) means the routine exchange of business documented on electronic media such as purchase orders, invoices and remittance. The format of the data is based on an industry-approved format such as those published by the ANSI ASC X12 committee.

"ISO Application File Template" means all information (administrative, financial and technical) pertaining to Scheduling Coordinators which must be maintained in a current form by the ISO and the Scheduling Coordinator.

~~**"ISO Home Page"** means the ISO Internet home page at http://www.caiso.com/iso or such other address, as the ISO shall publish from time to time.~~

~~**"ISO Metered Entity"** means (a) any one of the following entities that is directly connected to the ISO Controlled Grid: (i) Generator other than a Generator that sells all of its Energy (excluding any Energy consumed by auxiliary load equipment electrically connected to that Generator at the same point), and Ancillary Services to the UDC in whose Service Area it is located; (ii) an Eligible Customer; or (iii) an End User other than an End User that purchases all of its Energy from the UDC in whose Service Area it is located; and (b) any one of the following entities: (i) a Participating Generator; or (ii) a Participating TO in relation to its Tie Point Meters with other TOs or Control Areas.~~

~~**"SC Applicant"** means an entity, which has submitted or is contemplating submitting an application to become a SC.~~

"SC Customer" means a customer of the SC Applicant or a Scheduling Coordinator for whom the SC provides services relevant to the ISO Controlled Grid.

~~**"SC Metered Entity"** means a Generator, Eligible Customer or End User that is not an ISO Metered Entity~~

"Validation, Estimation and Editing" (VEE) applies to ~~m~~Meter ~~d~~Data directly acquired by the ISO. Validation is the process of checking the data to ensure that it is contiguous, within pre-defined limits and has not been flagged by the meter. Estimation and Editing is the process of replacing or making complete ~~m~~Meter ~~d~~Data by using data from redundant meters, schedules, PMS or, if necessary, statistical estimation.

"Value Added Network" (VAN) means a data communications service provider that provides, stores and forwards electronic data

delivery services within its network and to subscribers on other VANs. The data is mostly EDI type messages.

***

SCAP 2.2 ISO Information

The ISO will provide the following information, in its most current form, on the ISO Home Page. Upon a request by a SC Applicant, the ISO will send the following information by mail:

(a) the SC Application Form (including the ISO Application File Template which is Appendix C);

(b) the ISO Tariff and ISO Protocols;

(c) pro forma ~~m~~Meter ~~s~~Service ~~a~~Agreements and ~~i~~Interim ~~b~~Black ~~s~~Start ~~a~~Agreement;

(d) historical ISO charges (Note: prior to January 2, 1998, estimated ISO charges) including, but not limited to, charges for purchased Ancillary Services, ISO Grid Management ~~c~~Charge, ISO Grid Operations ~~c~~Charge, Imbalance Energy market charges, and Usage ~~c~~Charges to assist the SC Applicant in determining the ISO Security Amount the SC Applicant must provide; and

(e) a pro forma letter of understanding for payment for SC Applicants with Approved Credit Ratings, guarantee, letter of credit and escrow agreement for the ISO Security Amount, all of which will be in a form acceptable to the ISO.

***

SCAP 2.5 Notice of Receipt

Within 3 ~~b~~Business ~~d~~Days of receiving the application, the ISO will send a written notification to the SC Applicant that it has received the application and the non-refundable fee.

***

SCAP 2.6.2 SC Applicant's Obligation for Contracts

An SC Applicant must certify that it is duly authorized to represent the Generators and Loads, which are its SC Customers and must further certify that:

(a) represented Generators have entered into ~~p~~Participating ~~g~~Generator ~~a~~Agreements with the ISO;

(b) represented UDCs have entered into UDC agreements with the ISO;

(c) represented ISO Metered Entities have entered into ~~m~~Meter ~~s~~Service ~~a~~Agreements with the ISO;

(d) none of the Wholesale Customers it will represent are ineligible for wholesale transmission service pursuant to the provisions of the FPA Section 212(h); and

(e) each End-Use Customer it will represent is eligible for Direct Access service pursuant to an established program approved by the California Public Utility~~y~~ies Commission or a Local Regulatory Authority.

***

SCAP 4.1 SC Applicant's Acceptance

If the ISO accepts the application, the SC Applicant must return an executed SC Agreement, ~~m~~Meter ~~s~~Service ~~a~~Agreements, ~~i~~Interim ~~b~~Black ~~s~~Start ~~a~~Agreements and letter of credit, guarantee or escrow agreement for the ISO Security Amount, as applicable.

***

SCAP 6 FINAL CERTIFICATION OF SC APPLICANT

The SC Applicant will become a Scheduling Coordinator when:

(a) its application has been accepted;

(b) it has entered into an SC Agreement, ~~m~~Meter ~~s~~Service ~~a~~Agreements and ~~i~~Interim ~~b~~Black ~~s~~Start ~~a~~Agreements, if applicable, with the ISO;

(c) the SC Applicant has met the financial requirements of ISO Tariff Section 2.2.3.2; and

(d) the SC Applicant has fulfilled all technical/operational requirements of ISO Tariff Section 2.2.7.1, SCAP 5.1 and the ISO Application File Template.

The ISO will not certify an SC Applicant as a Scheduling Coordinator until the SC Applicant has completed all the above referenced requirements to the ISO's satisfaction, at least 14 days before the commencement of service.

***

SCAP 7.1.2 Obligation to Report a Change in Credit Rating

The SC has an ongoing obligation to inform the ISO within 3 ~~b~~Business ~~d~~Days if its Approved Credit Rating has been reduced below the ISO requirements.

***

SCAP APPENDIX A

SCHEDULING COORDINATOR APPLICATION FORM

***

2.2 Information for SC Metered Entities, which are End Users or Eligible Customers, must be kept in a standard business format based on generally accepted accounting principals. The ISO shall have the right to inspect and audit a Scheduling Coordinator' s accounts and files relating to its SC Metered Entities after giving two ~~b~~Business ~~d~~Days notice in writing.

***

V. Third Party Contractual Requirements

5.1 The SC Applicant confirms that all of its SC Customers which are located within the ISO Controlled Grid and which should execute agreements with the ISO have entered into or will enter into, prior to the certification of the SC Applicant, all required agreements with the ISO to enable them to meet the requirements of the ISO Tariff: (yes / no).

(a) Represented Generators have signed ~~p~~Participating ~~g~~Generator ~~a~~Agreements: (yes / no).

(b) Represented UDCs have signed UDC Operating Agreements and ~~m~~Meter ~~s~~Service ~~a~~Agreements: (yes / no).

(c) Represented ISO Metered Entities have signed ~~m~~Meter ~~s~~Service ~~a~~Agreements: (yes / no).

(d) Wholesale Customers it will represent have warranted to the SC Applicant that they are eligible for wholesale transmission service pursuant to the provisions of the FPA Section 212(h): (yes / no).

(e) Each End-Use Customer it will represent which requests Direct Access service has warranted to the SC Applicant that the End-Use Customer is eligible for such service: (yes / no).

***

VI. Additional Information and Obligations

***

6.2 Subject to the ISO Tariff, the SC Applicant agrees to promptly report to the ISO within seven (7) ~~b~~Business ~~d~~Days or earlier any changes regarding the information provided by it referred to in the SCAP and in the application with the exception of the security requirement data referred to in Part III of SCAP Appendix A which must be updated within three (3) ~~b~~Business ~~d~~Days. The Scheduling Coordinator shall be responsible if a failure to submit revised technical data more promptly extends the period during which schedules are rejected by the ISO.

***

6.4 SC Applicant agrees to promptly execute and return the SC Agreement, ~~m~~Meter ~~s~~Service ~~a~~Agreements, ~~i~~Interim ~~b~~Black ~~s~~Start ~~a~~Agreements, software licensing agreement, letter of understanding, letter of credit, guarantee, escrow agreement, as applicable, and Fed-Wire System bank account number, after receiving its application approval letter from the ISO.

***

SCAP APPENDIX B

Procedures for Changes or Additions to

Scheduling Coordinator's (SC's) Information

***

The SC must notify the ISO of any change to the information that it has previously submitted to the ISO, or any additional information, at least three ~~b~~Business ~~d~~Days before the change will take effect.

The ISO will send a written acknowledgment of receipt of the SC's changes within three ~~b~~Business ~~d~~Days of receipt. The receipt shall be sent to the address on file with the ISO or the address specified in the notice of change received by the ISO.

***

SCHEDULING PROTOCOL

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SCHEDULING PROTOCOL (SP)

SP 1 OBJECTIVES, DEFINITIONS AND SCOPE

SP 1.1 Objectives

The objectives of this Protocol are:

(a) to process the scheduling input data (submitted to the ISO under the Ancillary Service Requirements Protocol (ASRP), the Demand Forecasting Protocol (DFP), and the Schedules and Bids Protocol (SBP)) in order to develop Final Schedules for the Day-Ahead and Hour-Ahead Markets (real-time management of the ISO Controlled Grid is addressed in the Dispatch Protocol (DP));

(b) to provide for the scheduling of the use of Firm Transmission Rights and use of transmission service rights under Existing Contracts;

(c) to assist the ISO in purchasing Ancillary Services; and

(d) to manage Congestion.

***

SP 1.2.2 **[Not used]~~Special Definitions for this Protocol~~**

~~In this Protocol, the following words and expressions shall have the meanings set opposite them:~~

~~**"ISO Home Page"** means the ISO internet home page at http://www.caiso.com/iso or such other internet address as the ISO shall publish from time to time.~~

SP 1.2.3 **Rules of Interpretation**

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

(e) References to time are references to the prevailing Pacific time.

***

SP 3 **Time Lines**

(a) Consistent with Sections 2.2.12.1 and 2.5.2.2 of the ISO Tariff, the ISO may implement any temporary variation or waiver of timing requirements contained in this SP (including the omission of any step) if any of the following criteria are met:

(i) the ISO receives Schedules that require delay in performing Day-Ahead Market or Hour-Ahead Market evaluations, such as in the case of the ISO receiving Inter-Scheduling Coordinator Energy Trades that do not balance;

(ii) the ISO requires additional time to fulfill its responsibilities pursuant to Section 2.2.2 of the ISO Tariff;

(iii) problems with data or the processing of data cause a delay in receiving or issuing Schedules or publishing information on the WEnet;

(iv) problems with telecommunications or computing infrastructure cause a delay in receiving or issuing Schedules or publishing information on the WEnet; or

(v) such waiver or variation of timing requirements is reasonably necessary to preserve System Reliability, prevent an

imminent or threatened System Emergency or to retain Operational Control over the ISO Controlled Grid during an actual System Emergency.

(b) If the ISO temporarily implements a waiver or variation of such timing requirements (including the omission of any step) consistent with Section 2.2.12.1 of the ISO Tariff and SP 3(a), the ISO will publish the following information on WEnet as soon as practicable:

(i) the exact timing requirements affected;

(ii) details of any substituted timing requirements;

(iii) an estimate of the period for which this waiver or variation will apply; and

(iv) reasons for the temporary waiver or variation.

(c) If, despite the variation of any time requirement or the omission of any step, the ISO either fails to receive sufficient Schedules to operate the Day-Ahead Market or is unable to perform Congestion Management in the Day-Ahead Market, the ISO may abort the Day-Ahead Market and require all Schedules to be submitted, and Congestion Management to be performed, in the Hour-Ahead Market.

(d) If, despite the variation of any time requirement or omission of any step, the ISO either fails to receive sufficient Schedules to operate the Hour-Ahead Market or is unable to perform Congestion Management in the Hour-Ahead Market, the ISO may abort the Hour-Ahead Market and function in real time.

(e) The incorporation of the scheduling of the use of rights under Existing Contracts into the ISO's Day-Ahead, Hour-Ahead and real-time processes is additionally described in SP 7 and in the SBP.

SP 3.1 Balanced Schedules

SP 3.1.1 Types of Balanced Schedules

A Schedule shall be treated as a Balanced Schedule when the SC's aggregate Generation and external imports (adjusted for Transmission Losses) and Inter-Scheduling Coordinator Energy Trades (whether purchases or sales), equal the SC's aggregate Demand ~~f~~Forecast, including external exports, with respect to all entities for which the SC schedules. On an interim basis, the ISO may assist SCs in matching Inter-Scheduling Coordinator Energy Trades.

***

SP 3.1.4 Suggested Adjusted Schedules

If the sum of SCs' Preferred Schedules would cause Congestion across any Inter-Zonal Interface, the ISO shall issue Suggested Adjusted Schedules to all SCs in the Day-Ahead Market only. These Suggested Adjusted Schedules will not apply to uses of transmission owned by ~~n~~Non-

pParticipating ~~transmission owner~~TOs nor to uses of Existing Rights. A modification flag, set by the ISO, will indicate whether the scheduled output in a Settlement Period has been modified as a result of Congestion Management. The ISO will publish as public information, via the WEnet, estimated Usage Charges for Energy transfers between Zones.

***

SP 3.2.1.1 **By 5:00 am~~Two Hours Before Close of the PX Day-Ahead Market~~, One Day Ahead**

By no later than 5:00 am on the day before~~two hours before the close of the PX Day-Ahead Market on the day ahead of~~ the Trading Day, the ISO will notify SCs of the Energy Requirements from any Reliability Must-Run Units which the ISO requires to run in the Trading Day, except in those instances where a Reliability Must-Run Unit requires more than one day's notice, in which case the ISO may notify the applicable SC more than one day in advance of the Trading Day;

SP 3.2.1.2 **By 6:00 am~~One Hour Before Close of the PX Day-Ahead Market~~, One Day Ahead**

By no later than 6:00 am on the day before~~one hour before the close of the PX Day-Ahead Market on the day prior to~~ the Trading Day, SCs that have been notified that a Reliability Must-Run Unit is required to run in the Trading Day will inform the ISO, with regard to each hour for which the ISO has provided such notice, whether the RMR Owner will take payment from the market or under the RMR Contract.

***

SP 3.2.3 **By 6:30 am, One Day Ahead**

By 6:30 am on the day ahead of the Trading Day (for example, by 6:30 am on Tuesday for the Wednesday Trading Day) and for each Settlement Period of the Trading Day: the ISO will provide to UDCs, via WEnet, the sum of the SCs' Direct Access Demand fForecasts by UDC Service Area; and

***

SP 3.2.6 **By 10:00 am, One Day Ahead**

SP 3.2.6.1 **Actions by SCs and the ISO**

By 10:00 am on the day ahead of the Trading Day (for example, by 10:00 am on Tuesday for the Wednesday Trading Day) and for each Settlement Period of that Trading Day (see SP 3.2.6.2 for information on the pre-validation performed at ten (10) minutes prior to the 10:00 am deadline):

(a) SCs will submit their Preferred Day-Ahead Schedules to the ISO in accordance with the SBP;

(b) SCs will submit, as part of their Preferred Day-Ahead Schedules, their Adjustment Bids, if any, to the ISO in accordance with the SBP;

(c) SCs will submit their Ancillary Services bids, if any, to the ISO in accordance with the SBP and SP 9;

(d) SCs will submit their schedules for self-provided Ancillary Services, if any, to the ISO in accordance with the SBP and SP 9;

(e) the ISO will validate (in accordance with the SBP) all SC submitted Preferred Day-Ahead Schedules for Energy and Adjustment Bids and may assist SCs to resolve mismatches in scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades in accordance with the procedure described in SP 3.2.6.4;

(f) the ISO will validate (in accordance with the SBP) all SC submitted schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which were part of their Preferred Day-Ahead Schedules;

(g) the ISO will validate (in accordance with the SBP) all contract usage templates received from SCs for scheduled uses of Existing Contract rights and Firm Transmission Rights;

(h) the ISO will validate that all SC submitted Preferred Day-Ahead Schedules are compatible with the RMR requirements of which SCs were notified for that Trading Day and with the SCs' elected options for delivering the required Energy;

(i) the ISO will start the first iteration of Inter-Zonal Congestion Management process as described in SP 10; and

(j) the ISO will start the Ancillary Services bid evaluation process as described in SP 9;

***

SP 3.2.6.3 Invalidation

Except with respect to invalidated contract usage associated with Existing Contract rights or Firm Transmission Rights, invalidation of the submittal for any Settlement Period results in rejection of the submittal for that Settlement Period. SCs will be notified of any invalid contract usage via an invalidated contract usage template issued, via the WEnet, by the ISO. Invalidation of contract usage will not cause the rejection of the SC's submittal; instead, invalid contract usage will be treated as new firm uses of ISO transmission service without the priorities and protections afforded the scheduled use of Existing Contract rights and Firm Transmission Rights. During the initial operations of the ISO, the ISO may assist SCs to resolve mismatches in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades contained in their Preferred Schedules in accordance with SP 3.2.6.4. Except with respect to contract usage templates (for which SCs can check

whether or not their submittal will pass the ISO's validation checks between 9:00 am and 10:00 am), SCs may check at any time prior to 10:00 am whether or not their submittal will pass the ISO's validation checks at 10:00 am. It is the responsibility of the SCs to perform such checks since Preferred Day-Ahead Schedules, Adjustment Bids, Schedules of self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which are invalidated cannot be resubmitted after 10:00 am for the Day-Ahead Market, except that, during the initial period of ISO operations, the ISO will allow resubmission of Preferred Schedules which have mismatches in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades. The ISO will immediately communicate the results of each SC's 10:00 am validation to that SC via WEnet. If the usage or sum of the usages associated with an Existing ~~Transmission~~ Contract results in the contract being over-scheduled, the usages will be adjusted such that a usage in excess of the Existing ~~T~~Contract rights will be considered a ~~N~~new ~~F~~firm ~~U~~use (NFU) and will be exposed to Congestion charges.

***

SP 3.2.8.3 Invalidation

Except with respect to invalidated contract usage associated with Existing Contract rights or Firm Transmission Rights, invalidation of the submittal for any Settlement Period results in rejection of the submittal for that Settlement Period. SCs will be notified of any invalid contract usage via an invalidated contract usage template issued, via the WEnet, by the ISO. Invalidation of contract usage will not cause the rejection of the SC's submittal; instead, invalid contract usage will be treated as new firm uses of ISO transmission service without the priorities and protections afforded the scheduled use of Existing Contract rights and Firm Transmission Rights. During the initial operations of the ISO, the ISO may assist SCs to resolve mismatches in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades in accordance with 3.2.8.4. Except with respect to contract usage templates, SCs may check at any time prior to 12:00 noon whether or not their submittal will pass the ISO's validation checks (which are undertaken at 12:00 noon). It is the responsibility of the SCs to perform such checks since Revised Day-Ahead Schedules, Adjustment Bids, schedules of self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which are invalidated cannot be resubmitted after 12:00 noon for the Day-Ahead Market, except that during the initial period of operations, the ISO will allow resubmission of Schedules to resolve mismatches in the scheduled quantities and locations for Inter-Scheduling Coordinator Energy Trades. The ISO will immediately communicate the results of each SC's 12:00 noon validation to that SC via WEnet. If the usage or sum of the usages associated with an Existing ~~Transmission~~ Contract results in the contract being over-scheduled, the usages will be adjusted such that a usage in excess of the Existing ~~T~~Contract rights will be considered a ~~N~~new ~~F~~firm ~~U~~use (NFU) and will be exposed to Congestion charges.

***

SP 3.2.10 By 1:30 pm, Day Ahead

By 1:30 pm on the day ahead of the Trading Day (for example, by 1:30 pm on Tuesday for the Wednesday Trading Day) and for each Settlement Period of the Trading Day the ISO will publish, via WEnet, an updated forecast of system Demands.

SP 3.2.11 Between 1:00 p.m. and 10:00 p.m.

If, at any time after 1:00 p.m. and before 10:00 p.m. of the day prior to the Trading Day, the ISO determines that it requires Ancillary Services in addition to those provided through the Final Day-Ahead Schedules issued under SP 3.2.9, it may procure such additional Ancillary Services by providing to SCs, via WEnet, amended schedules for Ancillary Services that had been bid in the Day-Ahead Market but were not previously selected in the Final Day-Ahead Schedules, and have not been previously withdrawn. The ISO shall select such Ancillary Services in price merit order (and in the relevant ~~z~~Zone if the ISO is procuring Ancillary Services on a ~~z~~Zonal basis). Such amended schedules shall be provided to the SCs no later than 10:00 p.m. of the day prior to the Trading Day.

***

SP 3.3.1.1 Actions by SCs and the ISO

(a) SCs will submit their Preferred Hour-Ahead Schedules to the ISO in accordance with the SBP;

(b) SCs will submit, as part of their Preferred Hour-Ahead Schedules, their Adjustment Bids, if any, to the ISO in accordance with the SBP;

(c) SCs will submit their Ancillary Services bids, if any, to the ISO in accordance with the SBP and SP 9;

(d) SCs will submit their Schedules for self-provided Ancillary Services and Inter-Scheduling Coordinator Ancillary Service Trades, if any, to the ISO in accordance with the SBP and SP 9;

(e) the ISO will validate (in accordance with the SBP) all SC submitted Preferred Hour-Ahead Schedules for Energy and Adjustment Bids;

(f) SCs will submit contract usage templates for scheduled uses of Existing Contract ~~R~~rights and Firm Transmission Rights in accordance with the Hour-Ahead Market schedule, including usage template changes needed in response to line derations;

(g) the ISO will validate (in accordance with the SBP) all contract usage templates received from SCs for scheduled uses of Existing Contract rights and Firm Transmission Rights;

(h) the ISO will validate (in accordance with the SBP) all SC submitted Schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which were part of their Preferred Hour-Ahead Schedules;

(i) the ISO will start the Inter-Zonal Congestion Management process as described in SP 10;

(j) the ISO will start the Ancillary Services bid evaluation process as described in SP 9; and

(k) the ISO will validate that all SC submitted Preferred Hour-Ahead Schedules are compatible with the RMR requirements of which SCs were notified for that Trading Day and with the SCs' elected options for delivering the required Energy.

***

SP 3.3.1.3 Invalidation

Except with respect to invalidated contract usage associated with Existing Contract rights or Firm Transmission Rights, invalidation of the submittal results in rejection of the submittal. SCs will be notified of any invalid contract usage via an invalidated contract usage template issued, via the WEnet, by the ISO. Invalidation of contract usage will not cause the rejection of the SC's submittal; instead, invalid contract usage will be treated as new firm uses of ISO transmission service without the priorities and protections afforded the scheduled use of Existing Contract rights and Firm Transmission Rights. SCs may check at any time prior to two hours and fifteen minutes ahead of the relevant Settlement Period whether or not their submittals will pass the ISO's validation checks (which are undertaken at two hours and fifteen minutes ahead of the Settlement Period). It is the responsibility of SCs to perform such checks since Preferred Hour-Ahead Schedules, Adjustment Bids, schedules of self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades and Ancillary Services bids which are invalidated cannot be resubmitted for the Hour-Ahead Market after two hours and fifteen minutes ahead of the relevant Settlement Period. The ISO will immediately communicate the results of each SC's two hour and fifteen minute ahead validation to that SC via WEnet. If the usage or sum of the usages associated with an Existing ~~Transmission~~ Contract results in the contract being over-scheduled, the usages will be adjusted such that a usage in excess of the Existing ~~T~~Contract rights will be considered a ~~N~~new ~~F~~firm ~~U~~use (NFU) and will be exposed to Congestion charges.

SP 3.3.2 By One Hour Ahead

By one hour ahead of the Settlement Period (for example, by 11:00 am for the Settlement Period starting at 12:00 noon [or hour ending 1300]) and in respect of that Settlement Period:

(a) The ISO will use the SC's Final Day-Ahead Schedule, without any Day-Ahead Adjustment Bids or Day-Ahead Ancillary Service bids, in the event the SC's Preferred Hour-Ahead Schedule fails validation.

If a SC desires to submit an Hour-Ahead Schedule that is different than its Final Day-Ahead Schedule the SC must submit the Hour-Ahead Schedule including the addition or removal of any resources (i.e., for those resources to be removed, a zero value for the hourly MW quantity) in its Final Day-Ahead Schedule that are to be added, or that are not to be included, in the Hour-Ahead Schedule. A SC's failure to add or remove such resources will cause the Hour-Ahead Schedule to be unbalanced, and rejected as such in the ISO's validation process.

(b) the ISO will complete, if necessary, the Inter-Zonal Congestion Management process described in SP 10;

(c) the ISO will provide, via WEnet, Final Hour-Ahead Schedules for Energy to the ISO's real-time dispatchers for use under the DP and to all SCs which, depending on the existence of Inter-Zonal Congestion, could be:

(i) the Preferred Hour-Ahead Schedules (when no Congestion was found at one hour ahead); or

(ii) modified Preferred Hour-Ahead Schedules for those SCs which had their Preferred Hour-Ahead Schedules for Energy modified for Inter-Zonal Congestion; and

(d) the ISO will publish on WEnet the Hour-Ahead Usage Charge rate (in $/MWh of scheduled flow) for Energy transfers between Zones, if any;

(e) the ISO will provide, via WEnet, as part of the Final Hour-Ahead Schedules, schedules for Ancillary Services to the ISO's real-time dispatchers for use under the DP and to the SCs which either:

(i) submitted Ancillary Services bids and which, as a result, have been selected to supply Ancillary Services; or

(ii) specified Inter-Scheduling Coordinator Ancillary Service Trades, or submitted schedules to self-provide Ancillary Services and which schedules have been validated by the ISO; and

(f) each SC will provide the ISO, via a form and by means of communication specified by the ISO, resource specific information for all Generating Units and Curtailable Demands constituting its System Unit, if any, scheduled or bid into the ISO's Day-Ahead Market and/or Hour-Ahead Market for Ancillary Services.

(g) the ISO will coordinate with adjacent Control Areas on the net schedules between the ISO Control Area and such other Control Areas. If the ISO and the operator of an adjacent Control Area have different records with respect to the net schedules, individual SC intertie schedules will be examined. If the other Control Area operator's records were in error, no changes will be required by the ISO or SCs. If the other Control Area operator's records are determined to be correct, the ISO will notify the affected SC. The ISO will manually adjust the affected SC's schedule to conform with the other Control Area operator's net schedule, in real time, and the

affected SC will be responsible for managing any resulting Energy imbalance.

***

SP 4.2 Generator Meter Multipliers (GMMs)

SP 4.2.1 Derivation of GMMs

(a) The ISO will utilize the Power Flow Model to determine the GMMs which will be used to allocate, to each Generating Unit and external import, scheduled and Ex Post Transmission Losses.

(b) For each Settlement Period, the GMMs will be first calculated before SCs submit Day-Ahead Preferred Schedules. Prior to the time when SCs are required to submit their Day-Ahead Preferred Schedules, the ISO will forecast the total Control Area Demand. This forecast, along with the ISO forecast of Generation and Demand patterns throughout the ISO Control Area, will be used to develop estimated GMMs for each Generating Unit and each external import. The ISO will calculate and publish (in accordance with SP 3.2.1) GMMs for each Settlement Period to reflect different expected Generation and Demand patterns and expected operations and maintenance requirements, such as line Outages, which could affect Transmission Loss determination and allocation.

(c) The ISO will utilize the real-time Power Flow Model to calculate Ex Post GMMs to allocate Ex Post Transmission Losses to each Generating Unit and each external import. This run of the Power Flow Model will use metered Generation and Demand. Any difference between scheduled and Ex Post Transmission Losses will be considered as an Imbalance Energy deviation and will be purchased or sold in the Real Time Market at the ~~BEEP~~Settlement Interval Ex Post Price.

***

SP 5.3 Scheduling of Reliability Must-Run Generation

The ISO will notify SCs of any Reliability Must-Run Units which the ISO requires to run during a Trading Day no later than 5:00 am on the day before ~~two hours before the close of the PX Day-Ahead Market for~~ that Trading Day, as described in SP 3.2.1.1.

***

SP 7.5.1 Inter-Control Area Changes to Schedules that Rely on Existing Rights

Changes to Schedules that occur during the ISO's real-time processes that involve changes to ISO Control Area imports or exports with other Control Areas (that is, inter-Control Area changes to Schedules) will be allowed and will be recorded by the ISO based upon notification received from the SC representing the holder of the Existing Rights. The ISO must be notified of any such changes to external import/export schedules. The ISO will receive notification of real-time changes to external import/export schedules, by telephone, from the SC representing the holder of the Existing Rights. The timing and content of any such notification must be consistent with the instructions previously submitted to the ISO by the Responsible PTO in accordance with the SBP. The ISO will manually adjust the SC's schedule to conform with the other Control Area's net schedule in real time, and the notifying SC will be responsible for and manage any resulting Energy imbalance. These Imbalance Energy deviations will be priced and accounted to the SC representing the holder of Existing Rights in accordance with the SABP.

***

SP 8 OVERGENERATION MANAGEMENT

SP 8.1 Real-Time Overgeneration Management

Overgeneration management in real time will be conducted in accordance with the DP.

***

SP 9.3 Scheduling Ancillary Services Resources

(a) SCs are allowed to self-provide all or a portion of the following Ancillary Services to satisfy their obligations to the ISO:

(i) Regulation;

(ii) Spinning Reserve;

(iii) Non-Spinning Reserve; and

(iv) Replacement Reserve.

(b) The ISO will reduce the quantity of Ancillary Services it competitively procures by the corresponding amount of the Ancillary Services that SCs self-provide.

(c) The ISO shall prepare supplier schedules for Ancillary Services (both self-provided and purchased by the ISO) for the Day-Ahead Market and the Hour-Ahead Market.

(d) The Ancillary Services schedules shall contain the information set out in the SBP for each Settlement Period of the following Trading Day in the case of the Day-Ahead ~~s~~Schedules or for a specific Settlement Period in the case of Hour-Ahead ~~s~~Schedules.

(e) Once the ISO has given SCs notice of the Day-Ahead and Hour-Ahead ~~s~~Schedules, these schedules represent binding commitments made in the reserve markets between the ISO and the SCs concerned. A Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace such capacity to the extent scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or to the extent the Ancillary Service associated with a Generating Unit, Curtailable Demand, or System Resource successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduling Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replacement shall be at the Market Clearing Price in the Hour-Ahead Market for the Ancillary Service for the Settlement Period concerned for the Zone in which the Generating Unit or other resources on behalf of which the Scheduling Coordinator buys back the capacity, are located. The ISO will purchase the Ancillary Service concerned from another Scheduling Coordinator in the Hour-Ahead Market in accordance with the provisions of the ISO Tariff.

(f) Any minimum Energy output associated with Regulation and Spinning Reserve services shall be the responsibility of the SC, as the ISO's auction does not compensate the SC for the minimum Energy output of its Generating Units or System Unit, if any, bidding to provide these services. Accordingly, the SCs shall adjust their Balanced Schedules to accommodate the minimum Energy outputs required by the Generating Units or System Units, if any, included in the Ancillary Services schedules.

(g) SCs providing one or more of the Ancillary Services cannot change the identification of the Generating Units System Units or external imports of System Resources, if any, or Curtailable Demands offered in the Day-Ahead Market, in the Hour-Ahead Market, or in the Real Time Market (except with respect to System Units, if any, in which case SCs are required to identify and disclose the resource specific information for all Generating Units and Curtailable Demands constituting the System Unit scheduled or bid into the ISO's Day-Ahead Market and Hour-Ahead Market as required in SP 3.3.2(e)).

***

SP 9.5.2 Regulation Price Determination

The price payable to SCs for Regulation made available for upward and downward movement in accordance with the ISO's Ancillary Services schedules will, for each Generating Unit, System Unit, and System Resource concerned, be the ~~z~~Zonal Market Clearing Price for Regulation calculated as follows:

$Pagc_{ijt} = MCP_{xt}$

where:

the ~~z~~Zonal Market Clearing Price (MCP_{xt}) for Regulation is the highest priced winning reservation bid of a Generating Unit, System Unit, or System Resource serving Demand in Zone X based on the reservation bid price (i.e., $MCP_{xt} = Max\ (CapRes_{ijt})$ in Zone X for Settlement Period t). In the absence of Inter-Zonal Congestion, the ~~z~~Zonal Market Clearing Prices will be equal.

***

SP 9.6.2 Spinning Reserves Price Determination

The price payable to SCs for Spinning Reserve made available in accordance with the ISO's Ancillary Services schedules shall, for each Generating Unit, System Unit or external import of a System Resource concerned, be the ~~z~~Zonal Market Clearing Price for Spinning Reserve calculated as follows:

$Psp_{ijt} = MCP_{xt}$

where:

the ~~z~~Zonal Market Clearing Price (MCP_{xt}) for Spinning Reserve is the highest priced winning reservation bid of a Generating Unit, System Unit or external import of a System Resource serving Demand in Zone X based on the reservation bid price (i.e., $MCP_{xt} = Max(CapRes_{ijt})$ in Zone *X* for Settlement Period t). In the absence of Inter-Zonal Congestion, the ~~z~~Zonal Market Clearing Prices will be equal.

SP 9.7 Non-Spinning Reserves Bid Evaluation and Pricing

SP 9.7.1 Non-Spinning Reserves Bid Evaluation

(a) Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units, Curtailable Demands and external imports of System Resources with the Non-Spinning Reserve bids which minimize the sum of the total Non-Spinning Reserve bids of the Generating Units, System Units, Curtailable Demands -and external imports of System Resources selected subject to two constraints:

(i) the sum of the selected amounts of Non-Spinning Reserve bid must be greater than or equal to the required amount of Non-Spinning Reserve; and

(ii) the amount of Non-Spinning Reserve bid for each Generating Unit, System Unit, or Curtailable Demand must be less than or equal to that Generating Unit's, System Unit's, ~~or~~ Curtailable Demand's, or external import's ramp rate (or time to interruption in the case of a Load offering Demand reduction) times the difference between 10 minutes and the time to synchronize in the case of a Generating Unit, or to interruption in the case of a Load.

(b) The total Non-Spinning Reserve bid for each Generating Unit, System Unit, Curtailable Demand or external import of a System Resource is calculated by multiplying the reserve reservation bid price by the amount of Non-Spinning Reserve bid. Subject to any locational requirements, the ISO will accept the winning Non-Spinning Reserve bids in accordance with the following criteria:

***

SP 9.7.2 Non-Spinning Reserves Price Determination

The price payable to SCs for Non-Spinning Reserve made available in accordance with the ISO's Ancillary Services schedules shall, for each Generating Unit, System Unit, Curtailable Demand ~~or~~ external import of a System Resource concerned, be the ~~z~~Zonal Market Clearing Price for Non-Spinning Reserve calculated as follows:

$Pnonsp_{ijt} = MCP_x$

where:

the ~~z~~Zonal Market Clearing Price (MCP_{xt}) for Non-Spinning Reserve is the highest priced winning reservation bid of a Generating Unit, System Unit, Curtailable Demand or external import of a System Resource serving Demand in Zone X based on the reservation bid (i.e., $MCP_{xt} = Max(CapRes_{ijt})$ in Zone *X* for Settlement Period t). In the absence of Inter-Zonal Congestion, the ~~z~~Zonal Market Clearing Prices will be equal.

SP 9.8 Replacement Reserves Bid Evaluation and Pricing

SP 9.8.1 Replacement Reserves Bid Evaluation

(a) Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units, Curtailable Demands and external imports of ~~a~~ System Resources with the Replacement Reserve bids which minimize the sum of the total Replacement Reserve bids of the Generating Units, System Units, Curtailable Demands and external imports of System Resources selected subject to two constraints:

(i) the sum of the selected amounts of Replacement Reserve bid must be greater than or equal to the required amount of Replacement Reserve; and

(ii) the amount of Replacement Reserve bid for each Generating Unit, System Unit, Curtailable Demand or external import of a System Resource must be less than or equal to that Generating Unit's, System Unit's, Curtailable Demand's or external import's ramp rate (or time to interruption in the case of a Load offering Demand reduction) times the difference between 60 minutes and the time to synchronize in the case of Generating Unit, or to interruption in the case of Load.

(b) The total Replacement Reserve bid for each Generating Unit, System Unit, Curtailable Demand or external import of a System Resource is calculated by multiplying the reserve reservation bid price by the amount of Replacement Reserve bid. Subject to any locational requirements, the ISO will select the winning Replacement Reserve bids in accordance with the following criteria:

***

SP 9.8.2 Replacement Reserves Price Determination

The price payable to SCs for Replacement Reserve made available in accordance with the ISO's Ancillary Services schedules shall, for each Generating Unit, System Unit, Curtailable Demand or external import of a System Resource concerned, be the ~~z~~Zonal Market Clearing Price for Replacement Reserve calculated as follows:

$Prepres_{ijt} = MCP_{xt}$

where:

the ~~z~~Zonal Market Clearing Price (MCP_{xt}) for Replacement Reserve is the highest priced winning reservation bid of a Generating Unit, System Unit, Curtailable Demand or external import of a System Resource serving Demand in Zone X based on the reservation bid price (i.e., MCP_{xt} = $Max(CapRes_{ijt})$ in Zone X for Settlement Period t). In the absence of Inter-Zonal Congestion, the ~~z~~Zonal Market Clearing Prices will be equal.

***

SP 10.2 Congestion Management Process

(a) Inter-Zonal Congestion Management will involve adjusting Schedules to remove potential violations of Inter-Zonal Interface ~~c~~Constraints, minimizing the ~~r~~Redispatch cost, as determined by the submitted Adjustment Bids that accompany the submitted Schedules. See the

SBP for a general description of the use of Adjustment Bids to establish priorities.

(b) Inter-Zonal Congestion Management will not involve arranging or modifying trades between SCs. Each SC's portfolio will be kept in balance (i.e., its Generation plus external imports, as adjusted for Transmission Losses, and Inter-Scheduling Coordinator Energy Trades (whether purchases or sales) will still match its Demand plus external exports) after the adjustments. Market Participants will have the opportunity to trade with one another and to revise their Schedules during the first Congestion Management iteration in the Day-Ahead Market, and between the Day-Ahead Market and Hour-Ahead Market.

(c) Inter-Zonal Congestion Management will also not involve the optimization of SC portfolios within Zones (where such apparently non-optimal Schedules are submitted by SCs). Adjustments to individual SC portfolios within a Zone will be either incremental (i.e., an increase in Generation and external imports and a decrease in Demand and external exports) or decremental (i.e., a decrease in Generation and external imports and an increase in Demand and external exports), but not both.

(d) If Adjustment Bids are exhausted before Congestion is eliminated, the remaining Schedules will be adjusted *pro rata* except for those uses of transmission service under Existing Contracts, which are curtailed in accordance with SP 7.3 and SP 7.4.

***

SP 11 CREATION OF THE REAL-TIME MERIT ORDER STACK

SP 11.1 Sources of Imbalance Energy

The following Energy Bids will be considered in the creation of the real-time merit order stack for Imbalance Energy:

(a) Supplemental Energy bids submitted in accordance with the SBP;

(b) Ancillary Services Energy ~~b~~Bids (except for Regulation) submitted for specific Ancillary Services in accordance with the SBP for those resources which have been selected in the ISO's Ancillary Services auction to supply such specific Ancillary Services; and

(c) Ancillary Services Energy ~~b~~Bids (except for Regulation) submitted for specific Ancillary Services in accordance with the SBP for those resources which SCs have elected to use to self-provide such specific Ancillary Services and for which the ISO has accepted such self-provision.

SP 11.2 Stacking of the Energy Bids

The sources of Imbalance Energy described in SP 11.1 will be arranged in order of increasing Energy ~~b~~Bid prices to create a merit order stack for use in accordance with the DP. This merit order stack will be arranged without

regard to the source of the Energy ~~b~~Bid except that Energy ~~b~~Bids associated with Spinning and Non-Spinning Reserve shall not be included in the merit order stack during normal operating conditions if the capacity associated with such bids has been designated as available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency. In the event of an unplanned Outage, a Contingency or threatened or actual System Emergency, all Energy ~~b~~Bids associated with Spinning and Non-Spinning Reserve may be included in the merit order stack. In the event of Inter-Zonal Congestion, separate merit order stacks will be created for each Zone. The information in the merit order stack shall be provided to the real-~~-~~time dispatcher through the RTD~~BEEP (Balancing Energy and Ex-Post Pricing)~~ Software.

Where, in any ~~BEEP~~Settlement Interval, the highest decremental Energy Bid in the merit order stack is higher than the lowest incremental Energy Bid, the ~~BEEP~~RTD Software will eliminate the Price Overlap by actually dispatching for all those incremental and decremental bids which fall within the overlap.

References to incremental Energy Bids include references to Demand reduction bids, and for the purpose of applying this algorithm a reduction in Demand shall be treated as an equivalent increase in Generation.

***

SETTLEMENT AND BILLING PROTOCOL (SABP)

***

SABP 1.2.2 **Special Definitions for this Protocol**

In this Protocol, the following words and expressions shall have the meanings set opposite them:

~~**"Black Start Generator"** means a Participating Generator in its capacity as party to an Interim Black Start Agreement with the ISO for the provision of Black Start Services, but shall exclude Participating Generators in their capacity as providers of Black Start services under their Reliability Must-Run Contracts.~~

"Day 0" means the Trading Day to which the Settlement Statement or sSettlement calculation refers. For example "Day 41" shall mean the 41st day after that Trading Day and similar expressions shall be construed accordingly.

"Fed-Wire" means the Federal Reserve Transfer System for electronic funds transfer.

"Interim Black Start Agreement" means an agreement entered into between the ISO and a Participating Generator (other than a Reliability Must-Run Agreement) for the provision by the Participating Generator of Black Start capability and Black Start Energy on an interim basis until the introduction by the ISO of its Black Start auction (or until terminated earlier by either party in accordance with its terms).

"ISO Surplus Account" means the account established by the ISO pursuant to SABP 6.5.

~~**"ISO Home Page"** means the ISO internet home page at http://www.caiso.com/iso or such other internet address as the ISO shall publish from time to time.~~

"Security" means the form of security provided by a Scheduling Coordinator pursuant to Section 2.2.3.2 of the ISO Tariff (i.e. letter of credit, guarantee or cash deposit) to secure its trading obligations.

"Trading Interval" means a Settlement Period as defined in the Master Definitions Supplement of the ISO Tariff.

**

SABP 1.3 **Scope**

SABP 1.3.1 **Scope of Application to Parties**

This Protocol (excluding Annex 1) applies to the ISO and to the following entities:

(a) Scheduling Coordinators;

(b) Participating TOs;

(c) Black Start Generators;

(d) Utility Distribution Companies, and

(e) Metered Subsystems.

The sSettlement, billing and payment process between the ISO, Scheduling Coordinators, Participating TOs, Black Start Generators, Utility Distribution Companies, and Metered Subsystems shall be in accordance with Sections 11.3 to 11.24 inclusive of the ISO Tariff. References in those Sections to Scheduling Coordinators shall also apply to Participating TOs which receive Settlement Statements from the ISO in relation to the transactions referred to in those Settlement Statements but excluding the transactions referred to in Annex 1. Notwithstanding SABP 1.2.3(a), references in Sections 11.3 to 11.24 inclusive of the ISO Tariff to Scheduling Coordinators, ISO Debtors and ISO Creditors shall also apply to Black Start Generators which receive Settlement Statements from the ISO in relation to transactions under their Interim Black Start Agreements.

Annex 1 of this Protocol applies to the ISO, Owners of Reliability Must-Run Units and Participating TOs in relation to the billing and payment of amounts due under Reliability Must-Run Contracts and recovery of such amounts by the ISO from Participating Utilities. The provisions of this Protocol shall not apply to Annex 1 unless otherwise specified.

***

SABP 2 OVERVIEW OF SETTLEMENT AND BILLING PROCESS

SABP 2.1 Settlement Software

The ISO sSettlement software shall be audited by an independent firm of auditors competent to carry out audits of such software to determine its consistency with this Protocol and the ISO Tariff. In any dispute regarding Settlement calculations, a certificate of such firm of auditors that the ISO software is consistent with the ISO Tariff shall be prima facie proof that the charges shown in a Settlement Statement have been calculated in a method consistent with the ISO Tariff and this Protocol. Nothing in this section will be deemed to establish the burden of proof with respect to Settlement calculations in any proceeding.

***

SABP 2.3.5 Update the Final Payments Calendar

If as a result of a tariff amendment approved by FERC the final ISO Payments Calendar developed in accordance with SABP 2.3.3 and 2.3.4 above is rendered inconsistent with the timing set forth in the tariff, the ISO shall update the final ISO Payments Calendar to make it consistent with the tariff as approved by FERC on the date on which the tariff amendment goes into effect. The ISO shall simultaneously send out a notice to ~~m~~Market ~~p~~Participants that the final ISO Payments Calendar has been revised.

***

SABP 3.1 **Description of Charges to be Settled**

The ISO shall, based on the Settlement Quality Meter Data it has received, or, if Settlement Quality Meter Data is not available, based on the best available information or estimate it has received, calculate the following:

(a) the amount due from each Scheduling Coordinator for its share for the relevant month of the seven components of the Grid Management Charge in accordance with the formula located in Appendix F, Schedule 1, Part A of this Tariff. These Charges shall accrue on a monthly basis.

(b) the amount due from each Scheduling Coordinator for the Grid Operations Charge in accordance with Appendix F, Schedule 2 of this Tariff. This charge shall accrue on a monthly basis.

(c) the amount due from and/or owed to each Scheduling Coordinator for the Charge for each Ancillary Service in accordance with Appendix C, for each of the Settlement Periods of Day 0.

(d) the amount due from and/or owed to each Scheduling Coordinator for Imbalance Energy in accordance with Appendix D, for each of the Settlement Periods of Day 0.

(e) the amount due from and/or owed to each Scheduling Coordinator for Usage Charges in accordance with Appendix E, for each of the Settlement Periods of Day 0.

(f) the amount due from each Scheduling Coordinator for Wheeling Out and Wheeling Through Charges and the amount owed to each Participating TO for these charges in accordance with Appendix F, for each of the Settlement Periods of Day 0.

(g) the amounts due from/to Scheduling Coordinators for Voltage Support (supplemental reactive power charges) for each of the Settlement Periods of Day 0 in accordance with Appendix G.

(h) the monthly charges due from/to Scheduling Coordinators for long-term Voltage Support provided by Owners of Reliability Must-Run Units in accordance with Appendix G.

(i) the amounts due from/to Scheduling Coordinators for the provision of Black Start Energy from Reliability Must-Run Units for each of the Settlement Periods of Day 0 in accordance with Appendix G.

(j) the amounts due from/to Black Start Generators for the provision of Black Start Energy for each of the Settlement Periods of Day 0 in accordance with Appendix G.

(k) the amount due from each UDC or MSS, or from a Scheduling Coordinator delivering Energy for the supply of Gross Load not directly connected to the facilities of a UDC or MSS, for the High Voltage Access Charge and Transition Charge in accordance with operating procedures posted on the ISO Home Page. These charges shall accrue on a monthly basis.

(l) the amounts due from Scheduling Coordinators for FERC Annual Charges.

All of the data, information, and estimates the ISO uses to calculate these amounts shall be subject to the auditing requirements of Section 10.5 of the ISO Tariff.

The ISO shall calculate these amounts using the software referred to in SABP 2.1 except in cases of system breakdown when it shall apply the procedures set out in SABP 9 (Emergency Procedures).

***

SABP 4.4.5 ISO Contact

If the ISO does not agree with the amount claimed or if it requires additional information, it shall make reasonable efforts (taking into account the time it received the notice of dispute and the complexity of the issue involved) to contact the relevant Scheduling Coordinator, Black Start Generator or Participating TO to resolve the issue before issuing the Final Settlement Statement. If it is not possible to contact the relevant party, the ISO shall issue the Final Settlement Statement without taking into account the dispute notice.

***

SABP 4.5 **Settlement Statement Re-runs**

SABP 4.5.1 **Notice**

If a Scheduling Coordinator, Black Start Generator or Participating TO, (having made reasonable efforts to resolve with the ISO any dispute relating to a Preliminary Settlement Statement pursuant to SABP 4.4) requires a Settlement Statement ~~r~~Re-run, it shall send at any time to the ISO Governing Board a notice in writing.

SABP 4.5.2 **ISO Tariff**

The provisions of Sections 11.6.3, 11.6.3.1, 11.6.3.2 and 11.6.3.3 of the ISO Tariff relating to Settlement Statement ~~r~~Re-runs shall apply to all Scheduling Coordinators, Black Start Generators or Participating TOs who require a Settlement ~~r~~Re-run in accordance with this SABP 4.5.

***

SABP 6.5.2 **Other Funds Used in the ISO Surplus Account.**

(a) Any amounts paid to the ISO in respect of penalties referred to in SABP 3.1.1 shall be credited to the Surplus Account.

(b) The funds referred to in SABP 6.5.2(a) pertaining to Penalties as provided in SABP 3.1.1 shall first be applied towards any expenses, loss or costs incurred by the ISO. Any excess will be credited to the Surplus Account pursuant to SABP 6.5.2(a).

(c) The funds referred to in SABP 6.5.2(a) pertaining to default Interest referred to in SABP 6.10.5 shall first be applied towards any unpaid creditor balances for the trade month in which the default Interest was assessed and second to any other unpaid creditor balances. Only after all unpaid creditor balances are satisfied in full will any excess funds pertaining to default Interest ~~-~~be credited to the Surplus Account pursuant to SABP 6.5.2(a).

***

SETTLEMENT AND BILLING PROTOCOL

APPENDIX B

GRID OPERATIONS CHARGE COMPUTATION

B 1 **Purpose of charge**

The Grid Operations Charge is a charge which recovers ~~r~~Redispatch costs incurred due to Intra-Zonal Congestion pursuant to Section 7.3.2 of the ISO Tariff. The Grid Operations Charge is paid by or charged to Scheduling Coordinators in order for the ISO to recover and properly redistribute the costs of adjusting the Balanced Schedules submitted by Scheduling Coordinators.

***

B 2.2 **Charges to Scheduling Coordinators with decremented schedules**

When it becomes necessary for the ISO to decrease the output of a Scheduling Coordinator's Generating Unit$_i$ or System Resource$_i$ in order to relieve Congestion within a Zone, the ISO will make a charge to the Scheduling Coordinator. The amount that the ISO will charge Scheduling Coordinator$_j$ for decreasing the output of Generating Unit$_i$ is the decremental reference price specified for the Scheduling Coordinator as determined in accordance with Section 7.2.6.1 multiplied by the quantity of Energy Dispatched. The amount that the ISO will charge Scheduling Coordinator$_j$ for decreasing the output of System Resource$_i$ is the price specified in the Scheduling Coordinator's Imbalance Energy ~~B~~bid for System Resource$_i$ multiplied by the quantity of Energy Dispatched. The formula for calculating the charge to Scheduling Coordinator$_j$ for each block$_b$ of Energy in its decremental reference price or Imbalance Energy bid in Trading Interval$_t$ is:

$$DEC_{bijt} = adjdec_{bijt} * \Delta dec_{bijt}$$

***

B 2.4 **Net ISO ~~r~~Redispatch costs**

The Trading Interval net ~~r~~Redispatch cost encountered by ISO to relieve Intra-Zonal Congestion is the sum of the amounts paid by the ISO to those Scheduling Coordinators whose Generation or System Resource was increased or Curtailable Demand was decreased during the Trading Interval less the sum of the amounts received by the ISO from those Scheduling Coordinators whose Generating Units or System

Resource were decreased during the Trading Interval. The fundamental formula for calculating the net rRedispatch cost is:

$$REDISP_{CONG_t} = \sum_j PayTI_{ijt} - \sum_j ChargeTI_{ijt}$$

Note that $REDISP_{CONGt}$ can be either positive or negative. This means that it is possible for the ISO to generate either a net cost or a net income, for any given Trading Interval. In the event the ISO does not make use of equal amounts of incremental and decremental dispatched MWHs, then the net rRedispatch cost becomes the sum of the amounts paid (or charged) by the ISO to those Scheduling Coordinators whose Generation or System Resource was increased (or decreased) or Curtailable Demand was decreased (or increased) during the Trading Interval less the sum of the amounts received by the ISO from Scheduling Coordinators through the Imbalance Energy Market.

B 2.5 Grid Operations Price

The grid operations price is the Trading Interval rate used by the ISO to apportion net Trading Interval rRedispatch costs to Scheduling Coordinators within the Zone with Intra-Zonal Congestion. The grid operations price is calculated using the following formula:

$$GOP_t = \frac{REDISP_{CONG_t}}{\sum_j QCharge_{jt} + \sum_j Export_{jt}}$$

B 2.6 Grid Operations Charge

The Grid Operations Charge is the vehicle by which the ISO recovers the net rRedispatch costs. It is allocated to each Scheduling Coordinator in proportion to the Scheduling Coordinator's Demand in the Zone with Intra-Zonal Congestion and Eexports from the Zone with Intra-Zonal Congestion. The formula for calculating the Grid Operations Charge for Scheduling Coordinator$_j$ in Trading Interval$_t$ is:

$$GOC_{jt} = GOP_t * \left(QCharge_{jt} + EXPORT_{jt}\right)$$

***

B 3.12 GOP_t - $/MWh

The Trading Interval grid operations price for Trading Interval$_t$ used by the ISO to recover the costs of rRedispatch for Intra-Zonal Congestion Management.

***

APPENDIX C

ANCILLARY SERVICES CHARGES COMPUTATION

C 1 Purpose of charges

The Ancillary Services ~~C~~charges reimburse the ISO for the costs of purchasing Ancillary Services in the Day-Ahead and Hour-Ahead Markets. Each Scheduling Coordinator that does not self-provide Ancillary Services must purchase these services from the ISO. The ISO will in turn purchase these Ancillary Services from Scheduling Coordinators in the markets. Ancillary Services purchased and resold by the ISO includes Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve. Any references in this Appendix C to the Ancillary Service "Regulation" shall be read as referring to "Regulation Up" or "Regulation Down".

This Appendix C also addresses the payments by ISO to Scheduling Coordinators for the Dispatch of energy from Dispatched Ancillary Services Units and for the Dispatch of Supplemental Energy in the Real Time Market. The ISO recovers the costs of ~~R~~real-~~T~~time Dispatch of such energy through the Imbalance Energy charges described in Appendix D of this Protocol.

The reference to a Scheduling Coordinator by Zone refers to the Demand of that Scheduling Coordinator which is located in the Zone. A Generation Unit, Load, or System Resource located in another Control Area is considered to be located in the Zone in which its contract path enters the ISO Controlled Grid.

The ISO will purchase Ancillary Services for each Trading Interval in both the Day-Ahead and Hour-Ahead Markets. Separate payments will be calculated for each service for each Trading Interval and in each market for each Generating Unit, Load and System Resource. The ISO will then calculate a total payment for each Scheduling Coordinator for each Trading Interval for each service for each Zone in each market for all the Generating Units, Loads and System Resources that the Scheduling Coordinator represents. The ISO will charge Scheduling Coordinators for Ancillary Services, other than for energy, which they purchase from the ISO by calculating and applying charges to each Scheduling Coordinator for each Trading Interval for each service in each Zone in each market.

The ISO will allocate the Ancillary Services capacity charges, for both the Day-Ahead Market and the Hour-Ahead Market, on a Zonal basis if the Day-Ahead Ancillary Services Market is procured on a Zonal basis. The ISO will allocate the Ancillary Services capacity charges, for both the Day-Ahead Market and the Hour-Ahead Market, on an ISO Control Area wide basis if the Day-Ahead Ancillary Services Market is defined on an ISO Control Area wide basis.

C 2 Fundamental formulas

C 2.1 ISO payments to Scheduling Coordinators

C 2.1.1 Day-Ahead Market

(a) Regulation. When the ISO purchases Regulation capacity in the Day-Ahead Market, Scheduling Coordinators for Generating Units that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit which provides Regulation capacity over a given Trading Interval will be the total quantity of Regulation capacity provided times the ~~z~~Zonal Market Clearing Price for that Trading Interval in that Zone. The required Regulation capacity is defined in the Ancillary Services Requirements Protocol. Regulation Up and Regulation Down payments shall be calculated separately. This payment for Scheduling Coordinator j for providing Regulation Up capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCUpPayDA_{ijxt} = AGCUpQDA_{ijxt} * PAGCUpDA_{xt}$$

This payment for Scheduling Coordinator j for providing Regulation Down capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCDownPayDA_{ijxt} = AGCDownQDA_{ijxt} * PAGCDownDA_{xt}$$

The total Regulation Up payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$AGCUpPayTotalDA_{jxt} = \sum_{i} AGCUpPayDA_{ijxt}$$

The total Regulation Down payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$AGCDownPayTotalDA_{jxt} = \sum_{i} AGCDownPayDA_{ijxt}$$

(b) Spinning Reserve. When ISO purchases Spinning Reserve capacity in the Day-Ahead Market. Scheduling Coordinators for Generating Units and System Resources that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit or System Resource which provides Spinning Reserve capacity over a given Trading Interval will be the total quantity of Spinning Reserve capacity provided times the ~~z~~Zonal Market Clearing Price for that Trading Interval in that Zone. The required Spinning Reserve capacity is defined in the Ancillary Services Requirements Protocol. This payment for Scheduling Coordinator j for providing Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$SpinPayDA_{ijxt} = SpinQDA_{ijxt} * PSpinDA_{xt}$$

The total Spinning Reserve payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$SpinPayTotalDA_{jxt} = \sum_{i} SpinPayDA_{ixt}$$

(c) Non-Spinning Reserve. When the ISO purchases Non-Spinning Reserve capacity in the Day-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Non-Spinning Reserve capacity over a given Trading Interval will be the total quantity of Non-Spinning Reserve capacity provided times the ~~z~~Zonal Market Clearing Price for that Trading Interval in that Zone. The required Non-Spinning Reserve capacity is defined in the Ancillary Services Requirements Protocol. This payment for Scheduling Coordinator j for providing Non-Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$NonSpinPayDA_{ijxt} = NonSpinQDA_{ijxt} * PNonSpinDA_{xt}$$

The total Non-Spinning Reserve payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$NonSpinPayTotalDA_{jxt} = \sum_{i} NonSpinPayDA_{ijxt}$$

(d) Replacement Reserve. When the ISO purchases Replacement Reserve capacity in the Day-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Replacement Reserve capacity over a given Trading Interval will be the total quantity of Replacement Reserve capacity provided times the ~~z~~Zonal Market Clearing Price for thatTrading Interval in that Zone. The required Replacement Reserve capacity is defined in the Ancillary Services Requirements Protocol. This payment for Scheduling Coordinator j for providing Replacement Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$ReplPayDA_{ijxt} = ReplQDA_{ijxt} * PReplDA_{xt}$$

The total Replacement Reserve payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$ReplPayTotalDA_{jxt} = \sum_{i} ReplPayDA_{ijxt}$$

C 2.1.2 Hour-Ahead Market

(a) Regulation. When the ISO purchases Regulation capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units that provide this capacity will receive payment for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit which provides Regulation capacity over the Trading Interval will be the total quantity of Regulation capacity provided times the ~~z~~Zonal Market Clearing Price for that Trading Interval in that Zone. The required Regulation capacity is defined in the Ancillary Services Requirements Protocol. Regulation Up and Regulation Down payments shall be calculated separately. This payment for

Scheduling Coordinator j for providing Regulation Up capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCUpPayHA_{ijxt} = AGCUpQIHA_{ijxt} * PAGCUpHA_{xt}$$

This payment for Scheduling Coordinator j for providing Regulation Down capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCDownPayHA_{ijxt} = AGCDownQIHA_{ijxt} * PAGCDownHA_{xt}$$

When a Scheduling Coordinator buys back, in the Hour-Ahead Market, Regulation capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Regulation capacity bought back times the ~~z~~Zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Regulation Up capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCUpReceiveHA_{ijxt} = AGCUpQDHA_{ijxt} * PAGCUpHA_{xt}$$

This payment to the ISO from Scheduling Coordinator j to buy back Regulation Down capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCDownReceiveHA_{ijxt} = AGCDownQDHA_{ijxt} * PAGCDownHA_{xt}$$

The total Regulation payment for the Trading Interval of the Hour-Ahead Market to each Scheduling Coordinator for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Regulation bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$AGCUpPayTotalHA_{jxt} = \sum_{i} AGCUpPayHA_{ijxt} - \sum_{i} AGCUpReceiveHA_{ijxt}$$

$$AGCDownPayTotalHA_{jxt} = \sum_{i} AGCDownPayHA_{ijxt} - \sum_{i} AGCDownReceiveHA_{ijxt}$$

(b) *Spinning Reserve*. When the ISO purchases Spinning Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units and System Resources that provide this capacity will receive payments for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit or System Resource which provides Spinning Reserve capacity

over the Trading Interval will be the total quantity of Spinning Reserve capacity provided times the zZonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$SpinPayHA_{ijxt} = SpinQIHA_{ijxt} * PSpinHA_{xt}$$

When a Scheduling Coordinator buys back in the Hour-Ahead Market Spinning Reserve capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Spinning Reserve capacity bought back times the zZonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$SpinReceiveHA_{ijxt} = SpinQDHA_{ijxt} * PSpinHA_{xt}$$

The total Spinning Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Spinning Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$SpinPayTotalHA_{jxt} = \sum_{i} SpinPayHA_{ijxt} - \sum_{i} SpinReceiveHA_{ijxt}$$

(c) Non-Spinning Reserve. When the ISO purchases Non-Spinning Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payment for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Non-Spinning Reserve capacity over the Trading Interval will be the total quantity of Non-Spinning Reserve capacity provided times the zZonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Non-Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$NonSpinPayHA_{ijxt} = NonSpinQIHA_{ijxt} * PNonSpinHA_{xt}$$

When a Scheduling Coordinator buys back in the Hour-Ahead Market Non-Spinning Reserve capacity which it sold to the ISO

in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Non-Spinning Reserve capacity bought back times the ~~z~~Zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Non-Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$NonSpinReceiveHA_{ijxt} = SpinQDHA_{ijxt} * PNonSpinHA_{xt}$$

The total Non-Spinning Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Non-Spinning Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$NonSpinPayTotalHA_{jxt} = \sum_{i} NonSpinPayHA_{ijxt} - \sum_{i} NonSpinReceiveHA_{ijxt}$$

(d) Replacement Reserve. When the ISO purchases Replacement Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payments for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Replacement Reserve capacity over the Trading Interval will be the total quantity of Replacement Reserve capacity provided times the ~~z~~Zonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Replacement Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$ReplPayHA_{ijxt} = ReplQIHA_{ijxt} * PReplHA_{xt}$$

When a Scheduling Coordinator buys back in the Hour-Ahead Market Replacement Reserve capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Replacement Reserve capacity bought back times the ~~z~~Zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Replacement Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$ReplReceiveHA_{ijxt} = ReplQDHA_{ijxt} * PReplHA_{xt}$$

The total Replacement Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Replacement Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$ReplPayTotalHA_{jxt} = \sum_{i} ReplPayHA_{ijxt} - \sum_{i} ReplReceiveHA_{ijxt}$$

C 2.2 ISO allocation of charges to Scheduling Coordinators

C 2.2.1 Day-Ahead Market

(a) *Regulation*. The ISO will charge the ~~z~~Zonal cost of providing Regulation capacity that is not self-provided by Scheduling Coordinators, in the Day-Ahead Market, through the application of a charge to each Scheduling Coordinator for each Trading Interval. This charge will be computed by multiplying the Regulation user rate for the Trading Interval by the Scheduling Coordinator's Regulation obligation, for which it has not self-provided, for the same period.

The ~~z~~Zonal Regulation user rate for the Day-Ahead Market is calculated by dividing the total cost to ISO of purchasing Regulation Capacity within the Zone, for the Trading Interval, by the total ISO Regulation MW purchases for the Trading Interval within the Zone. Regulation Up and Regulation Down payments shall be calculated separately.

The Day-Ahead Regulation Up user rate in Zone x for Trading Interval t is calculated as follows:

$$AGCUpRateDA_{xt} = \frac{\sum_{j} AGCUpPayTotalDA_{jxt}}{AGCUpPurchDA_{xt}}$$

where,

$AGCUpPayTotalDA_{jxt}$ = Total Regulation Up payments for the Settlement Period t in the Day-Ahead ~~m~~Market for the Zone x.

The Day-Ahead Regulation Down user rate in Zone x for Trading Interval t is calculated as follows:

$$AGCDownRateDAxt = \frac{\sum_{j} AGCDownPayTotalDAjxt}{AGCDownPurchDAxt}$$

where,

$AGCDownPayTotalDA_{jxt}$ = Total Regulation Down payments for the Settlement Period t in the Day-Ahead Market for the Zone x.

The Regulation capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$AGCUpChgDA_{jxt} = AGCUpOblig_{jxt} * AGCUpRateDA_{xt}$$

$$AGCDownChgDA_{jxt} = AGCDownOblig_{jxt} * AGCDownRateDA_{xt}$$

(b) Spinning Reserve. The ISO will charge the zZonal cost of providing Spinning Reserve capacity that is not self-provided by Scheduling Coordinators, in the Day-Ahead Market, through the application of a charge to each Scheduling Coordinator for each Trading Interval. This charge will be computed by multiplying the Spinning Reserve capacity user rate for the Trading Interval by the Scheduling Coordinator's Spinning Reserve obligation, for which it has not self-provided, for the same period. The zZonal Spinning Reserve capacity user rate for the Day-Ahead Market is calculated by dividing the total cost to ISO of purchasing Spinning Reserve capacity within the Zone, for the Trading Interval, by the total ISO Spinning Reserve MW purchases for the Trading Interval within the Zone. The Day-Ahead Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$SpinRateDA_{xt} = \frac{\sum_{j} SpinPayTotalDA_{jxt}}{SpinPurchDA_{xt}}$$

The Spinning Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$SpinChgDA_{jxt} = SpinOblig_{jxt} * SpinRateDA_{xt}$$

(c) Non-Spinning Reserve. The ISO will charge the zZonal cost of providing Non-Spinning Reserve capacity that is not self-provided by Scheduling Coordinators, in the Day-Ahead Market, through the application of a charge to each Scheduling Coordinator for each Trading Interval. This charge will be computed by multiplying the Non-Spinning Reserve capacity user rate for the Trading Interval by the Scheduling Coordinator's Non-Spinning Reserve obligation, for which it has not self-provided, for the same period.

The zZonal Non-Spinning Reserve capacity user rate for the Day-Ahead Market is calculated by dividing the total cost to ISO of purchasing Non-Spinning Reserve capacity within the Zone, for the Trading Interval, by the total ISO Non-Spinning Reserve MW purchases for the Trading Interval within the Zone. The

Day-Ahead Non-Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$NonSpinRateDA_{xt} = \frac{\sum_{j} NonSpinPayTotalDA_{jxt}}{NonSpinPurchDA_{xt}}$$

The Non-Spinning Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$NonSpinChgDA_{jxt} = NonSpinOblig_{jxt} * NonSpinRateDA_{xt}$$

C 2.2.2 Hour-Ahead Market

(a) Regulation. The ISO will charge the ~~z~~Zonal net cost of providing Regulation capacity that is not self-provided by Scheduling Coordinators, in the Hour-Ahead Market through the application of a charge to each Scheduling Coordinator for the Trading Interval concerned. This charge will be computed by multiplying the Regulation user rate for the Trading Interval by the Scheduling Coordinator's Regulation obligation, for which it has not self-provided, for the same period.

The ~~z~~Zonal Regulation capacity user rate for the Hour-Ahead Market is calculated by dividing the total cost to the ISO of purchasing Regulation capacity within the Zone less any amounts payable to the ISO by Scheduling Coordinators for Regulation bought back from the ISO in the Hour-Ahead Market on behalf of resources located in the Zone, for the Trading Interval, by the total ISO Regulation capacity MW purchases for the Trading Interval within the Zone. Regulation Up and Down payments shall be calculated separately. The Hour-Ahead Regulation Up capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$AGCUpRateHA_{xt} = \frac{\sum_{j} AGCUpPayTotalHA_{jxt}}{AGCUpPurchHA_{xt}}$$

where,

$AGCUpPayTotalHa_{jxt}$= Totlal Regulation Up payments for the Settlement Period t in the Hour-Ahead Market for Zone x.

The Hour-Ahead Regulation Down capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$AGCDownRateHAxt \frac{\sum_{j} AGCDownPayTotalHAjxt}{AGCDownPurchHAxt}$$

where,

$AGCDownPayTotalHA_{xt}$ = Total Regulation Down payments for the Settlement Period t in the Hour-Ahead Market for Zone x.

The Regulation capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$AGCUpChgHA_{jxt} = (AGCUpOblig_{jxt} * AGCUpRateHA_{xt})$$

$$AGCDownChgHA_{jxt} = (AGCDownOblig_{jxt} * AGCDownRateHA_{xt})$$

(b) Spinning Reserve. The ISO will charge the ~~z~~Zonal net cost of providing Spinning Reserve capacity that is not self-provided by Scheduling Coordinators, in the Hour-Ahead Market, through the application of a charge to each Scheduling Coordinator for the Trading Interval. This charge will be computed by multiplying the Spinning Reserve capacity user rate for the Trading Interval by the Scheduling Coordinator's Spinning Reserve obligation, for which it has not self-provided, for the same period. The ~~z~~Zonal Spinning Reserve capacity user rate for the Hour-Ahead Market is calculated by dividing the total cost to ISO of purchasing Spinning Reserve capacity within the Zone less any amounts payable to the ISO by Scheduling Coordinators for Spinning Reserve bought back from the ISO in the Hour-Ahead Market on behalf of resources located in the Zone, for the Trading Interval, by the total ISO Spinning Reserve MW purchases for the Trading Interval within the Zone. The Hour-Ahead Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$SpinRateHA_{xt} = \frac{\sum_{j} SpinPayTotalHA_{jxt}}{SpinPurchHA_{xt}}$$

The Spinning Reserve capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$SpinChgHA_{jxt} = (SpinOblig_{jxt} * SpinRateHA_{xt})$$

(c) Non-Spinning Reserve. The ISO will charge the ~~z~~Zonal net cost of providing Non-Spinning Reserve capacity that is not self-provided by Scheduling Coordinators, in the Hour-Ahead Market, through the application of a charge to each Scheduling Coordinator for the Trading Interval. This charge will be computed by multiplying the Non-Spinning Reserve capacity user rate for the concerned Trading Interval by the Scheduling Coordinator's Non-Spinning Reserve obligation, for which it has not self-provided, for the same period. The ~~z~~Zonal Non-Spinning Reserve capacity user rate for the Hour-Ahead Market is calculated by dividing the total cost to ISO of purchasing Non-Spinning Reserve capacity within the Zone less any amounts

payable to the ISO by Scheduling Coordinators for Non-Spinning Reserve bought back from the ISO in the Hour-Ahead Market on behalf of resources in the Zone, for the Trading Interval, by the total ISO Non-Spinning Reserve MW purchases for the Trading Interval within the Zone. The Hour-Ahead Non-Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$NonSpinRateHA_{xt} = \frac{\sum_{j} NonSpinPayTotalHA_{jxt}}{NonSpinObligTotal_{xt}}$$

The Non-Spinning Reserve capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$NonSpinChgHA_{jxt} = (NonSpinOblig_{jxt} * NonSpinRateHA_{xt})$

C 2.2.3 Replacement Reserve

The user rate per unit of Replacement Reserve obligation for each Settlement Period t for each Zone x shall be as follows:

$$ReplRate_{xt} = \frac{(PRepResDA_{xt} * OrigReplReqDA_{xt}) + (PRepResHA_{xt} * OrigReplReqHA_{xt})}{OrigReplReqDA_{xt} + OrigReplReqHA_{xt}}$$

where:

$OrigReplReqDA_{xt}$ = Replacement Reserve requirement net of self-provision in the Day-Ahead Market before consideration of any substitutions pursuant to Section 2.5.3.6.

$OrigReplReqHA_{xt}$ = Incremental change in the Replacement Reserve requirement net of self-provision between the Day-Ahead Market and the Hour-Ahead Market before consideration of any substitutions pursuant to Section 2.5.3.

$PRepResDA_{xt}$ is the Market Clearing Price for Replacement Reserve in the Day-Ahead Market for Zone *x* in Settlement Period *t*.

$PRepResHA_{xt}$ is the Market Clearing Price for Replacement Reserve in the Hour-Ahead Market for Zone *x* in Settlement Period *t*.

For each Settlement Period t, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone x:

$ReplRate_{xt} * ReplOblig_{jxt}$

where

$$ReplOblig_{jxt} = DevReplOblig_{jxt} + RemRepl_{jxt} - SelfProv_{jxt} + NetInterSCTrades_{jxt}$$

$DevReplOblig_{jxt}$ is the Scheduling Coordinator's obligation for deviation Replacement Reserve in Zone x in the Settlement Period t and $RemRepl_{jxt}$ is the Scheduling Coordinator's obligation for remaining Replacement Reserve in Zone x for Settlement Period t.

$SelfProv_{jxt}$ is Scheduling Coordinator's Replacement Reserve self-provision in Zone x for Settlement Period t.

$NetInterSCTrades_{jxt}$ is the sale of Replacement Reserve less the purchase of Replacement Reserve through Inter-Scheduling Coordinator Trades by Scheduling Coordinator j in Zone x for Settlement Period t.

Deviation Replacement Reserve for Scheduling Coordinator i in Zone x for Settlement Period t is calculated as follows:

If $ReplObligTotal_{xt} > TotalDeviations_{xt}$ then:

$$DevReplOblig_{xjt} = \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]$$

If $ReplObligTotal_{xt} < TotalDeviations_{xt}$ then:

$$DevReplOblig_{xjt} = \frac{ReplObligTotal_{xt}}{TotalDeviations_{xt}} * \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]$$

where,

$$TotalDeviations_{xt} = \sum_j \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]$$

$GenDev_{ijxt}$ = The deviation between scheduled and actual Energy generation for Generator i represented by Scheduling Coordinator I in Zone x during Settlement Period t as referenced in SABP Appendix D.

$LoadDev_{ijxt}$ = The deviation between scheduled and actual Load consumption for resource I represented by Scheduling Coordinator iin Zone x during Settlement Period t as referenced in SABP Appendix D.

$DevReplOblig_{xt}$ is total deviation Replacement Reserve in Zone x for Settlement Period t.

$ReplObligTotal_{xt}$ is total Replacement Reserve Obligation in Zone x for Settlement Period t.

Remaining Replacement Reserve for Scheduling Coordinator j in Zone x for Settlement Period t is calculated as follows:

$$RemRepl_{xjt} = \frac{MeteredDemand_{jxt}}{TotalMeteredDemand_{xt}} * TotalRemRepl_{xt}$$

where:

$MeteredDemand_{jxt}$ is the Scheduling Coordinator's total metered Demand excluding exports in Zone x for Settlement Period t.

$TotalMeteredDemand_{xt}$ is total metered Demand excluding exports in Zone x for Settlement Period t.

$TotalRemRepl_{xt} = Max[0, ReplObligTotal_{xt} - DevReplOblig_{xt}]$

C 2.2.4 Rational Buyer Adjustments

(a) If, in any Settlement Period, no quantity of Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve is purchased in the Day-Ahead Market or the Hour-Ahead Market due to the operation of Section 2.5.3.6 of the ISO Tariff, then in lieu of the user rate determined in accordance with Section C 2.2.1, C 2.2.2, or C 2.2.3, as applicable, the user rate for the affected Ancillary Service for that Settlement Period shall be determined as follows:

(i) If the affected market is a Day-Ahead Market, the user rate for the affected Ancillary Service shall be set at the lowest capacity reservation price for an unaccepted qualified capacity bid in a Day-Ahead Market for that Ancillary Service or for another Ancillary Service that meets the requirements for the affected Ancillary Service. If there are no such unaccepted bids, the user rate for the affected Ancillary Service shall be the lowest Market Clearing Price for the same Settlement Period established in the Day-Ahead Market for another Ancillary Service that meets the requirements for the affected Ancillary Service.

(ii) If the affected market is an Hour-Ahead Market, the user rate for the affected Ancillary Service shall be set at the lowest capacity reservation price for an unaccepted qualified capacity bid in the Hour-Ahead Market for the same Settlement Period for that Ancillary Service or for another Ancillary Service that meets the requirements for the affected Ancillary Service. If there are no such unaccepted bids, the user rate for the affected Ancillary Service shall be the user rate for the same Ancillary Service in the Day-Ahead Market in the same Settlement Period.

(b) With respect to each Settlement Period, in addition to the user rates determined in accordance with Sections C 2.2.1 through C 2.2.3, or Section C 2.2.4(a), as applicable, each Scheduling Coordinator shall be charged an additional amount equal to its proportionate share, based on total purchases by Scheduling Coordinators of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve of the amount, if any, by which (i) the total payments to Scheduling Coordinators pursuant to Section C 2.1 for the Day-Ahead Market and Hour-Ahead Market and all Zones, exceed (ii) the total amounts charged to Scheduling Coordinators pursuant to Sections C 2.2.1 through C 2.2.3, for the Day-Ahead Market and Hour-

Ahead Market and all Zones. If total amounts charged to Scheduling Coordinators exceed the total payments to Scheduling Coordinators, each Scheduling Coordinator will be refunded its proportionate share, based on total purchases by Scheduling Coordinators of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve.

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C 3.20A **$REPA_{ijxt}$ - $**

The Regulation Energy Payment Adjustment payable for real-time incremental or decremental Energy provided from Regulation resource i of Scheduling Coordinator j in Zone x in Trading Interval t.

***

C 3.26 **$SpinPayTotalHA_{jxt}$ - $**

The total payment to Scheduling Coordinator j for incremental (additional to Day-Ahead) Spinning Reserve capacity in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead ~~m~~Market in Zone x for Trading Interval t.

***

C 3.39.1 **$PNonSpinHA_{xt}$ - $/MW**

The Hour-Ahead ~~z~~Zonal Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Non-Spinning Reserve capacity for Trading Interval t in Zone x. On Buyback condition, MCP applies.

***

C 3.40 **$NonSpinPayTotalHA_{jxt}$ - $**

The total payment to Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Non-Spinning Reserve capacity in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of

payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Non-Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Mmarket in Zone x for Trading Interval t.

***

C 3.59 **$ReplChgHA_{jxt}$ - $**

The incremental (additional to Day-Ahead) Replacement Reserve capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in zZone x for Trading Interval t.

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C 3.61 **$ReplPayTotal_{jxt}$ - $**

The total payment to Scheduling Coordinator j for providing Replacement Reserve capacity in the Day-Ahead and Hour-Ahead Markets in zZone x for Trading Interval t.

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SETTLEMENT AND BILLING PROTOCOL

APPENDIX D

IMBALANCE ENERGY CHARGE COMPUTATION

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D 2.1.1 Uninstructed Imbalance Energy Charges on Scheduling Coordinators

Uninstructed Imbalance Energy attributable to each Load Take-Out Point, Generating Unit, System Unit, or System Resource for which a Scheduling Coordinator has a Final Hour-Ahead Schedule or Metered Quantity, for each Settlement Interval shall be deemed to be sold or purchased, as the case may be, by the ISO and charges or payments for Uninstructed Imbalance Energy shall be settled by debiting or crediting, as the case may be, the Scheduling Coordinator with an amount for each Settlement Interval.

Uninstructed Imbalance Energy within a Settlement Interval shall be settled in two tiers that are defined in relation to the expected Energy associated with the Final Hour-Ahead Schedule, if any, and the Dispatch Instruction as follows:

1) Deviations from the expected Energy associated with a Dispatch Instruction resulting in: 1) under delivery of Instructed Imbalance Energy that is also equal to or greater than the Final Hour-Ahead Schedule, or 2) over delivery of Instructed Imbalance Energy that is also less than or equal to the Final Hour-Ahead Schedule constitutes tier 1 Uninstructed Imbalance Energy that shall be settled at a Resource-Specific Settlement Interval Ex Post Price as described in Appendix D 2.4.

2) Deviations from the expected Energy associated with a Dispatch Instruction resulting in: 1) over delivery of Instructed Imbalance Energy that is also greater than the Final Hour-Ahead Schedule, or 2) under delivery of Instructed Imbalance Energy that is also less than the Final Hour-Ahead Schedule constitutes tier 2 Uninstructed Imbalance Energy and shall be settled at the Zonal Settlement Interval Ex Post Price as described in Appendix D 2.5.

Imbalance Energy is calculated as follows:

Generator Calculation for ISO Metered Entities:

$$IE_{i,h,o} = ME_{i,h,o} - SE_{i,h,o}$$

Load Calculation:

$$IE_{i,h,o} = SE_{i,h,o} - ME_{i,h,o}$$

System Resource Calculation:

$$IE_{i,h,o} = \sum_{1}^{k}\sum_{1}^{v} REAL_TIME_FLOW_{i,h,o,k,v} - SE_{i,h,o}$$

where,

$$SE_{i,h,o} = \frac{HAfin_{i,h}}{6}$$

$ME_{i,h,o}$ actual ~~m~~Meter ~~d~~Data for each resource *i* of each Settlement Interval *o* for each hour *h*.

Uninstructed Imbalance Energy is calculated as follows:

$$UIE_{i,h,o} = E_{i,h,o} - IIE_REG_{i,h,o}$$

where:

$$E_{i,h,o} = IE_{i,h,o} - \sum_{1}^{k} IIE_LOSS_{i,h,o,k} - \sum_{1}^{k} IIE_ML_{i,h,o,k} - \sum_{1}^{k}\sum_{1}^{m} IIE_PREDISPATCH_{i,h,o,k,m} - \sum_{1}^{k} RE_STANDARD_{i,h,o,k} - \sum_{1}^{k} RED_{i,h,o,k} - \sum_{1}^{k}\sum_{1}^{m} IIE_ECON_{i,h,o,k,m} - \sum_{1}^{k}\sum_{1}^{L} OOS_P_{i,h,o,k,L} - \sum_{1}^{k}\sum_{1}^{L} OOS_N_{i,h,o,k,L} - \sum_{1}^{k}\sum_{1}^{m} RIE_{i,h,o,k,m} - \sum_{1}^{k} IIE_RERATE_{i,h,o,k}$$

$IIE_REG_{i,h,o}$ is the Regulating Energy for resource *i* during Settlement Interval *o* in hour *h*

$$UIE_1_{i,h,o} = \begin{cases} \min\left(UIE_{i,h,o}, -\min\left(0, \sum_{1}^{k}\sum_{1}^{m} IIE_ECON_{i,h,o,k,m} + \sum_{1}^{k}\sum_{1}^{m} IIE_PREDISPATCH_{i,h,o,k,m} \right.\right. \\ \qquad + \sum_{1}^{k}\sum_{1}^{L} OOS_P_{i,h,o,k,L} + \sum_{1}^{k}\sum_{1}^{L} OOS_N_{i,h,o,k,L} + \sum_{1}^{k} RED_{i,h,o,k} \\ \qquad \left.\left. + \sum_{1}^{k} IIE_LOSS_{i,h,o,k} + \sum_{1}^{k}\sum_{1}^{m} RIE_{i,h,o,k,m} + \sum_{1}^{k} IIE_ML_{i,h,o,k} + \sum_{1}^{k} RERATE_{i,h,o,k} \right) \right) \\ \max\left(UIE_{i,h,o}, -\max\left(0, \sum_{1}^{k}\sum_{1}^{m} IIE_ECON_{i,h,o,k,m} + \sum_{1}^{k}\sum_{1}^{m} IIE_PREDISPATCH_{i,h,o,k,m} \right.\right. \\ \qquad + \sum_{1}^{k}\sum_{1}^{L} OOS_P_{i,h,o,k,L} + \sum_{1}^{k}\sum_{1}^{L} OOS_N_{i,h,o,k,L+} + \sum_{1}^{k} RED_{i,h,o,k} \\ \qquad \left.\left. + \sum_{1}^{k} IIE_LOSS_{i,h,o,k} + \sum_{1}^{k}\sum_{1}^{m} RIE_{i,h,o,k,m} + \sum_{1}^{k} IIE_ML_{i,h,o,k} + \sum_{1}^{k} RERATE_{i,h,o,k} \right) \right) \end{cases}$$

$$UIE_2_{i,h,o} = UIE_{i,h,o} - UIE_1_{i,h,o}$$

$$UIEC_{i,h,o} = \left(-1 * UIE_1_{i,h,o} * STLMT_PRICE_{i,h,o}\right) + \left(-1 * UIE_2_{i,h,o} * ZONAL_EX_POST_PRICE_{j,h,o}\right)$$

D 2.1.2 Instructed Imbalance Energy Charges on Scheduling Coordinators

Standard Ramping Energy is Energy associated with a Standard Ramp and shall be deemed delivered and settled at a price of zero dollars per MWh.

Ramping Energy Deviation is Energy produced or consumed due to hourly schedule changes in excess of Standard Ramping Energy and shall be paid or charged, as the case may be, at a Resource-Specific Settlement Interval Ex Post Price calculated using the applicable Dispatch Interval Ex Post Prices as described in this Appendix D 2.4. For Scheduling Coordinators scheduling a MSS that has elected to follow its Load, this Ramping Energy Deviation will account for the units following Load.

Ramping Energy Deviation shall be settled as an explicit component of Instructed Imbalance Energy for each resource *i* in Dispatch Interval *k* of Settlement Interval *o* for hour *h*, and calculated as follows:

$$REDC_{i,h,o} = \left(\sum_{1}^{k} RED_{i,h,o,k} \right) * STLMT_PRICE_{i,h,o}$$

The amount of Instructed Imbalance Energy that will be deemed delivered in each Dispatch Interval will be based on Dispatch Instructions, as provided for in Section 2.5.22.6, and Final Hour-Ahead

Schedules. The amount of Instructed Imbalance Energy to be settled in a Settlement Interval will be equal to the sum of all Instructed Imbalance Energy for all Dispatch Intervals within the relevant Settlement Interval. Instructed Imbalance Energy for each Settlement Interval shall be settled at the relevant Resource Specific Settlement Interval Ex Post Price. Generating Units, Participating Loads, and System Units may be eligible to recover their Energy Bid costs in accordance with Section 11.2.4.1.1.1. Instructed Imbalance Energy from System Resources shall be settled in accordance with Section 11.2.4.1.1.2.

The Instructed Imbalance Energy amount for each resource *i* in Settlement Interval *o* for hour *h* shall be determined as follows:

$$IIEC_{i,h,o} = \left(\sum_{1}^{k} \sum_{1}^{m} IIE_ECON_{i,h,o,k,m} + \sum_{1}^{k} \sum_{1}^{m} IIE_PREDISPATCH_{i,h,o,k,m} + \sum_{1}^{k} \sum_{1}^{m} RIE_{i,h,o,k,m} + \sum_{1}^{k} IIE_RERATE_{i,h,o,k} + \sum_{1}^{k} IIE_ML_{i,h,o,k} \right)$$

$$* STLMT_PRICE_{i,h,o} * (-1) + IIEC_OOS_{i,h,o} + REDC_{i,h,o} + IIEC_REG_{i,h,o}$$

Uninstructed Imbalance Energy is Imbalance Energy due to non-compliance with a Dispatch Instruction and shall be settled as provided for in SABP Appendix D Section 2.1.1.

D 2.2 Unaccounted for Energy Charge

The Unaccounted for Energy Charge on Scheduling Coordinator *g* in Settlement Interval *o* of Settlement Period *h* for each relevant Zone *j* is calculated in the following manner:

The UFE for each utility Service Area *s*, for which separate UFE calculation is performed, is calculated as follows,

$$UFE_{UDC,s,h,o} = \sum_{q \in UDC_s} I_{a,q,j,h,o} - \sum_{q \in UDC_s} E_{a,q,j,h,o} + \sum_{i \in UDC_s} G_{a,i,j,h,o} - \sum_{i \in UDC_s} L_{a,i,j,h,o} - TL_{s,h,o}$$

The Transmission Loss $TL_{s,h,o}$ in Settlement Interval *o* of Settlement Period *h* for utility Service Area *s* is calculated as follows:

$$TL_{s,h,o} = \left(\sum_{i} \left[G_{a,i,j,h,o} * (1 - GMM_{a,i,h}) \right] + \sum_{q} \left[I_{a,q,j,h,o} * (1 - GMM_{a,q,h}) \right] \right) * \frac{PFL_{s,h}}{\sum_{s} PFL_{s,h}}$$

Where $PFL_{s,h}$ are the tTransmission lLosses for utility Service Area *s* as calculated by a power flow solution for Settlement Period *h*, consistent with the calculation of final forecasted Generation Meter Multipliers.

Each metered demand point *z* in utility Service Area *s*, either ISO grid connected or connected through UDC *s*, is allocated a portion of the UFE as follows:

$$UFE_{i,j,h,o} = UFE_{UDC,s,h,o} * \frac{L_{i,j,h,o}}{\sum_{i \in UDC_s} L_{i,j,h,o}}$$

The UFE charge for Scheduling Coordinator *g* for Settlement Interval *o* of Settlement Period *h* in Zone *j* is calculated as a charge or payment using the applicable Zonal Settlement Interval Ex Post Price as follows:

$$UFEC_{g,j,h,o} = \left(\sum_{i \in SCg} UFE_{i,j,h,o,} \right) * ZONAL_EX_POST_PRICE_{j,h,o}$$

D 2.3 Hourly Ex Post Price

The Hourly Ex Post Price is the Energy-weighted average of the Dispatch Interval Ex Post ~~p~~Prices in each Zone *j* during each Settlement Period using the absolute value of Instructed Imbalance Energy procured from all Participating Generators, Participating Load, System Units, and System Resources in each applicable Dispatch Interval. The Hourly Ex Post Price may vary between Zones if Congestion is present.

$$HP_{j,h} = \frac{\sum_{1}^{p} \sum_{1}^{i} \left| IIE_TOTAL_{j,i,h,p} \right| * EX_POST_PRICE_{j,h,o,p}}{\sum_{1}^{p} \sum_{1}^{i} \left| IIE_TOTAL_{j,i,h,p} \right|}$$

where,

p is the Dispatch Interval index for hour *h*.

**

D 2.6 Calculation of Unrecovered Cost Payment for Generators

As set forth in 11.2.4.1.1.1, Generator resources will be eligible to recover their bid costs (less than or equal to the Maximum Bid Level) for extra-marginal Energy dispatched above Pmin, if such costs are not recovered from the net of expected revenues earned through participation in the ISO's ~~r~~Real-~~t~~Time ~~m~~Market during the Trade Day (24-hour period). The expected market revenue deficits will only be included in the calculation for Settlement Intervals the resource operates within its relevant Tolerance Band. Additionally, resources will not recover the amount of these bid recovery costs allocated to each Settlement Interval in those Settlement Intervals in which the resource is operating outside of its relevant Tolerance Band.

The Unrecovered Cost Payment for each resource i shall be determined for the Trade Day *d* then evenly divided over n-Settlement Intervals as follows:

$COST_RECOVERY_{i,d}$ =

$$min(0, \sum_{1}^{h} \sum_{1}^{o} (PERF_STAT_{i,h,o} * MR_DEFICIT_{i,h,o} + MR_SURPLUS_{i,h,o})$$

where,

$MR_DEFICIT_{i,h,o}$ = Market Revenue deficit for resource i in hour h for Settlement interval o based on the difference between the expected revenues earned in the Settlement Interval and and/or its bid cost;$MR_SURPLUS_{i,h,o}$= Market Revenue surplus for resource i in hour h for Settlement interval o based on the difference between the expected revenues earned in the Settlement Interval and/or its bid cost.

Resource i shall receive a share of its total cost recovery in each Settlement Interval o that is included in the $COST_RECOVERY_{i,d}$ calculation above if it operates within its relevant Tolerance Band during the relevant Settlement Interval o.

$COST_RECOVERY_{i,h,o} = PERF_STAT_{i,h,o} * COST_RECOVERY_{i,d} / n$

where,

n is the number of Settlement Intervals o that are included in the $COST_RECOVERY_{i,d}$ calculation for resource i in Trade Day d.

Calculation of Market Revenue Surplus or Deficit

The market revenue surplus or deficit for each resource i will be computed for each Settlement Interval o based on the difference between the revenues earned in the Settlement Interval at the relevant 10-minute Ex Post price and the resource's bid cost (less than or equal to the Maximum Bid Level) as follows:

$$MR_DIFF_{i,h,o} = \left(\sum_{1}^{k} \sum_{1}^{m} IIE_ECON_{i,h,o,k,m} + \sum_{1}^{k} \sum_{1}^{m} RIE_{i,h,o,k,m} \right) * STLMT_PRICE_{i,h,o} - BID_COST_{i,h,o} - BID_COST_RIE_{i,h,o}$$

for all incremental energy bid segments m with $IIE_PRICE_{i,h,o,k,m}$ and $RIE_PRICE_{i,h,o,k,m}$ less than or equal to the Maximum Bid Level and all decremental energy bid segments m with $IIE_PRICE_{i,h,o,k,m}$ and $RIE_PRICE_{i,h,o,k,m}$ greater than or equal to the Bid Floor.

$MR_DEFICIT_{i,h,o}$ = $min(0, MR_DIFF_{i,h,o})$

$MR_SURPLUS_{i,h,o}$ = $\max(0, MR_DIFF_{i,h,o})$

where,

$$BID_COST_{i,h,o} = \left(\sum_{1}^{k} \sum_{1}^{m} IIE_ECON_{i,h,o,k,m} * IIE_PRICE_{i,h,o,k,m} \right)$$

$$BID_COST_RIE_{i,h,o} = \sum_{1}^{k} \sum_{1}^{m} RIE_{i,h,o,k,m} * RIE_PRICE_{i,h,o,k,m}$$

D 2.6.1 Tolerance Band and Performance Check

The ISO shall determine the Tolerance Band for each Settlement Interval *o* for PGA resources based on the data from the Master File as follows:

$$TOLERANCE_BAND_{i,h,o} = \pm \max\left(FIX_LIM\ , TOL_PERCENT\ * P\max_i\right) / 6$$

where,
FIX_LIM is a fixed MW limit and is initially equal to 5 MW.
TOL_PERCENT is a fixed percentage and is initially equal to 3%.*Pmax*$_i$ is the maximum operating capacity in MW of resource *i* specified in the Master File.

The ISO shall determine the Tolerance Band for each Settlement Interval *o* for PLA resources as follows:

$$TOLERANCE_BAND_{i,h,o} = \pm\ max\left(FIX_LIM,\ TOL_PERCENT * HAfin_{i,h}\right) / 6$$

where *HAfin*$_{i,h}$ *is the* Final Hour Ahead Energy Schedule.

Resources must operate within their relevant Tolerance Band in order to receive any above-Ex Post ~~p~~Price payments. The ISO shall determine the performance status of the resource for each Settlement Interval o.

A resource shall have met its performance requirement if its $UIE_{i,h,o}$ is within its relevant Tolerance Band. A resource meeting its performance requirement in Settlement Interval o will have a $PERF_STAT_{i,h,o} = 1$. A resource that has not met its performance requirement in Settlement Interval *o* will have a $PERF_STAT_{i,h,o} = 0$.

Must offer resources that produce a quantity of Energy above Minimum Load due to an ISO Dispatch Instruction are not subject to the Tolerance Band requirement for purposes of receiving either Minimum Load Cost Compensation, as defined in section 5.11.6.1.1, or Bid Cost Recovery, as set forth in section 11.2.4.1.1.1. Accordingly, the $PERF_STAT_{i,h,o}$ for eligible must offer resources, as defined in section 5.11.6.1.1, shall be set to 1, irrespective of deviations outside of the Tolerance Band.

System Resources do not have a Tolerance Band. Non--Participating Load Agreement (PLA) load resources are not subject to the performance requirement.

D 2.6.2 Unrecovered Costs Neutrality Allocation

For each Settlement Interval *o*, the total Unrecovered Costs for Trade Day *d* shall be allocated pro-rata to each Scheduling Coordinator *g* based on its Metered Demand, calculated as follows:

$URC_ALLOC_{g,h,o} = M_{g,h,o} * Per\ Unit\ Price$

where,

$M_{g,h,o}$ = the Metered Demand in the ISO ~~c~~Control a<u>A</u>rea for Scheduling Coordinator *g* in Settlement Interval *o* for hour *h*;

$$Per\ Unit\ Price = \frac{-1 * \sum_{1}^{i} COST_RECOVERY_{i,h,o}}{\sum_{1}^{g} M_{g,h,o}}$$

D 2.6.3 Calculation of Unrecovered Cost Payment for System Resources

As set forward in Section 11.2.4.1.1.2, System Resources that are dispatched and deliver hourly-predispatched Instructed Imbalance Energy will be paid the higher of the simple average of the twelve Dispatch Interval Ex Post ~~p~~<u>P</u>rices for the hour or their Energy bid costs for the quantity of Energy delivered in each hour. The determination of the hourly uplift payment shall be determined as follows: (1) Market deficits or surpluses are calculated as the difference between the resource-specific price and the resource's (hourly) bid cost; (2) An hourly uplift payment will be determined for any amount less than zero; (3) This hourly amount will then be divided evenly by the relevant number of *n*-Settlement Intervals and paid this portion for each Settlement Interval of the hour.

The hourly-predispatched uplift payment is calculated as follows:

$$PREDISPATCH_UPLIFT_{i,h} =$$

$$min\left(0, \sum_{1}^{o}\left(\left(\sum_{k=1}^{2}\sum_{1}^{m} IIE_PREDISPATCH_{i,h,o,k,m}\right) * STMLT_PRICE_{i,h,o} - \left(\sum_{k=1}^{2}\sum_{1}^{m} IIE_PREDISPATCH_{i,h,o,k,m} * IIE_PRICE_{i,h,o,k,m}\right)\right)\right)$$

$$PREDISPATCH_PMT_{i,h,o} = PREDISPATCH_UPLIFT_{i,h} / n$$

where,
n is the relevant number of Settlement Intervals *o* in the relevant hour *h* for resource *i.*

<u>for the portion of incremental energy bid segments with $IIE_PRICE_{i,h,o,k,m}$ less than or equal to the Maximum Bid Level and all decremental energy bid segments with $IIE_PRICE_{i,h,o,k,m}$ greater than or equal to the Bid Floor.</u>

***

D 2.8 Uninstructed Deviation Penalty Charges

For negative Uninstructed Deviation Penalty billable quantities where $UDP_BQ_{h,o} < 0$ and $ZONAL_EX_POST_PRICE_{j,h,o} > 0$,
$UDP_NEG_Amt_i\ AMT_{i\,h,o}$ =
$-1 * UDP_BQ_{i,h,o} * ZONAL_EX_POST_PRICE_{j,h,o} * .5$

For positive UDP billable quantities where $UDP_BQ_{i,h,o} > 0$ and $ZONAL_EX_POST_PRICE_{j,h,o} > 0$, then
$UDP_POS_AMT_{i,h,o} = UDP_BQ_{i,o,h} * ZONAL_EX_POST_PRICE_{j,h,o}$

where,

$UDP_BQ_{i,o,h}$ is the Uninstructed Deviation Penalty (UDP) billable quantity in MWh for a resource, or aggregated resource, denoted by i for Settlement Interval *o* of hour *h.*

$UDP_POS_AMT_{i,o,h}$ or $UDP_NEG_AMT_{i,o,h}$ are the penalty amounts in Dollars for either an aggregated or individual resource *i* for Settlement Interval *o* of hour *h.*

The ISO will not calculate UDP settlement amounts for Settlement Intervals when the corresponding Zonal Settlement Interval Ex Post ~~p~~Price is negative or zero.

For an MSS that has elected to follow its own Load, the Scheduling Coordinator for the MSS Operator will be assessed the Uninstructed Deviation Penalty charges based on the Deviation Band and Deviation Price in Section 23.12.2 of the ISO Tariff.

***

D 3.26 $UFEC_{jxt}$ – $

The Unaccounted for Energy Charge for Scheduling Coordinator j in Zone x in Settlement Period t. It is the cost for the Energy difference between the net Energy delivered into each ~~UDC~~Utility Service Area, adjusted for ~~UDC~~Utility Service Area Transmission Losses (calculated in accordance with ISO Tariff Section 7.4.2~~3~~), and the total metered Demand within that ~~UDC~~Utility Service Area adjusted for distribution losses using Distribution System loss factors approved by the Local Regulatory Authority.

This Energy difference (UFE) is attributed to meter measurement errors, power flow modeling errors, energy theft, statistical Load profile errors, and distribution loss deviations.

***

D 3.49 **$EX_POST_PRICE_{j,h,o,k}$ – $/MWh**

The Ex-~~ }~~Post ~~p~~Price in Dispatch Interval *k* of Settlement Interval *o* in Settlement Period *h* in ~~z~~Zone *j*.

D 3.50 **$HRLY_EX_POST_PRICE_{j,h}$ – $/MWh**

The energy-weighted Ex Post ~~p~~Price for Settlement Period *h* in ~~z~~Zone *j*.

D 3.51 **$STLMT_PRICE_{i,h,o}$ – $/MWh**

The 10-minute Settlement price (~~r~~Resource-~~s~~Specific Settlement Interval Ex Post ~~p~~Price) for resource *i* in the Settlement Interval *o* for the Settlement Period *h.*

D 3.52 **$SE_{i,h,o}$ – MWh**

The Scheduled Energy from resource *i* during Settlement ~~i~~Interval *o* of Settlement Period *h.*

***

D 3.56 **$IIE_PREDISPATCH_{i,h,o,k,m}$ – MWh**

The Settlement Period~~ly~~ pre-dispatched Energy for resource *i* during Dispatch Interval *k* of Settlement Interval *o* of Settlement Period *h* for bid segment *m* (MWh).

***

D 3.58 **$RIE_PRICE_{i,h,o,k,m}$ – $/MWh**

The reference bid price for the Residual Energy for resource *i* during Dispatch ~~i~~Interval *k* in Settlement Interval *o* of Settlement Period *h* for bid segment *m.*

D 3.59 **$OOS_PRICE_{i,h,o,k,L}$ – $/MWh**

The ~~s~~Settlement price for the Instructed Out of Stack Energy for resource *i* during Dispatch ~~i~~Interval *k* in Settlement Interval *o* of Settlement Period *h* for index number *L*.

***

D 3.61 **$IIE_PREDISPATCH_{i,h,p}$ – MWh**

The Settlement Period~~ly~~ pre-dispatched Energy for resource *i* during Dispatch ~~i~~Interval *p* of Settlement Period *h*.

***

D 3.71 **$UIE_{i,h,o}$ – MWh**

The total Uninstructed Imbalance Energy from resource *i* during Settlement ~~i~~Interval *o* of Settlement Period *h.*

D 3.72 **$UIE_1_{i,h,o}$ – MWh**

The Uninstructed Imbalance Energy attributed to non-compliance of *IIE_ECON* from resource *i* during Settlement ~~i~~Interval *o* of Settlement Period *h.*

***

D 3.75 **$ZONAL_EX_POST_PRICE_{j,h,o}$ – $/MWh**

The energy weighted average ~~e~~Ex ~~p~~Post ~~p~~Price for Imbalance Energy for Zone *j* in Settlement Interval *o* for Settlement Period *h.*

***

D 3.79 **$MR_ML_{i,h,o}$ – $**

The expected ~~r~~Real- ~~t~~Time ~~m~~Market revenue from Minimum Load Energy for resource *i* in Settlement Interval *o* for Settlement Period *h.*

***

D 3.86 **$BID_COST_RIE_{i,h,o}$ – $**

The bid costs for RIE for resource *i* in Settlement Period *h* for Settlement ~~i~~Interval *o.*

D 3.87 **$PREDISPATCH_PMT_{i,h,o}$ – $**

The unrecovered bid cost payment for a~~n~~ Settlement Period~~ly~~ pre-dispatched System Resource *i* in Settlement Interval *o* for Settlement Period *h.*

***

D 3.93 **$OOS_P_{i,h,o,k,L}$ – MWh**

The incremental Out of sStack Energy for resource *i* during Dispatch iInterval *k* in Settlement Interval *o* of Settlement Period *h* for index number *L*.

D 3.94 **$OOS_N_{i,h,o,k,L}$ – MWh**

The decremental Out of Stack Energy for resource *i* during Dispatch iInterval *k* in Settlement Interval *o* of Settlement Period *h* for index number *L*.

***

APPENDIX E

USAGE CHARGE COMPUTATION

***

E 2.3.3 **Debits to Participating TOs and FTR Holders and Debits/Rebates to Scheduling Coordinators**

If, after the close of the Day-Ahead Market, Participating TOs instruct the ISO to reduce interface limits based on operating conditions or an unscheduled transmission oOutage occurs and as a result of either of those events, Congestion is increased and Available Transfer Capacity is decreased in the Inter-Zonal Interface in the Hour-Ahead Market, the (L_{yth} - L_{ytd}) will be negative. In this case:

(a) Participating TOs and FTR Holders will be charged for the Usage Charge payments they received for the relevant Trading Interval t in the Day-Ahead Market with respect to the reduced interface limits;

(b) Any Scheduling Coordinator whose Schedule was adjusted for the relevant Trading Interval t in the Hour-Ahead Market due to the reduced interface limits will be credited with μ_{yth} for each MW of the adjustment; and

(c) Each Scheduling Coordinator will be charged an amount equal to it proportionate share, based on Schedules in the Day-Ahead Market in the direction of Congestion, of the difference between $\mu_{yth}(L_{yth} - L_{ytd})$ and the total amount charged to Participating TOs and FTR Holders in accordance with item (a) above.

The ISO will issue a notice to Scheduling Coordinators of the operating hour, and extent, for which the derate will apply in the relevant Hour-Ahead Markets. The timing and form of such notices shall be set forth in ISO procedures.

***

E 3.8 **μ_{ytd} ($/MW)**

The Day-Ahead Congestion price (shadow price) at Inter-Zonal iInterface y for Trading Interval t. This price is calculated by the ISO's Congestion Management computer optimization algorithm.

***

APPENDIX F

WHEELING ACCESS CHARGES COMPUTATION

F 1 **Purpose of Charge**

The Wheeling Access Charge is paid by Scheduling Coordinators for Wheeling as set forth in Section 7.1.4 of the ISO Tariff. The ISO will collect the Wheeling revenues from Scheduling Coordinators on a Trading Interval basis and repay these to the Participating TOs based on the ratio of each Participating TO's Transmission Revenue Requirement to the sum of all Participating TOs' Revenue rRequirements.

***

F 2.1.1 **Wheeling Access Charge**

The Wheeling Access Charge for each Participating TO shall be as specified in sSection 7.1.4 of the ISO Tariff.

***

APPENDIX G

VOLTAGE SUPPORT and BLACK START CHARGES COMPUTATION

***

G 1.2 All Generating Units are required by the ISO Tariff to provide reactive power by operating within a power factor range of 0.90 lag and 0.95 lead. Additional short--term Voltage Support required by the ISO is referred to as supplemental reactive power. If the ISO requires the

delivery of this supplemental reactive power by instructing a Generating Unit to operate outside its mandatory MVar range, the Scheduling Coordinator representing this Generating Unit will only receive compensation if it is necessary to reduce the MW output to achieve the MVar instructed output. Supplemental reactive power charges to Scheduling Coordinators are made on a Trading Interval basis. As of the ISO Operations Date the ISO will contract for long-term Voltage Support Service with the Owner of Reliability Must-Run Units under Reliability Must-Run Contracts.

***

G 2 Fundamental formulae

G 2.1 Payments to Scheduling Coordinators for providing Voltage Support

Payments to Scheduling Coordinators for additional Voltage Support service comprise:

G 2.1.1 Lost Opportunity Cost Payments (supplemental reactive power) to Scheduling Coordinators for Generating Units

When the ISO obtains additional Voltage Support by instructing a Generating Unit to operate outside its mandatory MVar range by reducing its MW output the ISO will select Generating Units based on their Supplemental Energy Bids ($/MWh). Subject to any locational requirements the ISO will select the Generating Unit with the highest decremental Supplemental Energy Bid to reduce MW output by such amount as is necessary to achieve the instructed MVar reactive energy production. Each Trading Interval the ISO will pay Scheduling Coordinator j for that Generating Unit i in Zone x, the lost opportunity cost ($) resulting from the reduction of MW output in Trading Interval t in accordance with the following formula:

$$VSST_{xijt} = Max\ \{0, P_{xt} - Sup_{xdecit}\} * DEC_{xit}$$

G 2.1.2 Long-term contract payments to Scheduling Coordinators for Reliability Must-Run Units for Generating Units and other Voltage Support Equipment

The ISO will pay Scheduling Coordinator j for the provision of Voltage Support from its Reliability Must-Run Units located in Zone x in month m a sum ($VSLT_{xjm}$) consisting of:

(a) the total of the Ancillary Service Pre-empted Dispatch Payments if the ISO has decreased the output of the Reliability Must-Run Units for the provision of Voltage Support outside the power factor range of the Reliability Must-Run Unit in any Trading Interval in month m and/or

(b) (if applicable) the total payments for the provision of Voltage Support in month m requested by the ISO from the synchronous condensers of the Reliability Must-Run Units,

calculated in each case in accordance with the terms of the relevant Reliability Must-Run Contract. Data on these payments will not be generated by the ISO. Such data will be based on the invoices issued by the Owners of Reliability Must-Run Generating Units pursuant to their Reliability Must-Run Contracts and will be verified by the ISO.

G 2.2 Charges to Scheduling Coordinators for Voltage Support

G 2.2.1 User Rate

The user rate ($/MWh) for the lost opportunity cost for ~~v~~Voltage ~~s~~Support referred to in G_2.1.1 in Zone x for Trading Interval t will be calculated using the following formula:

$$VSSTRate_{xt} = \frac{\sum_{ij} VSST_{xijt}}{\sum_{j} QChargeVS_{xjt}}$$

The user rate ($/MWh) for month m for long-~~-~~term ~~v~~Voltage ~~s~~Support referred to in G_2.1.2 in Zone x will be calculated using the following formula:

$$VSSTRate_{xm} = \frac{\sum_{j} VSLT_{xjm}}{\sum_{jm} QChargeVS_{xjt}}$$

G 2.2.2 Voltage Support Charges

The lost opportunity cost Voltage Support charge ($) payable to recover the sums under G_2.1.1 for Zone x for Trading Interval t for Scheduling Coordinator j will be calculated using the following formula:

$$VSSTCharge_{xjt} = VSSTRate_{xt} * QChargeVS_{xjt}$$

The monthly long-~~-~~term ~~v~~Voltage ~~s~~Support charge ($) payable to recover sums under G_2.1.2 for Zone x for month m for Scheduling Coordinator j will be calculated using the following formula:

$$VSLTCharge_{xjm} = VSLTRate_{xm} * \sum_{m} QChargeVS_{xjt}$$

***

G 2.4 Charges to Scheduling Coordinators for Black Start

G 2.4.1 User Rate

The user rate ($/MWh) for Black Start Energy payments referred to in G 2.3.1 and G_2.3.2 for Trading Interval t will be calculated using the following formula:

$$BSRate_t = \frac{\sum_{ij} BSEn_{ijt}}{\sum_j QChargeBlackStart_{jt}}$$

G 2.4.2 Black Start Charges

The user charge ($/MWh) for Black Start Energy to recover the costs of payments under G_2.3.1 and G_2.3.2 for Trading Interval t for Scheduling Coordinator j will be calculated using the following formula:

$$BSCharge_{jt} = BSRate_t * QChargeBlackStart_{jt}$$

G 3 Meaning of Terms in the Formulae

G 3.1 $VSST_{xijt}$ ($)

The lost opportunity cost paid by the ISO to Scheduling Coordinator j for Generating Unit i in Zone x, resulting from the reduction of MW output in Trading Interval t.

G 3.2 P_{xt} ($/MWh)

The Hourly Ex Post ~~p~~Price for Imbalance Energy in Trading Interval t in Zone x.

G 3.3 Sup_{xdecit} ($/MWh)

The Supplemental Energy Bid submitted by Scheduling Coordinator j for Generating Unit i in Zone x in Trading Interval t, whose output is reduced by the ISO to provide additional short-term Voltage Support.

G 3.4 Dec_{xit} (MW)

The reduction in MW by Scheduling Coordinator j for Generating Unit i in Zone x in Trading Interval t, in order to provide short-term additional Voltage Support.

***

G 3.7 $VSLTRate_{xm}$ ($/MWh)

The monthly long-term ~~v~~Voltage ~~s~~Support user rate charged by the ISO to Scheduling Coordinators for month m for Zone x.

***

G 3.10 **$VSLTCharge_{xjm}$ ($)**

The long-term charge for ~~v~~Voltage ~~s~~Support for month m for Zone x for Scheduling Coordinator j.

***

G 3.15 **$BSRate_t$ ($/MWh)**

The Black Start Energy ~~P~~payment user rate charged by the ISO to Scheduling Coordinators for Trading Interval t.

***

ANNEX 1

SETTLEMENT AND BILLING OF

RELIABILITY MUST-RUN CHARGES AND PAYMENTS

***

1.2.3 Special Definitions for this Annex

In this Annex the following words and expressions shall have the following meanings:

"Adjusted RMR Invoice" means the monthly invoice issued by the RMR Owner to the ISO for adjustments made to the Revised Estimated RMR Invoice pursuant to the RMR Contract, reflecting actual data for the billing month.

"Business Day" shall have the meaning ascribed to it in the RMR Contract.

"Estimated RMR Invoice" means the monthly invoice issued by the RMR Owner to the ISO for estimated RMR Payments or Refunds pursuant to the RMR Contract.

"Facility Trust Account" means, for each RMR Contract, the account established and operated by the ISO to and from which all payments under this Annex shall be made. Each Facility Trust Account will have two segregated commercial bank accounts, a RMR Owner Facility Trust Account and a Responsible Utility Facility Trust Account.

~~**"ISO Home Page"** means the ISO internet home page at http://www.caiso.com or such other internet address as the ISO shall publish from time to time.~~

~~**"ISO Invoice"** means the invoices issued by the ISO to the Responsible Utilities or RMR Owners based on the Revised Estimated RMR Invoice and the Revised Adjusted RMR Invoice.~~

"Prior Period Change" means any correction, surcharge, credit, refund or other adjustment pertaining to a billing month which is discovered after the Revised Adjusted RMR Invoice for such billing month has been issued.

"Prior Period Change Worksheet" means a worksheet prepared by the RMR Owner and submitted to the ISO following discovery of a necessary change to an RMR invoice after the Revised Adjusted RMR Invoice for the billing month has been issued.

"Responsible Utility Facility Trust Account" means a segregated commercial bank account under the Facility Trust Account containing funds held in trust for the Responsible Utility.

~~**"Revised Adjusted RMR Invoice"** means the monthly invoice issued by the RMR Owner to the ISO pursuant to the RMR Contract reflecting any appropriate revisions to the Adjusted RMR Invoice based on the ISO's validation and actual data for the billing month.~~

~~**"Revised Estimated RMR Invoice"** means the monthly invoice issued by the RMR Owner to the ISO pursuant to the RMR Contract reflecting appropriate revisions to the Estimated RMR Invoice based on the ISO's validation of the Estimated RMR Invoice.~~

~~**"RMR Charge"** means the sum payable by the Responsible Utility to the ISO pursuant to Section 5.2.7 of the ISO Tariff for the costs, net of all applicable credits, incurred under the RMR Contract.~~

~~**"RMR Contract"** means the Must-Run Service Agreement between the RMR Owner and the ISO.~~

"RMR Invoice" means any Estimated RMR Invoice, Revised Estimated RMR Invoice, Adjusted RMR Invoice, or Revised Adjusted RMR Invoice.

"RMR Owner Facility Trust Account" means a segregated commercial bank account under the Facility Trust Account containing funds held in trust for the RMR Owner.

"RMR Payment" means any amounts which the ISO is obligated to pay to RMR Owners under RMR Contracts, net of any applicable credits under RMR Contracts.

"RMR Payments Calendar" means the Payments Calendar issued by the ISO pursuant to ~~s~~Section 3 of this Annex 1.

"RMR Refund" means any amounts which RMR Owners are obligated to pay the ISO and the ISO is obligated to pay Responsible Utilities under RMR Contracts, or resulting from an order by the Federal Energy Regulatory Commission, for deposit into the Responsible Utility Facility Trust Account.

"RMR Security" means the form of security provided by a Responsible Utility to cover its liability under this Annex pursuant to Section 5.2.7.3 of the ISO Tariff.

***

ISO METERING PROTOCOL (MP)

***

MP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meanings set opposite them:

"Authorized Users" means a person or an entity identified as an authorized user in a meter service agreement between the ISO and an ISO Metered Entity or a meter service agreement between the ISO and a SC.

"Certificate of Compliance" means a certificate issued by the ISO which states that the Metering Facilities referred to in the certificate satisfy the certification criteria for Metering Facilities contained in the ISO Tariff and this Protocol.

"Check Meter" means a redundant revenue quality meter which is identical to and of equal accuracy to the primary revenue quality meter connected at the same metering point which must be certified in accordance with the ISO Tariff and this Protocol.

"Compatible Meter Data Server" means a meter data acquisition and processing system which is capable of passing Meter Data and/or Settlement Quality Meter Data to MDAS via File Transfer Protocol (FTP) and which has been certified in accordance with this Protocol by the ISO or its authorized representative.

~~**"ISO Home Page"** means the ISO internet home page at http://www.caiso.com/iso or such other address as the ISO shall publish from time to time.~~

~~**"ISO Authorized Inspector"** means a person authorized by the ISO to certify, test, inspect and audit the Metering Facilities in accordance with procedures established by the ISO pursuant to this Protocol.~~

~~**"ISO Metered Entity"** means:~~

~~(a) any one of the following entities that is directly connected to the ISO Controlled Grid:~~

~~i. a Generator other than a Generator that sells all of its Energy (excluding any Energy consumed by auxiliary load equipment electrically connected to that Generator at the same point) and Ancillary Services to the UDC in whose Service Area it is located;~~

~~ii. an Eligible Customer; or~~

~~iii. an End-User other than an End-User that purchases all of its Energy from the UDC in whose Service Area it is located; and~~

~~(b) any one of the following entities:~~

~~i. a Participating Generator;~~

~~ii. a Participating TO in relation to its Tie Point Meters with other TOs or Control Areas; or~~

~~iii. a Participating Load.~~

"ISO Metered Entity Meter Service Agreements" means the meter service agreements between the ISO and ISO Metered Entities.

"Line Loss Correction Factor" means the line loss correction factor as set forth in the Technical Specifications.

~~**"MCI Connected Entity Package"** means the package issued by MCI which describes the technical requirements for connections to WEnet.~~

"MDAS" means the ISO's revenue meter data acquisition and processing system.

"Meter Data Exchange Format" means the format for submitting Meter Data to the ISO which will be published by the ISO on the ISO Home Page or available on request to the Meter and Data Acquisition Manager, ISO Client Service Department.

"Meter Data Request Format" means the format for requesting Settlement Quality Meter Data from the ISO which will be published by the ISO on the ISO Home Page or available on request to the Meter and Data Acquisition Manager, ISO Client Service Department.

"Metering Facilities" means revenue quality meters, instrument transformers, secondary circuitry, secondary devices, meter data servers, related communication facilities and other related local equipment.

"MP Appendix" means an appendix to this Protocol.

"Proposal for Installation" means a written proposal submitted by an ISO Metered Entity to the ISO describing a proposal for the installation of additional Metering Facilities.

"SC" means Scheduling Coordinator.

"SC Meter Service Agreements" means the meter service agreements between the ISO and SCs.

~~**"Scheduling Coordinator Metered Entity"** or **"SC Metered Entity"** means a Generator, Eligible Customer or End-User that is not an ISO Metered Entity.~~

"Technical Specifications" means Appendices B to G (inclusive) of this Protocol.

"Transformer Loss Correction Factor" means the transformer loss correction factor as set forth in the Technical Specifications to be applied to revenue quality meters of ISO Metered Entities which are installed on the low voltage side of step-up transformers.

MP 1.2.3 Rules of Interpretation

The following rules of interpretation and conventions have been adopted in this Protocol:

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

(e) Any reference to a day, week, month or year is a reference to a calendar day, week, month or year except that a reference to a ~~b~~Business ~~d~~Day shall mean a day on which the banks in California are open for business.

***

MP 2.2.5 Format for Data Requests

SCs may obtain Settlement Quality Meter Data relating to the ISO Metered Entities they represent by directly polling MDAS using the Meter Data Request Format. The ISO will use its best efforts to ensure that such data is made available to SCs within 5 ~~b~~Business ~~d~~Days of the relevant Trading Day.

***

MP 3.3.4 Confirmation of Certification

On the written request of the ISO, each SC must give the ISO written confirmation that the Metering Facilities of each SC Metered Entity that it represents are certified in accordance with either the criteria of the relevant Local Regulatory Authority or the criteria prescribed by this Protocol within 5 ~~b~~Business ~~d~~Days of receiving a request from the ISO.

MP 3.3.5 ISO's Request for Certificates

The ISO may require SCs to provide it with a copy of any certificate issued by a Local Regulatory Authority in respect of the Metering

Facilities of each SC Metered Entity they represent. The SC must provide to the ISO a copy of such certificate within 5 ~~b~~Business ~~d~~Days of receiving the request for the certificate from the ISO.

***

MP 4.2.1 Requirement for Audit and Testing

(a) Audit and Testing by SC

Each SC shall at least annually conduct (or engage an independent, qualified entity to conduct) audits and tests of the Metering Facilities of the SC Metered Entities that it represents and the Meter Data provided to the SC in order to ensure compliance with all applicable requirements of any relevant Local Regulatory Authority. SCs shall undertake any other actions that are reasonable necessary to ensure the accuracy and integrity of the Settlement Quality Meter Data provided by them to the ISO.

(~~c~~b) Audit and Testing by ISO

Subject to any applicable Local Regulatory Authority requirements, the Metering Facilities and data handling and processing procedures of SCs and SC Metered Entities are subject to audit and testing by the ISO or an ISO Authorized Inspector in accordance with Section 10.6.7.7 of the ISO Tariff and this Protocol. Subject to any applicable Local Regulatory Authority requirements, the ISO will have the right to either conduct any audit or test it considers necessary or to witness such audit or test carried out by the SC, SC Metered Entity or an ISO Authorized Inspector engaged by the SC, SC Metered Entity or the ISO to carry out those audits or tests.

***

MP 5.1.3 Obligations of ISO Metered Entity

An ISO Metered Entity that is notified by the ISO that it is required to install additional Metering Facilities must:

(a) give the ISO written confirmation of receipt of that notice within 3 ~~b~~Business ~~d~~Days of receiving that notice;

(b) submit a Proposal for Installation to the ISO within 45 ~~b~~Business ~~d~~Days of receiving that notice. The Proposal for Installation must set out the following information:

i. a description of the proposed Metering Facilities to be installed (which shall include all relevant schematic drawings and one-line drawings);

ii. a proposed timetable for the installation; and

iii. any other information requested by the ISO in the notice referred to in MP 5.1.2.

***

MP 5.1.7 Rejection

If the ISO rejects a Proposal for Installation, it will promptly notify the ISO Metered Entity that the Proposal for Installation has been rejected and set out in that notice the reason for its rejection. The ISO Metered Entity must submit to the ISO a revised Proposal for Installation within 14 ~~b~~Business ~~d~~Days of receiving such notice of rejection. If the ISO rejects for a second time a Proposal for Installation submitted by an ISO Metered Entity in respect of the same or similar notice issued by the ISO under MP 5.1.2, the ISO and the ISO Metered Entity will use all reasonable good faith efforts to reach agreement on the requirements and disputed items and in the absence of agreement either entity may refer the dispute to the ISO ADR Procedures.

***

MP 6.1.2 Repairs

If a revenue quality meter of an ISO Metered Entity requires repairs to ensure that it operates in accordance with the requirements of the ISO Tariff and this Protocol, the ISO Metered Entity must immediately notify the ISO of the need for repairing that meter and must ensure that those repairs are completed:

(a) where there is no Check Meter installed, within 12 hours of the notification to the ISO; or

(b) where there is a Check Meter installed, within 5 ~~b~~Business ~~d~~Days of the notification to the ISO.

During periods for which no Meter Data is available from a meter which has a current Certificate of Compliance, the ISO will substitute estimated meter data for that ISO Metered Entity using the estimation procedures referred to in MP 10.1. That estimated meter data will be used by the ISO in its Settlement and billing process.

In respect of Metering Facilities (other than a revenue quality meter) of an ISO Metered Entity that need repair, the ISO Metered Entity shall notify the ISO of that need and, after consultation with the ISO Metered Entity, the ISO will set the time period in which such repairs must be completed.

***

MP 11.2 Facilities Provided by ISO Metered Entities

ISO Metered Entities must provide the telecommunication facilities referred to in MP 11.2.1 to MP 11.2.3 inclusive to connect their Compatible Meter Data Servers to the WEnet POP. ~~The detailed requirements for this interface are described in the MCI Connected Entity Package.~~

***

MP 12 METER IDENTIFICATION

MP 12.1 SC Metered Entities

If a SC Metered Entity is required to identify its revenue quality meters by the relevant:

(a) Local Regulatory Authority; or

(b) UDC,

then the SC representing that SC Metered Entity must, at the ISO's request, provide the ISO with a copy of that information within 5 ~~b~~Business ~~d~~Days of a request by the ISO in a format to be prescribed by the ISO.

If a SC Metered Entity is not required by either the relevant Local Regulatory Authority or UDC to identify its revenue quality meters, the SC representing that SC Metered Entity shall maintain an accurate record of the revenue quality meter of each of the SC Metered Entities that it represents from time to time. The record maintained by SCs must include the information set out in the Technical Specifications. The SC must, at the ISO's request, provide the ISO with a copy of any information contained in that record within 5 ~~b~~Business ~~d~~Days of a request by the ISO in a format to be prescribed by the ISO.

***

MP 13.3 Procedure for Applying for Exemptions

All applications to the ISO for exemptions from compliance with the requirements of the ISO Tariff or this Protocol must be made in writing addressed to the Meter and Data Acquisition Manager, Client Service Department. The ISO will confirm receipt of each application it receives within 3 ~~b~~Business ~~d~~Days of receiving the application. The ISO will decide whether to grant the exemption within 45 ~~b~~Business ~~d~~Days of receiving the application. At any time during that period, the ISO may require the applicant to provide additional information in support of its application. The applicant must provide such additional information to the ISO within 5 ~~b~~Business ~~d~~Days of receiving the request for additional information or within such other period as the ISO

may notify to the applicant. If the ISO makes a request for additional information more than 40 ~~b~~Business ~~d~~Days after the date on which it received the application, the ISO will have an additional 7 ~~b~~Business ~~d~~Days after receiving that additional information in which to consider the application. If the applicant does not provide the additional information requested, the ISO may refuse the application in which case it will notify the applicant that its application has been rejected for failure to provide the additional information.

***

Metering Protocol

APPENDIX A

FAILURE OF ISO FACILITIES

***

A 2 Primary MDAS Master Station Completely Unavailable

A 2.1 Notification of Loss of Primary MDAS Master Station

In the event that the primary MDAS master station becomes completely unavailable, the ISO will use alternate communications to notify the redundant MDAS master station that the primary MDAS master station is unavailable. The ISO will post information on the situation on the WEenet. Additional voice notifications will be made as time permits.

***

APPENDIX G

ISO DATA VALIDATION, ESTIMATION AND EDITING PROCEDURES

This Appendix is provided for information purposes only, it gives an overview of the procedures that the ISO will use to validate, edit and estimate Meter Data received from ISO Metered Entities and, where an exemption applies, Meter Data received from SC Metered Entities.

G 1 Validation

G 1.1 Timing of Data Validation

Meter Data will be remotely retrieved via WEenet from ISO Metered Entities by MDAS on a daily basis. Validation will be performed on the new Meter Data as it is retrieved from the meter or Compatible Meter Data Server in order to detect:

- missing data;
- data that could be invalid based upon status information returned from the meter; or
- meter hardware or communication failure.

Additional validation will be performed on a daily basis to verify data against load patterns, check meters, schedules, MDAS load interval data and data obtained by SCADA.

***

ELIGIBLE INTERMITTENT RESOURCES PROTOCOL (EIRP)

***

EIRP 1.2 Definitions

EIRP 1.2.1 Master Definitions Supplement

Unless the context otherwise requires, any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is a reference to a Section or an Appendix of the ISO Tariff. References to EIRP are to this Protocol or to the stated paragraph of this Protocol.

EIRP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meanings set opposite them:

"Forecast Fee" means the charge imposed on a Participating Intermittent Resource pursuant to the terms of this Protocol and ISO Tariff Appendix F, Schedule 4.

"Hour-Ahead Forecast" means the Energy forecast to be used by the Scheduling Coordinator representing a Participating Intermittent Resource for its Preferred Hour-Ahead Schedule, in accordance with EIRP 5.

***

EIRP 2.4 Requirements After Certification

EIRP 2.4.1 Forecast Fee

Beginning on the date first certified, a Participating Intermittent Resource must pay the Forecast Fee for all metered Energy generated by the Participating Intermitted Resource over the duration of the commitment indicated in the letter of intent described in EIRP 2.2.1(c).

The amount of the Forecast Fee shall be determined so as to recover the projected annual costs related to developing Energy forecasting systems, generating forecasts, validating forecasts, and monitoring forecast performance, that are incurred by the ISO as a direct result of participation by Participating Intermittent Resources in ISO ~~m~~Markets, divided by the projected annual Energy production by all Participating Intermittent Resources.

The initial rate for the Forecast Fee, and all subsequent rate changes as may be necessary from time to time to recover costs incurred by the ISO for the forecasting conducted on the behalf of Participating Intermittent Resources, shall be posted on the ISO Home Page. In no event shall the level of the Forecast Fee exceed the amount specified in ISO Tariff Appendix F, Schedule 4.

***

EIRP 4.1 Hour-Ahead Forecast

The ISO shall develop expert, independent hourly forecasts of Energy generation on each Participating Intermittent Resource. A forecast shall be published each hour on the half hour for each of the next seven operating hours. Other forecasts, including a day-ahead forecast, may be developed at the ISO's discretion. The Scheduling Coordinator representing the Participating Intermittent Resource must use the Hour-Ahead Forecast

that is available 30 minutes prior to the deadline for submitting the Preferred Hour-Ahead Schedule as specified in SP 3.3.1.

The ISO shall use best efforts to provide reliable and timely forecasts. However, if the ISO fails to deliver the Hour-Ahead Forecast to the Scheduling Coordinator prior to 15 minutes before the deadline for submitting Preferred Hour-Ahead Schedules, then the Hour-Ahead Forecast shall be the most recent Energy forecast provided by the ISO to the Scheduling Coordinator for the operating hour for which Preferred Schedules are next due.

***

EIRP 5 SCHEDULING AND SETTLEMENT

EIRP 5.1 Schedules

Scheduling Coordinators shall be required to submit Preferred Hour-Ahead Energy Schedules (MWh) for the Generating Units that comprise each Participating Intermittent Resource that are identical, in the aggregate, to the Hour-Ahead Forecast published for that Participating Intermittent Resource (MWh).

***

UDP AGGREGATION PROTOCOL

***

UAP 2 SUBMITTAL OF A REQUEST FOR UDP AGGREGATION

Requests for UDP Aggregation are submitted to the ISO and must include the following documentation:

(1) A completed UDP Aggregation Request form, which is available for downloading on the ISO website;

(2) A simplified electrical one-line diagram, which illustrates each resource, the connection of the resources to each other and to the ISO Control Area Grid;

(3) For Custom UDP Aggregations, a detailed description that explains physical operating interrelationships between the units, or, if there are no interrelationships, how the units are compatible and why an aggregation of these units for the purpose of calculating ~~u~~Uninstructed ~~d~~Deviation ~~p~~Penalties is reasonable.

***

UAP 3.1.2 Additional Criteria

Additional eligibility criteria for a UDP Aggregation are as follows:

(1) Only Generating Units shall be eligible for UDP Aggregation. As a general rule, pump-generating Units (or a Physical Scheduling Plant [PSP] containing a pump-generating Unit) cannot be part of a UDP Aggregation. However, it is possible that generating Units could form a UDP Aggregation comprised entirely of pump-generating Units whose operation is uniform, that is, Units all operating in either Generation mode or all in pump mode, but never mixed.

(2) UDP Aggregations cannot include any of the following:

(a) Load;

(b) Condition 2 Reliability Must Run (RMR) Units;

(c) Participating Intermittent Resources;

(d) Generating Units less than 5 MW; or

(e) Generating Units that span active or inactive ~~c~~Congestion ~~z~~Zones.

(3) The resources must have ISO direct telemetry and must be fully compliant with the ISO's direct telemetry standards.

(4) The Generating Units must exhibit the same effectiveness factors (factors within +/-10%) for managing inter- and -intra-zonal ~~c~~Constraints, under "normal/all elements in service" conditions, as well as during most local transmission outages.

(5) Custom UDP Aggregations involving units not directly connecting to the ISO Controlled Grid must recognize the transfer limits and status of the intermediate local facilities.

***

Amendment 54 Compliance Filing

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ATTACHMENT C

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requirements, minimum and maximum dam reservoir levels for flood control purposes, and in-stream flow levels. In carrying out its functions, the ISO will comply with and will have the necessary authority to give instructions to Participating TOs and Market Participants to enable it to comply with requirements of environmental legislation and environmental agencies having authority over the ISO in relation to Environmental Dispatch and will expect that submitted Schedules will support compliance with the requirements of environmental legislation and environmental agencies having authority over Generators in relation to Environmental Dispatch. In contracting for Ancillary Services and Imbalance Energy the ISO will not act as principal but as agent for and on behalf of the relevant Scheduling Coordinators.

2.2.2 ISO Scheduling Responsibilities.

To fulfill its obligations with respect to scheduling Energy and Ancillary Services, the ISO shall:

(a) provide Scheduling Coordinators with operating information and system status on a Day-Ahead and Hour-Ahead, Zonal and/or Scheduling Point basis to enable Scheduling Coordinators to optimize Generation, Demand and the provision of Ancillary Services;

(b) determine whether Preferred Schedules submitted by Scheduling Coordinators meet the requirements of Section 2.2.7.2, and whether they will cause Congestion;

(c) prepare Suggested Adjusted Schedules on a Day-Ahead basis and Final Schedules on a Day-Ahead and Hour-Ahead basis;

(d) validate all Ancillary Services bids and self-provided Ancillary Services;

and certificates of deposit must cover all applicable outstanding and estimated liabilities under Section 2.2.7.3 and shall be in such form as the ISO may reasonably require from time to time by notice to Scheduling Coordinators, UDCs or MSSs. A Scheduling Coordinator, UDC or MSS which does not maintain an Approved Credit Rating shall be subject to the limitations on trading set out in Section 2.2.7.3. Notwithstanding anything to the contrary in the ISO Tariff, a Scheduling Coordinator or UDC that had an Approved Credit Rating on January 3, 2001, and is an Original Participating Transmission Owner or is a Scheduling Coordinator for an Original Participating Transmission Owner shall not be precluded by Section 2.2.7.3 from scheduling transactions that serve a UDC's Demand from –

(1) a resource that the UDC owns; and

(2) a resource that the UDC has under contract to serve its Demand.

2.2.3.3 Review of Creditworthiness.

The ISO may review the creditworthiness of any Scheduling Coordinator, UDC or MSS which delays or defaults in making payments due under the ISO Tariff and, as a consequence of that review, may require such Scheduling Coordinator, UDC or MSS, whether or not it has (or is deemed to have) an Approved Credit Rating, to provide credit support in the form of:

(ii) if the Scheduling Coordinator fails to pay any sum under this ISO Tariff and fails to remedy the default within a period of seven (7) days after the ISO has given written notice of the default; or

(iii) if the Scheduling Coordinator commits any other default under this ISO Tariff or any of the ISO Protocols which, if capable of being remedied, is not remedied within thirty (30) days after the ISO has given it written notice of the default; or

(b) by the Scheduling Coordinator on sixty (60) days written notice to the ISO, provided that such notice shall not be effective to terminate the SC Agreement until the Scheduling Coordinator has complied with all applicable requirements of Section 2.2.5.

The ISO shall, following termination of an SC Agreement and within thirty (30) days of being satisfied that no sums remain owing by the Scheduling Coordinator under the ISO Tariff, return or release to the Scheduling Coordinator, as appropriate, any money or credit support provided by such Scheduling Coordinator to the ISO under Section 2.2.3.2.

2.2.4.5.1 Pending acceptance of termination of service pursuant to Section 2.2.4.6.1 by FERC, the ISO will suspend the certification of a Scheduling Coordinator which has received a notice of termination under Section 2.2.4.5(a) and the Scheduling Coordinator will not be eligible to submit Schedules and bids for Energy and Ancillary Services to the ISO.

2.2.4.6 Notification of Termination. The ISO shall, promptly after providing written notice of default to a Scheduling Coordinator as specified in Section 2.2.4.5(a), notify the Scheduling Coordinators that could be required to represent End Use Eligible Customers

2.2.6.5 Scheduling Deliveries. Including in its Schedules to be submitted to the ISO under this ISO Tariff, the Demand, Generation and Transmission Losses necessary to give effect to trades with other Scheduling Coordinators;

2.2.6.6 Tracking and Settling Trades. Tracking and settling all intermediate trades among the entities for which it serves as Scheduling Coordinator;

2.2.6.7 Ancillary Services. Providing Ancillary Services in accordance with Section 2.5;

2.2.6.8 Annual and Weekly Forecasts. Submitting to the ISO the forecasted weekly peak Demand on the ISO Controlled Grid and the forecasted Generation capacity. The forecasts shall cover a period of twelve (12) months on a rolling basis;

2.2.6.9 ISO Protocols. Complying with all ISO Protocols and ensuring compliance by each of the Market Participants which it represents with all applicable provisions of the ISO Protocols;

2.2.6.10 Interruptible Imports. Identifying any Interruptible Imports included in its Schedules;

2.2.6.11 Participating Intermittent Resources. Submitting Schedules consistent with the ISO Protocols; and

2.2.6.12 Compliance with Environmental Constraints, Operating Permits and Applicable Law. Submitting Ancillary Services bids, Adjustment Bids and Supplemental Energy bids so that any service provided in accordance with such bids does not violate environmental constraints, operating permits or applicable law. All submitted bids must reflect resource limitations and other constraints as such are required to be reported to the ISO Control Center.

2.2.7 Operations of a Scheduling Coordinator.

2.2.7.1 Maintain Twenty-four (24) Hour Scheduling Centers. Each Scheduling Coordinator shall operate and maintain a twenty-four (24) hour, seven (7) days per week, scheduling center. Each Scheduling Coordinator shall designate a senior member of staff as its scheduling center manager who

Following the date on which a UDC or MSS commences operation, the UDC's or MSS's Scheduling Coordinator shall not be entitled to submit a Schedule to the ISO and the ISO may reject any Schedule submitted if, at the time of submission, the UDC's or MSS's ISO Security Amount is exceeded by the UDC's or MSS's estimated aggregate liability for Grid Management Charge, and/or High Voltage Access Charges and Transition Charges for which Settlement has not yet been made in accordance with Section 11.3. The ISO shall notify a UDC or MSS if at any time such outstanding liabilities exceed 90% of the relevant portion of the ISO Security Amount. For the purposes of estimating the UDC's or MSS's aggregate liability for High Voltage Access Charges and Transition Charges, the UDC's or MSS's liability shall be equal to the billed Demand use (in MWh) for a month in the UDC's or MSS's Service Area (including exports from the Service Area) multiplied by the ISO's estimated High Voltage Access Charge and Transition Charge for that month, as such estimated cost is notified by the ISO to UDCs and MSSs from time to time.

2.2.7.4 The ISO shall notify the relevant Scheduling Coordinator if it rejects a Schedule under Section 2.2.7.3 in which event the Scheduling Coordinator shall not be entitled to submit any further Schedules until it has demonstrated to the ISO's satisfaction that its ISO Security Amount has been increased sufficiently to avoid the limit on trading imposed under Section 2.2.7.3 from being exceeded.

2.2.7.5 The ISO may restrict, or suspend a Scheduling Coordinator's right to Schedule or require the Scheduling Coordinator to increase its ISO Security Amount if at any time such Scheduling Coordinator's liability for Imbalance Energy is determined by the ISO to be

excessive by comparison with the likely cost of the amount of Energy scheduled by the Scheduling Coordinator.

2.2.8 The Scheduling Process.

The ISO scheduling process is described for information purposes only in tabular form in Appendix C. The scheduling process by nature will need constant review and amendment as the market develops and matures and, therefore, is subject to change. The description in Appendix C aids understanding of the implementation and operation of the various markets administered by the ISO and is filed for information purposes only.

2.2.8.1 Preferred Schedule. A Preferred Schedule shall be submitted by each Scheduling Coordinator on a daily and/or hourly basis to the ISO. Scheduling Coordinators may also submit to the ISO, Ancillary Services bids in accordance with Section 2.5.10 and, where they elect to self-provide Ancillary Services pursuant to Section 2.5.20.1, an Ancillary Service schedule meeting the requirements set forth in Section 2.5.20.6. The Preferred Schedule shall also include an indication of which resources (Generation or Load) if any may be adjusted by the ISO to eliminate Congestion. On receipt of the Preferred Schedule in the Day-Ahead scheduling process, the ISO shall notify the Scheduling Coordinator of any specific Reliability Must-Run Units which have not been included in the Preferred Schedule but which the ISO requires to run in the next Trading Day. The ISO will also notify the Scheduling Coordinator of any Ancillary Services it requires from specific Reliability Must-Run Units under their Reliability Must-Run Contracts in the next Trading Day. If the ISO identifies mismatches in the scheduled quantity or location for any Inter-Scheduling Coordinator Energy Trade, it will notify the Scheduling Coordinators concerned and give them until a specified time, which will allow

changes to the Suggested Adjusted Schedules, all of the Suggested Adjusted Schedules shall become the Final Schedules. The Final Schedules shall serve as the basis for Settlement between the ISO and each Scheduling Coordinator.

2.2.9 Prohibition on Scheduling Across Out-of-Service Transmission Paths. Scheduling Coordinators shall not submit any Schedule using a transmission path for any Settlement Period for which the Operating Transfer Capability for that path is zero MW. The ISO shall reject Schedules submitted for transmission paths on which the Operating Transfer Capability is zero MW. If the Operating Transfer Capability of a transmission path is reduced to zero after Final Day-Ahead Schedules have been submitted, then, if time permits, the ISO shall direct the responsible Scheduling Coordinators to reduce all Schedules on such zero-rated transmission paths to zero in the Hour-Ahead Market. As necessary to comply with Applicable Reliability Criteria, the ISO shall reduce any non-zero Final Hour-Ahead Schedules across zero-rated transmission paths to zero after the close of the Hour-Ahead Market. No Usage Charges will be assessed, nor will any Usage Charges for counter-flow be paid, for Schedules across a path with an Operating Transfer Capability of zero.

2.2.10 Information to be Provided by the ISO to all Scheduling Coordinators.

By 6:00 p.m. two days prior to a Trading Day, the ISO shall publish on WEnet information, including the following to all Scheduling Coordinators for each Settlement Period of the Trading Day:

2.2.10.1 Scheduled Line Outages. Scheduled transmission line Outages;

2.2.10.2 [Not Used]

2.2.10.3 Forecast Loop Flow. Forecast Loop Flow over ISO Inter-Zonal Interfaces and Scheduling Points;

2.2.10.4 Advisory Demand Forecasts. Advisory Demand Forecasts by location;

2.2.11 Information to Be Submitted by Scheduling Coordinators to the ISO.

Each Preferred Schedule submitted by a Scheduling Coordinator shall represent its preferred mix of Generation to meet its Demand and account for Transmission Losses and must include the name and identification number of each Eligible Customer for whom a Demand Bid or an Adjustment Bid is submitted, as well as:

2.2.11.1 For Demand:

2.2.11.1.1 Designated Location Code. For all Demand the Location Code of the Take-Out Point;

2.2.11.1.2 Quantity at Take-Out Point. The aggregate quantity (in MWh) of Demand being served at each Take-Out Point for which a bid has been submitted;

2.2.11.1.3 Flexibility. Whether the Preferred Schedule is flexible for adjustment to eliminate Congestion;

2.2.11.1.4 Adjustment Bids. The MW and $/MWh values representing the Adjustment Bid curve for any Dispatchable Load.

2.2.11.2 For Generation:

2.2.11.2.1 Location of Generating Units. The Location Code of all Generating Units scheduled, if applicable, or the source Control Area and Scheduling Point;

2.2.11.2.2 Quantity Scheduled. The aggregate quantity (in MWh) being scheduled from each Generating Unit and System Resource;

2.2.11.2.3 Notification of Flexibility. Notification of whether the Preferred Schedule is flexible for adjustment to eliminate Congestion;

location, the ISO will adjust the Schedule containing the higher quantity to match the scheduled quantity of Energy in the other Schedule, except where the Schedule to be reduced contains only Inter-Scheduling Coordinator Energy Trades, in which case the ISO will adjust the other Schedule to match the Schedule containing the higher quantity. If there is a dispute between the Scheduling Coordinators as to whether the Inter-Scheduling Coordinator Energy Trade occurred or over its location, the ISO will remove the disputed trade from the Schedules in which it appears. The ISO will then balance the Schedules which are no longer Balanced Schedules by adjusting resources in the relevant Scheduling Coordinator's portfolio in accordance with the procedures detailed in the ISO Protocols.

2.2.11.3.5 The Generating Unit or Dispatchable Load that the source or recipient of Energy traded.

2.2.11.3.6 The MW and $/MWh values representing the Adjustment Bid for any Generating Unit or Dispatchable Load that is the source or recipient of Energy traded.

2.2.11.4 **For Self-Provided Ancillary Services:** Scheduling Coordinators electing to self-provide Ancillary Services shall supply the information referred to in Section 2.5.20.5 in relation to each Ancillary Service to be self-provided.

2.2.11.5 **For Interruptible Imports:** the quantity (in MWh) of Energy categorized as Interruptible Imports and whether the Scheduling Coordinator intends to self-provide the Operating Reserve required by Section 2.5.3.2 to cover such Interruptible Imports or to purchase such Operating Reserve from the ISO.

2.2.12 **Timing of Day-Ahead Scheduling.**

2.2.12.1 The ISO may in its sole discretion waive the timing requirements of this Section 2.2 where necessary to preserve System Reliability. The ISO may also waive the

2.2.12.2.3 ***RMR Market Option*** – This Section 2.2.12.2.3 provides how an Applicable RMR Owner electing the RMR Market Option shall satisfy its obligation to deliver RMR Energy.

2.2.12.2.3.1 For each hour for which an Applicable RMR Owner has selected the Market Option, the Applicable RMR Owner (i) may bid into a power exchange market any amount of the RMR Market Energy and (ii) may schedule as a bilateral Day-Ahead transaction any amount of RMR Market Energy.

The Preferred Day-Ahead Schedule of the Applicable RMR SC shall include as RMR Market Energy for each hour the sum of the amount awarded to the Applicable RMR Owner in any power exchange market for that hour and the amount scheduled as a bilateral Day-Ahead transaction for that hour. If the Preferred Day-Ahead Schedule of the Applicable RMR SC for any hour includes Adjustment Bids for the RMR Unit, the Adjustment Bid shall specify the RMR Market Energy as the minimum MW output to which the Applicable RMR SC will allow the RMR Unit to be redispatched for that hour.

Notwithstanding anything to the contrary in the RMR Contract, neither the Applicable RMR Owner nor the Applicable RMR SC shall be entitled to any payment from any source for RMR Market Energy that is not bid and scheduled as required by this Section 2.2.12.2.3. In the event that the RMR Market Energy is not delivered, (i) if the RMR Market Energy had been scheduled, the Applicable RMR Owner shall not be entitled to an Availability Payment under the RMR Contract and the Applicable RMR SC shall pay for the Imbalance Energy necessary to replace that RMR Market Energy, or (ii) if the RMR Market Energy had not been scheduled, the Applicable RMR Owner shall not be entitled to an Availability Payment under the RMR Contract and, if the variable costs saved by the Owner's failure to deliver the RMR Market Energy (which shall be equal to the Variable Cost Payment determined pursuant to Schedule C in the RMR Contract) are greater than the

foregone Availability Payment under the RMR Contract, the Applicable RMR Owner shall pay the difference between the variable costs saved and the Availability Payment.

2.2.12.2.3.2 If the Applicable RMR SC's Preferred Day-Ahead Schedule does not include the entire amount of RMR Market Energy for any hour, the Applicable RMR Owner shall bid all remaining RMR Market Energy for that hour, net of any RMR Energy the Applicable RMR Owner elects to provide through an Hour-Ahead bilateral transaction for that hour, into the next available power exchange market for such hour at zero dollars per MWh.

2.2.12.2.3.2.1 The Applicable RMR SC's Preferred Hour-Ahead Schedule for each hour shall include all RMR Market Energy specified in the RMR Dispatch Notice for that hour, except for the amount of RMR Energy that the Applicable RMR Owner was required to bid into the power exchange markets under Section 2.2.12.2.3.2 but was not awarded in such power exchange markets for such hour. If the Preferred Hour-Ahead Schedule of the Applicable RMR SC for any hour includes Adjustment Bids for the RMR Unit, the Adjustment Bid shall specify the RMR Market Energy as the minimum MW output to which the Applicable RMR SC will allow the RMR Unit to be redispatched for that hour.

2.2.12.2.3.3 Whether or not the RMR Energy is in a Final Schedule, the Applicable RMR Owner must deliver the RMR Energy pursuant to the RMR Dispatch Notice. If the RMR Owner has bid and scheduled the RMR Energy as required by this Section 2.2.12.2.3, any RMR Energy provided but not included in the Final Schedule will be paid as Uninstructed Imbalance Energy. Notwithstanding anything to the contrary in the RMR Contract, neither the Applicable RMR Owner nor the Applicable RMR SC shall be entitled to any payment from any source for RMR Market Energy that is not bid and scheduled as required by this Section 2.2.12.2.3.

2.2.12.2.4 If, at any time after 5:00 a.m. on the day before the Trading Day, the ISO determines that it requires additional Energy from specific Reliability Must-Run Units during the Trading Day, the ISO will notify Scheduling Coordinators for such Reliability Must-Run Units of the amount and time of the additional Energy requirements from such Reliability Must-Run Units (the "Supplemental RMR Dispatch Notice").

2.2.12.3 Demand Information. By 6:00 a.m. on the day preceding the Trading Day, each Scheduling Coordinator shall provide to the ISO a Demand Forecast specified by UDC Service Area for which it will schedule deliveries for each of the Settlement Periods of the following Trading Day. The ISO shall aggregate the Demand information by UDC Service Area and transmit the aggregate Demand information to each UDC serving such aggregate Demand.

2.2.12.4 The Preferred Schedule of each Scheduling Coordinator for the following Trading Day shall be submitted at or prior to 10:00 a.m. on the day preceding the Trading Day together with any Adjustment Bids and Ancillary Services bids.

2.2.12.5 In submitting its Preferred Schedule, each Scheduling Coordinator shall notify the ISO of any Dispatchable Loads which are not scheduled but have submitted Adjustment Bids and are available for Dispatch at those same Adjustment Bids to assist in relieving Congestion.

2.2.12.6 ISO Analysis of Preferred Schedules. On receipt of the Preferred Schedules, the ISO will analyze the Preferred Schedules of Applicable RMR SCs to determine the compatibility of such Preferred Schedules with the RMR Dispatch Notices. If the ISO identifies mismatches in the scheduled quantity or location for any Inter-Scheduling Coordinator Energy Trade, it will notify the Scheduling Coordinators concerned

Preferred Schedules shall become Final Day-Ahead Schedules and the ISO shall notify Scheduling Coordinators accordingly.

2.2.12.8.2 Use of Congestion Management for Final Schedule. Subsequent to receiving Revised Schedules if the ISO identifies Congestion on the ISO Controlled Grid, it shall use the Congestion Management provisions of this ISO Tariff and the ISO Protocols to develop the Final Day-Ahead Schedules.

2.2.13 Timing of Hour-Ahead Scheduling.

2.2.13.1 Submission of Preferred Schedule. Each Scheduling Coordinator's Preferred Schedule for each Settlement Period during a Trading Day together with any additional or updated Adjustment Bids or Ancillary Services bids shall be submitted at least two hours and fifteen minutes (*i.e.*, 135 minutes) prior to the commencement of that Settlement Period.

2.2.13.1.1 Statements in Preferred Schedule. In submitting its Preferred Schedule, each Scheduling Coordinator may submit Adjustment Bids for use in the Hour-Ahead Market to assist in relieving Congestion.

2.2.13.1.2 Final Hour-Ahead Schedule Submission. Each Hour-Ahead Schedule shall indicate the changes which the relevant Scheduling Coordinator wishes to make to the Final Day-Ahead Schedule.

2.2.13.2 ISO Analysis of Preferred Schedules. The ISO shall analyze the combined Preferred Schedules submitted by all Scheduling Coordinators to forecast the probability of Congestion being caused by the Preferred Schedules.

2.2.13.2.1 Preferred Schedules Become Final Hour-Ahead Schedules. If the ISO identifies no Congestion on the ISO Controlled Grid, the Preferred Schedules shall

become Final Hour-Ahead Schedules and the ISO shall notify Scheduling Coordinators accordingly.

2.2.13.2.2 Congestion Management Provisions for Final Hour-Ahead Schedules. If the ISO identifies Congestion, it shall use the Congestion Management provisions of Section 7.2 of this ISO Tariff and the ISO Scheduling Protocol to develop the Final Hour-Ahead Schedules.

2.2.13.2.3 [Not Used]

2.2.16 Relationship Between ISO and Participating Loads

The ISO shall only accept bids for Supplemental Energy or Ancillary Services, or Schedules for self-provision of Ancillary Services, from Loads if such Loads are Participating Loads which meet standards adopted by the ISO and published on the ISO Home Page. The ISO shall not schedule Energy or Ancillary Services from a Participating Load other than through a Scheduling Coordinator.

2.2.17 Relationship Between ISO and Eligible Intermittent Resources and Between the ISO and Participating Intermittent Resources

The ISO shall not schedule Energy from an Eligible Intermittent Resource other than through a Scheduling Coordinator. Settlement with Participating Intermittent Resources that meet the scheduling obligations established in the ISO Protocols shall be as provided in this ISO Tariff. No Adjustment Bids or Supplemental Energy bids may be submitted on behalf of Participating Intermittent Resources. Any Eligible Intermittent Resource that is not a Participating Intermittent Resource, or any Participating Intermittent Resource for which Adjustment Bids or Supplemental Energy bids are submitted, or that fails to meet the scheduling obligations established in the ISO Protocols, shall be scheduled and settled as a Generating Unit for the associated Settlement Periods (except that the Forecasting Fee shall apply in such Settlement Periods).

2.3 System Operations under Normal and Emergency Operating Conditions.

2.3.1 ISO Control Center Operations.

2.3.1.1 ISO Control Center.

2.3.1.1.1 Establish ISO Control Center. The ISO shall establish a WECC approved Control Area and control center to direct the operation of all facilities forming part of the ISO Controlled Grid, Reliability Must-Run Units and Generating Units providing Ancillary Services.

2.3.1.1.2 Establish Back-up Control Facility. The ISO shall establish back-up control facilities remote from the ISO Control Center sufficient to enable the ISO to continue to direct the operation of the ISO Controlled Grid, Reliability Must-Run Units and Generating Units providing Ancillary Services in the event of the ISO Control Center becoming inoperable.

2.3.1.1.3 ISO Control Center Authorities. The ISO shall have full authority, subject to Section 2.3.1.2, to direct the operation of the facilities referred to in Section 2.3.1.1.2 including (without limitation), to:

(a) direct the physical operation by the Participating TOs of transmission facilities under the Operational Control of the ISO, including (without limitation) circuit

breakers, switches, voltage control equipment, protective relays, metering, and Load Shedding equipment;

(b) commit and dispatch Reliability Must-Run Units;

(c) order a change in operating status of auxiliary equipment required to control voltage or frequency;

(d) take any action it considers to be necessary consistent with Good Utility Practice to protect against uncontrolled losses of Load or Generation and/or equipment damage resulting from unforeseen occurrences;

(e) control the output of Generating Units that are selected to provide Ancillary Services and Imbalance Energy;

(f) dispatch Loads through direct Load control or other means at the ISO's discretion that are curtailable as an Ancillary Service; and

(g) procure Supplemental Energy.

2.3.1.1.4 Coordination and Approval for Outages. The ISO shall have authority to coordinate and approve Outages and returns to service of all facilities comprised in the ISO Controlled Grid and Reliability Must-Run Units in accordance with Section 2.3.3.

2.3.1.1.5 Responsibility for Authorized Work on Facilities. The ISO shall have authority to approve requests by Participating TOs to work on all energized transmission equipment under the Operational Control of the ISO.

2.3.1.1.6 The ISO shall be the WECC reliability coordinator for the ISO Controlled Grid.

2.3.1.2 Market Participant Responsibilities.

2.3.1.2.1 Comply with Operating Orders Issued. With respect to this Section 2.3.1.2, all Market Participants within the ISO Control Area shall comply fully and promptly with the ISO's operating orders, unless such operation would impair public health or safety. The ISO will honor the terms of Existing Contracts, provided that, in a System Emergency and circumstances in which the ISO considers that a System Emergency is imminent or threatened, holders of Existing Rights must follow ISO operating orders even if those operating orders directly conflict with the terms of Existing Contracts. For this purpose ISO operating orders to shed Load shall not be considered as an impairment to public health or safety.

2.3.1.2.2 Implementation of Instructions. All Market Participants shall respond to ISO instructions with no more delay than specified in the response times set out in the ISO Protocols.

2.3.1.3 Operating Reliability Criteria.

2.3.1.3.1 The ISO shall exercise Operational Control over the ISO Controlled Grid to meet planning and Operating Reserve criteria no less stringent than those established by WECC and NERC as those standards may be modified from time to time, and Local Reliability Criteria that are in existence on the ISO Operations Date and have been submitted to the ISO by each Participating TO pursuant to Section 2.2.1(v) of the TCA. All Market Participants and the ISO shall comply with the ISO Reliability Criteria, standards, and procedures.

2.3.1.3.2 The ISO may establish planning and Operating Reserve criteria more stringent than those established by WECC and NERC or revise the Local Reliability Criteria subject to and in accordance with the provisions of the TCA.

Emergency. A declaration by the ISO of a System Emergency shall be binding on all Market Participants until the ISO announces that the System Emergency no longer exists.

2.3.2.2 Emergency Procedures. In the event of a System Emergency, the ISO shall take such action as it considers necessary to preserve or restore stable operation of the ISO Controlled Grid. The ISO shall act in accordance with Good Utility Practice to preserve or restore reliable, safe and efficient service as quickly as reasonably practicable. The ISO shall keep system operators in adjacent Control Areas informed as to the nature and extent of the System Emergency in accordance with WECC procedures and, where practicable, shall additionally keep the Market Participants within the Control Area informed.

2.3.2.3 Intervention in Market Operations. The ISO may intervene in the operation of the Day-Ahead Market, the Hour-Ahead Market or the Real Time Market and set the Administrative Price, if the ISO determines that such intervention is necessary in order to contain or correct a System Emergency as follows.

2.3.2.3.1 The ISO will not intervene in the operation of the Day-Ahead Market unless there has been a total or major collapse of the ISO Controlled Grid and the ISO is in the process of restoring it.

2.3.2.3.2 Before any such intervention the ISO must (in the following order): (a) dispatch all scheduled Generation and all other Generation offered or available to it regardless of price (including all Adjustment Bids, Supplemental Energy bids, Ancillary Services and reserves); (b) dispatch all interruptible Loads made available by UDCs to the ISO in accordance with the relevant agreements with UDCs; (c) dispatch or curtail all price-responsive Demand that has been bid into any of the markets and exercise its rights under all load curtailment contracts available to it; (d) exercise Load

2.3.2.7 Further Obligations Relating to System Emergencies. The ISO and Participating TOs shall comply with their obligations in Section 9 of the TCA. The ISO and UDCs shall comply with their obligations in Section 4 of this ISO Tariff. The ISO and Generators shall comply with their obligations in Section 5 of this ISO Tariff.

2.3.2.8 Use of Load Curtailment Programs.

2.3.2.8.1 Use of UDC's Existing Load Curtailment Programs. As an additional resource for managing System Emergencies, the ISO will, subject to Section 2.1.3, notify the UDCs when the conditions to implement their Load curtailment programs have been met in accordance with their terms. Each UDC shall by not later than October 1 of each year advise the ISO of the capabilities of its Load curtailment programs for the forthcoming year, and the conditions under which those capabilities may be exercised and shall give the ISO as much notice as reasonably practicable of any change to such programs.

2.3.2.8.2 Load Curtailment. A Scheduling Coordinator may specify that Loads will be reduced at specified Market Clearing Prices or offer the right to exercise Load curtailment to the ISO as an Ancillary Service or utilize Load curtailment itself (by way of self-provision of Ancillary Services) as Non-Spinning Reserve or Replacement Reserve. The ISO, at its discretion, may require direct control over such Curtailable Demand to assume response capability for managing System Emergencies. However, non-firm Loads shall not be eligible to provide Curtailable Demand if they are receiving incentives for interruption under existing programs approved by a Local Regulatory Authority, unless: a) participation in the ISO's Ancillary Services markets is specifically authorized by such Local Regulatory Authority, and b) there exist no contingencies on the availability, nor any unmitigated incentives encouraging prior curtailment, of such interruptible Load for Dispatch as Curtailable Demand as a result of the operation of such existing program.

2.3.3.3 Requests for Outages in Real-Time Operation. Requests for Outages of: (i) facilities that comprise the ISO Controlled Grid or (ii) Participating Generators in real-time operation shall be made by the Operator to the ISO Control Center. The ISO will not approve any Outage request made within seventy-two (72) hours of the requested Outage start time unless: (i) the requested Outage could not have been reasonably foreseen and scheduled through the Outage coordination process provided in Section 2.3.3; and (ii) the requested Outage will not compromise ISO Controlled Grid reliability.

2.3.3.4 Single Point of Contact. Requests for approvals and coordination of all Maintenance Outages (consistent with Section 2.3.3.1) will be through a single point of contact between the ISO Outage Coordination Office and each Operator. The single point of contact for the ISO and each Operator will be specified from time to time by the Operator and the ISO pursuant to the detailed procedures referred to in Section 2.3.3.5.

2.3.3.5 Maintenance Outage Planning. Each Operator shall, by not later than October 15 each year, provide the ISO with a proposed schedule of all Maintenance Outages it wishes to undertake in the following year. The proposed schedule shall include all of the Operator's transmission facilities that comprise the ISO Controlled Grid and Participating Generators. In the case of a Participating TO's transmission facilties, that proposed schedule shall be developed in consultation with the UDCs interconnected with that Participating TO's system and shall take account of each UDC's planned maintenance requirements. The nature of the information to be provided and the detailed Maintenance Outage Planning Procedure shall be established by the ISO and set out in an ISO Protocol. Either the ISO, pursuant to Section 2.3.3.6, or an Operator, subject to Section 2.3.3.5.4, may at any time request a change to an Approved

Participants and reflect the availability of the affected facilities in determining the availability of transmission capacity in the Hour-Ahead Market.

2.3.3.6 Maintenance Outage Requests by the ISO. The ISO Outage Coordination Office may at any time request a Maintenance Outage or a change to an Approved Maintenance Outage from an Operator if, in the opinion of the ISO Outage Coordination Office, the requested Maintenance Outage or change is required to secure the efficient use and reliable operation of the ISO Controlled Grid. In addition, the ISO Outage Coordination Office may, by providing notice no later than 5:00 a.m. of the day prior to the day upon which the Outage is scheduled to commence, direct the Operator to cancel an Approved Maintenance Outage, when necessary to preserve or maintain System Reliability or, with respect to Reliability Must-Run Units or facilities that form part of the ISO Controlled Grid, to avoid unduly significant market impacts that would arise of the Outage were to proceed as scheduled. The Operator, acting in accordance with Good Utility Practice, shall comply with the ISO's direction and the provisions of Sections 2.3.3.6.1 and 2.3.3.6.2 shall apply. The ISO shall give notice of any such direction to Market Participants prior to the deadline for submission of initial Preferred Day-Ahead Schedules for the day on which the Outage was to have commenced. For purposes of this section and Section 2.3.3.3, an "unduly significant market impact" means an unplanned event or circumstance (e.g., unseasonable weather, a Forced Outage of a facility, or other occurrence) that adversely affects the competitive nature and efficient workings of the ISO Markets, and is of such severity that a prudent Operator would not have scheduled a Maintenance Outage of its facility if the unplanned event or circumstance could have been anticipated.

2.3.3.9.3 The ISO Control Center shall coordinate any operational changes necessary to accommodate a Forced Outage and Market Participants shall comply with the ISO's instructions given for that purpose.

2.3.3.9.4 All Forced Outages shall be communicated by the ISO Control Center to Operators likely to be affected by the Outage using the same procedures adopted for Maintenance Outage coordination procedures.

2.3.3.9.5 Within forty-eight (48) hours of the commencement of a Forced Outage, the Operator shall provide to the ISO an explanation of the Forced Outage, including a description of the equipment failure or other cause and a description of all remedial actions taken by the Operator. Upon request of the ISO, Operators, and where applicable, Eligible Customers, Scheduling Coordinators, UDCs and MSSs promptly shall provide information requested by the ISO to enable the ISO to review the explanation submitted by the Operator and to prepare reports on Forced Outages. If the ISO determines that any Forced Outage may have been the result of gaming or other questionable behavior by the Operator, the ISO shall submit a report describing the basis for its determination to the FERC. The ISO shall consider the following factors when evaluating the Forced Outage to determine if the Forced Outage was the result of gaming or other questionable behavior by the Operator: 1) if the Forced Outage coincided with certain market conditions such that the Forced Outage may have influenced market prices or the cost of payments associated with out-of-sequence dispatches, out-of-market dispatches, or Real Time Market dispatches above the Marginal Proxy Clearing Price or Non-Emergency Clearing Price Limit, as applicable; 2) if the Forced Outage coincided with a change in the bids submitted for any units or resources controlled by the Operator or the Operator's Scheduling Coordinator; 3) if the ISO had recently rejected a request for an outage for, or to shut down, the Generating

Unit experiencing the Forced Outage; 4) if the timing or content of the notice of the Forced Outage provided to the ISO was inconsistent with subsequent reports of or the actual cause of the outage; 5) if the Forced Outage or the duration of the Forced Outage was inconsistent with the history or past performance of that Generating Unit or similar Generating Units; 6) if the Forced Outage created or exacerbated Congestion; 7) if the Forced Outage was extended with little or no notice; 8) if the Operator had other alternatives to resolve the problems leading to the Forced Outage; 9) if the Operator took reasonable action to minimize the duration of the Forced Outage; or 10) if the Operator failed to provide the ISO an explanation of the Forced Outage within forty-eight (48) hours or failed to provide any additional information or access to the generating facility requested by the ISO within a reasonable time.

2.3.3.10 Other Control Areas. The ISO Outage Coordination Office shall make all reasonable efforts to coordinate Outages involving other Control Areas or affecting an intertie, import or export capability not under the Operational Control of the ISO to the extent that they may affect the reliability of the ISO Controlled Grid.

2.3.3.11 Records. The ISO and all Operators shall develop procedures to keep a record of approved Maintenance Outages as they are implemented and to report the completion of approved Maintenance Outages.

2.3.4 Management of Overgeneration Conditions.

The ISO's management of Overgeneration relates only to real time. Overgeneration in real time will be mitigated by the ISO as follows; provided that the ISO Operator will have the discretion, if necessary to avoid a System Emergency, to eliminate one or more of the following steps.

2.3.5 Assurance of Adequate Generation and Transmission to meet Applicable Operating and Planning Reserve.

2.3.5.1 Generation Planning Reserve Criteria. Generation planning reserve criteria shall be met as follows:

2.3.5.1.1 On an annual basis, the ISO shall prepare a forecast of weekly Generation capacity and weekly peak Demand on the ISO Controlled Grid. This forecast shall cover a period of twelve months and be posted on the WEnet and the ISO may make the forecast available in other forms at the ISO's option.

2.3.5.1.2 If the forecast shows that the applicable WESCC/NERC Reliability Criteria can be met during peak Demand periods, then the ISO shall take no further action.

2.3.5.1.3 If the forecast shows that the applicable WECC/NERC Reliability Criteria cannot be met during peak Demand periods, then the ISO shall facilitate the development of market mechanisms to bring the ISO Controlled Grid during peak periods into compliance with the Applicable Reliability Criteria (or such more stringent criteria as the ISO may impose pursuant to Section 2.3.1.3.2). The ISO shall solicit bids for Replacement Reserve in the form of Ancillary Services, short-term Generation supply contracts of up to one (1) year with Generators, and Load curtailment contracts giving the ISO the right to reduce the Demands of those parties that win the contracts when there is insufficient Generation capacity to satisfy those Demands in addition to all other Demands. The curtailment contracts shall provide that the ISO's curtailment rights can only be exercised after all available Generation capacity has been fully utilized unless the exercise of such rights would allow the ISO to satisfy the Applicable Reliability Criteria at lower cost, and the curtailment rights shall not be exercised to stabilize or otherwise influence prices for power in the Energy markets.

2.3.5.1.4 If Replacement Reserve, short-term Generation supply contracts or curtailment contracts are required to meet Applicable Reliability Criteria, the ISO shall select the bids that permit the satisfaction of those Applicable Reliability Criteria at the lowest cost.

2.3.5.1.5 Notwithstanding the foregoing, if the ISO concludes that it may be unable to comply with the Applicable Reliability Criteria, the ISO shall, acting in accordance with Good Utility Practice, take such steps as it considers to be necessary to ensure compliance, including the negotiation of contracts through processes other than competitive solicitations.

2.3.5.1.6 The ISO may, in addition to the required annual forecast, publish a forecast of the peak Demands and Generation resources for two or more additional years. This forecast would be for information purposes to allow Market Participants to take appropriate steps to satisfy the Applicable Reliability Criteria, and would not be used by the ISO to determine whether additional resources are necessary.

2.3.5.1.7 In fulfilling its requirement to ensure that the applicable Generation planning reserve criteria are satisfied, the ISO shall rely to the maximum extent possible on market forces.

2.3.5.1.8 Except where and to the extent that such costs are recovered from Scheduling Coordinators pursuant to Section 2.5, and except as provided in Section 2.3.5.1.9, all costs incurred by the ISO in any hour pursuant to any contract entered into under this Section 2.3.5.1 shall be charged to each Scheduling Coordinator pro rata based upon the same proportion as the Scheduling Coordinator's metered hourly Demand (including exports) bears to the total metered hourly Demand (including exports) served in that hour.

2.3.5.1.9 Costs incurred by the ISO pursuant to any contract entered into under this Section 2.3.5.1 for resources to meet any portion of the anticipated difference between

rights from an operational point of view; and (vi) does not require the ISO to interpret or underwrite the economics of the Existing Contract.

2.4.3.2 The ISO may refuse to accept Schedules submitted pursuant to Existing Contracts which do not meet the requirements of the principles, protocols and rules referred to in this Section 2.4.3 and Section 2.4.4.

2.4.3.3 The ISO will, if requested, advise parties to Existing Contracts regarding the operational aspects of any Existing Contract renegotiations that they undertake.

2.4.4 ISO Administration of Existing Contracts for Transmission Service.

2.4.4.1 Continuation of Rights and Obligations of Non-Participating TOs Under Existing Contracts.

2.4.4.1.1 The transmission service rights and obligations of Non-Participating TOs under Existing Contracts, including all terms, conditions and rates of the Existing Contracts, as they may change from time to time under the terms of the Existing Contracts, will continue to be honored by the parties to those contracts, for the duration of those contracts. For the purpose of Section 2.4.4, the transmission service rights of Non-Participating TOs are called "Existing Rights."

2.4.4.1.2 If a Participating TO is a party to an Existing Contract under which Existing Rights are provided, the Participating TO shall attempt to negotiate changes to the Existing Contract to align the contract's scheduling and operating provisions with the ISO's scheduling and operational procedures, rules and protocols, to align operations under the contract with ISO operations, and to minimize the contract parties' costs of administering the contract while preserving their financial rights and obligations as defined in Section 2.4.4.3.

2.5 Ancillary Services.

2.5.1 Scope.

The ISO shall be responsible for ensuring that there are sufficient Ancillary Services available to maintain the reliability of the ISO Controlled Grid consistent with WECC and NERC criteria. The ISO's Ancillary Services requirements may be self-provided by Scheduling Coordinators. Those Ancillary Services which the ISO requires to be available but which are not being self-provided will be competitively procured by the ISO from Scheduling Coordinators in the Day-Ahead Market, Hour-Ahead Market and in real time or by longer-term contracts. The ISO will manage both ISO procured and self-provided Ancillary Services as part of the real-time Dispatch. The ISO will calculate payments for Ancillary Services to Scheduling Coordinators and charge the cost to Scheduling Coordinators.

For purposes of this ISO Tariff, Ancillary Services are: (i) Regulation, (ii) Spinning Reserve, (iii) Non-Spinning Reserve, (iv) Replacement Reserve, (v) Voltage Support, and (vi) Black Start capability. Bids for Non-Spinning Reserve and Replacement Reserve may be submitted by the Demand-side as well as by owners of Generation. Identification of specific services in this ISO Tariff shall not preclude development of additional interconnected operation services over time. The ISO and Market Participants will seek to develop additional categories of these unbundled services over time as the operation of the ISO Controlled Grid matures.

2.5.2 Ancillary Services Standards.

All Ancillary Services shall meet the ISO's Ancillary Services standards.

2.5.2.1 Determination of Ancillary Service Standards. The ISO shall set the required standard for each Ancillary Service necessary to maintain the reliable operation of the ISO

Controlled Grid. Ancillary Services standards shall be based on WECC Minimum Operating Reliability Criteria (MORC) and ISO Controlled Grid reliability requirements. The ISO Grid Operations Committee, in conjunction with the relevant reliability council (WECC), shall develop these Ancillary Services standards to determine reasonableness, cost effectiveness, and adherence to national and WECC standards. The standards developed by the ISO shall be used as a basis for determining the quantity and type of each Ancillary Service which the ISO requires to be available.

2.5.2.2 Time-frame For Revising Ancillary Service Standards. The ISO Technical Advisory Committee shall periodically undertake a review of the ISO Controlled Grid operation to determine any revision to the Ancillary Services standards to be used in the ISO Control Area. At a minimum the ISO Grid Operations Committee shall conduct such reviews to accommodate revisions to WECC and NERC standards. The ISO may adjust the Ancillary Services standards temporarily to take into account, among other things variations in system conditions, real-time Dispatch constraints, contingencies, and voltage and dynamic stability assessments. Where practicable, the ISO will provide notice, via the ISO Home Page, of any temporary adjustments to Ancillary Service standards by 6:00 p.m. two days ahead of the Trading Day to which the adjustment will apply.

2.5.3 Quantities of Ancillary Services Required.

For each of the Ancillary Services, the ISO shall determine the quantity and location of the Ancillary Service which is required and which must be under the direct Dispatch control of the ISO on an hourly basis each day. The ISO shall determine the quantities it requires as follows:

2.5.3.1 Regulation Service. The ISO shall maintain sufficient Generating Units immediately responsive to AGC in order to provide sufficient Regulation service to allow the system to meet WECC and NERC criteria.

2.5.3.2 Spinning And Non-Spinning Reserves. The ISO shall maintain minimum contingency Operating Reserve made up of Spinning Reserve and Non-Spinning Reserve in accordance with WECC MORC criteria equal to (a) 5% of the Demand to be met by Generation from hydroelectric resources plus 7% of the Demand to be met by Generation from other resources, or (b) the single largest Contingency, if this is greater or (c) by reference to such more stringent criteria as the ISO may determine from time to time. When the level of Operating Reserve is determined by Demand, the ISO shall not maintain Operating Reserve with respect to Demand covered by firm purchases from outside the ISO Control Area. In addition, the ISO shall maintain Operating Reserve equal to the total amount of Interruptible Imports scheduled by Scheduling Coordinators for any hour. Such additional Operating Reserve must either be self-provided or purchased from the ISO by Scheduling Coordinators. To the extent such additional Operating Reserve is self-provided by a Scheduling Coordinator, it may consist entirely of Non-Spinning Reserve. To the extent that such additional Operating Reserve is not self-provided by a Scheduling Coordinator, the ISO will procure the necessary amounts of Operating Reserve, but not necessarily entirely from Non-Spinning Reserve.

2.5.3.3 Replacement Reserve. The ISO shall make its determination of the required quantity of Replacement Reserve based on:

(a) historical analysis of the deviation between actual and Day-Ahead forecast Demand,

(b) historical patterns of unplanned Generating Unit Outages,

(c) historical patterns of shortfalls between Final Day-Ahead Schedules and actual Generation and Demand,

(d) historical patterns of unexpected transmission Outages, and

(e) such other factors affecting the ability of the ISO to maintain System Reliability as the ISO may from time to time determine.

The ISO shall have discretion to determine the quantity of Replacement Reserve it requires in each Zone.

2.5.3.4 Voltage Support.

The ISO shall determine on an hourly basis for each day the quantity and location of Voltage Support required to maintain voltage levels and reactive margins within WECC and NERC criteria using a power flow study based on the quantity and location of scheduled Demand. The ISO shall issue daily voltage schedules, which are required to be maintained for ISO Controlled Grid reliability. All other Generating Units shall comply with the power factor requirements set forth in contractual arrangements in effect on the ISO Operations Date, or, if no such contractual arrangements exist and the Generating Unit exists within the system of a Participating TO, the power factor requirements applicable under the Participating TO's TO Tariff or other tariff on file with the FERC.

All Participating Generators shall maintain the ISO specified voltage schedule at the transmission interconnection points to the extent possible while operating within the power factor range specified in their interconnection agreements or, for Regulatory Must-Take Generation, Regulatory Must-Run Generation and Reliability Must-Run Generation consistent with existing obligations. For Generating Units, that do not operate under one of these agreements, the minimum power factor range will be within a band of 0.90 lag

(producing VARs) and 0.95 lead (absorbing VARs) power factors. Participating Generators with Generating Units existing at the ISO Operations Date that are unable to meet this operating power factor requirement may apply to the ISO for an exemption. Prior to granting such an exemption, the ISO shall require the Participating TO or UDC to whose system the relevant Generating Units are interconnected to notify it of the existing contractual requirements for Voltage Support established prior to the ISO Operations Date for such Generating Units. Such requirements may be contained in CPUC Electric Rule 21 or the Interconnection Agreement with the Participating TO or UDC. The ISO shall not grant any exemption under this Section from such existing contractual requirements. The ISO shall be entitled to instruct Participating Generators to operate their Generating Units at specified points within their power factor ranges. Generators shall receive no compensation for operating within these specified ranges.

If the ISO requires additional Voltage Support, it shall procure this either through *Reliability Must-Run Contracts* or, if no other more economic sources are available by instructing a Generating Unit to move its MVar output outside its mandatory range. Only if the Generating Unit must reduce its MW output in order to comply with such an instruction will it be compensated in accordance with Section 2.5.18.

All Loads directly connected to the ISO Controlled Grid shall maintain reactive flow at grid interface points within a specified power factor band of 0.97 lag to 0.99 lead. Loads shall not be compensated for the service of maintaining the power factor at required levels within the bandwidth. A UDC interconnecting with the ISO Controlled Grid at any point other than a Scheduling Point shall be subject to the same power factor requirement.

The power factor for both the Generating Units and Loads shall be measured at the interconnection point with the ISO Controlled Grid. The ISO will develop and will be authorized to levy penalties against Participating Generators, UDCs or Loads whose

Voltage Support does not comply with the ISO's requirements. The ISO will establish voltage control standards with UDCs and the operators of other Control Areas and will enter into operational agreements providing for the coordination of actions in the event of a voltage problem occurring.

Wheeling Through and Wheeling Out transactions may also be subject to a reactive charge as developed by the ISO. If the ISO shall determine that a reactive charge should be payable at a future date, it shall, subject to FERC acceptance and approval, publish annually the Voltage Support obligations and applicable charges for Wheeling Through and Wheeling Out transactions at Scheduling Points. The obligations shall be predetermined by the ISO based on the estimated amount of the Wheeling Through and Wheeling Out transactions each year.

2.5.3.5 Black Start Capability. The ISO shall determine the amount and location of Black Start Generation it requires through contingency studies that are used as the basis of the ISO's emergency plans. The studies shall specify:

(a) the initiating disturbance;

(b) the magnitude of the Outage, including the extent of the Outage (local area, ISO Controlled Grid, or WECC), the assumed status of Generation after the initiating disturbance, the status of interconnections, the system Demand level at the time of the disturbance, the interconnection support, and assumptions regarding the availability of support from other utilities to help restore Generation and Demand;

(c) the Generator performance including a percentage of Black Start units (to be determined by the ISO) which are expected to fail to start, and

(d) expected transmission system damage.

longer-term basis pursuant to Section 2.3.5.1.3 if necessary to meet reliability criteria. The ISO Governing Board must approve all long-term Replacement Reserve contracts. The ISO shall contract for Voltage Support annually (or for such other period as the ISO may determine is economically advantageous) and on a daily or hourly basis as required to maintain System Reliability. The ISO shall contract annually (or for such other period as the ISO may determine is economically advantageous) for Black Start Generation.

2.5.6 Technical Requirements for Providing Ancillary Services.

All Generating Units, System Units, Loads and System Resources providing Ancillary Services shall comply with the technical requirements set out in Sections 2.5.6.1 to 2.5.6.4 below relating to their operating capabilities, communication capabilities and metering infrastructure. No Scheduling Coordinator shall be permitted to submit a bid to the ISO for the provision of an Ancillary Service from a Generating Unit, System Unit, Load or System Resource, or to submit a Schedule for self-provision of an Ancillary Service from that Generating Unit, System Unit, Load or System Resource, unless the Scheduling Coordinator is in possession of a current certificate issued by the ISO confirming that the Generating Unit, System Unit, Load or System Resource complies with the ISO's technical requirements for providing the Ancillary Service concerned. Scheduling Coordinators can apply for Ancillary Services certificates in accordance with the ISO's Protocols for considering and processing such applications. The ISO shall have the right to inspect Generating Units, Loads or the individual resources comprising System Units and other equipment for the purposes of the issue of a certificate and periodically thereafter to satisfy itself that its technical requirements continue to be met. If at any time the ISO's technical requirements are not being met, the ISO may withdraw the certificate for the Generating Unit, System Unit, Load or System Resource concerned.

(d) meter capability in regard to AGC response; and

(e) any other aspect of metering infrastructure required by the ISO under this ISO Tariff.

2.5.6.4 Additional Requirements for Black Start Units.

A Participating Generator who wishes to offer Black Start must ensure that the requirements set out in Appendix D to this ISO Tariff are met in relation to the Generating Units from which Black Start will be offered.

2.5.7 Methodology For Procurement of Ancillary Services Upon Commencement of ISO Operations.

2.5.7.1 [NOT USED]

2.5.7.2 Usage Charge in Ancillary Service Bid Evaluation.

As of the ISO Operations Date, the ISO will not incorporate forecast Usage Charges into its Ancillary Service bid evaluations as the means to evaluate Ancillary Service bids across Zones when Congestion is present.

2.5.7.3 Market-Based Prices.

Public utilities under the FPA must submit bids for Ancillary Services capped at FERC authorized cost-based rates unless and until FERC authorizes different pricing. Public utilities under the FPA shall seek FERC Ancillary Services rate approval on bases consistent with the ISO time-frame for contracting for each Ancillary Service (hourly rate for some Ancillary Services, annual rate or otherwise for other Ancillary Services) so that cost-based bids and market-based bids for each service shall be on comparable terms. All

other entities may use market-based rates not subject to any restrictions apart from those found in this ISO Tariff. Public utilities under the FPA which have not been approved to bid at market-based rates, will not be paid above their cost-based bid for the Ancillary Service concerned even if the relevant Market Clearing Price is higher.

2.5.7.4 Bidding and Self-Provision of Ancillary Services

The ISO will procure Ancillary Services in accordance with this ISO Tariff, and the applicable ISO Protocols.

2.5.7.4.1 Scheduling Coordinators may bid or self-provide Ancillary Services or specify Inter-Scheduling Coordinator Ancillary Service Trades from resources located within the ISO Control Area.

2.5.7.4.2 Scheduling Coordinators may bid or self-provide external imports of Spinning Reserve, Non-Spinning Reserve or Replacement Reserve from resources located outside the ISO Control Area, where technically feasible and consistent with WECC criteria; and provided that such Scheduling Coordinators have certified to the ISO their ability to deliver the service to the point of interchange with the ISO Control Area (including with respect to their ability to make changes, or cause such changes to be made, to interchange schedules during any interval of a Settlement Period at the discretion of the ISO).

2.5.7.4.3 Scheduling Coordinators may bid or self-provide external imports of Regulation from System Resources located outside the ISO Control Area, where technically feasible and consistent with WECC criteria; provided that the operator of the Control Area in which the System Resources are located has entered into an agreement with the ISO for interconnected Control Area operations; and provided that such Scheduling Coordinator and the operator of the Control Area in which the resources are located have been

certified by the ISO as to their ability to dynamically adjust interchange schedules based on control signals issued by the ISO anytime during a Settlement Period at the discretion of the ISO. Such certification shall include a demonstration of their ability to support the dynamic interchange of Regulation service based on ISO control signals received on dedicated communications links in accordance with ISO standards and procedures posted on the ISO Home Page.

2.5.7.4.4 Scheduling Coordinators may utilize transmission service under Existing Contracts to self-provide Regulation (consistent with the applicable ISO Protocols), from resources located outside the ISO Control Area, where technically feasible, consistent with WECC standards

2.5.7.4.5 Scheduling Coordinators' bidding or self-provision of Ancillary Services according to this Section 2.5.7.4 shall be consistent with the ISO Protocols.

2.5.8 The Bidding Process.

The ISO shall operate a competitive Day-Ahead and Hour-Ahead Market to procure Ancillary Services. It shall purchase Ancillary Services capacity at least cost to End-Use Customers consistent with maintaining System Reliability. Any Scheduling Coordinator representing Generating Units, System Units, Loads or external imports of System Resources may bid into the ISO's Ancillary Services market provided that it is in possession of a current certificate for the Generating Units, System Units, external imports of System Resources or Loads concerned.

2.5.9 Provision of System Information to Scheduling Coordinators.

By 6:00 p.m. two days prior to the Trading Day, the ISO shall make available to Scheduling Coordinators general system information including those items of information set forth in

Section 2.2.10. This information shall be provided at the same time as the ISO provides general system information to all Scheduling Coordinators wishing to schedule power on the ISO Controlled Grid.

2.5.10 Time Frame for Submitting And Evaluating Bids.

2.5.10.1 Day-Ahead Auction. Bids for the ISO's Day-Ahead Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve service market must be received by 10:00 am on the day prior to the Trading Day. The bids shall include information for each of the twenty-four (24) Settlement Periods of the Trading Day. Failure to provide the information within the stated time frame shall result in the bids being declared invalid by the ISO.

2.5.10.2 Hour-Ahead Auction. Bids for the ISO's Hour-Ahead Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve service market for each Settlement Period must be received at least two hours prior to the commencement of that Settlement Period. The bids shall include information for only the relevant Settlement Period. Failure to provide the information within the stated time frame shall result in the bids being declared invalid by the ISO. Scheduling Coordinators wishing to buy back in the Hour-Ahead Market Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity sold to the ISO in the Day-Ahead Market pursuant to Section 2.5.21 must do so by submitting a revised bid in the Hour-Ahead Market for the Ancillary Service and resource concerned.

2.5.11 Information To Be Submitted By Bidders.

Bids shall be submitted by Scheduling Coordinators acting on behalf of Participating Generators, and owners or operators of Loads. Bids must be in the format specified by

the ISO and include the bid information for each service described in Sections 2.5.14 to 2.5.19 and such other information as the ISO may determine it requires to evaluate bids as published from time to time in ISO Protocols. The ISO will verify and respond to submitted bid data in accordance with Appendix E and the ISO Protocols. Bidders may submit new bids on a daily basis (or hourly basis for the Hour-Ahead Market).

2.5.12 Bid Evaluation Rules.

Bid evaluation shall be based on the following principles:

(a) the ISO shall not differentiate between bidders other than through price and capability to provide the service, and the required locational mix of services;

(b) to minimize the costs to users of the ISO Controlled Grid, the ISO shall select the bidders with lowest bids for capacity which meet its technical requirements, including location and operating capability;

(c) for the Day-Ahead Market, the Day-Ahead bids shall be evaluated independently for each of the 24 Settlement Periods of the following Trading Day;

(d) for the Hour-Ahead Market, the ISO shall evaluate bids in the two hours preceding the hour of operation;

(e) the ISO will procure sufficient Ancillary Services in the Day-Ahead Market to meet its forecasted requirements, as known at the close of the Day-Ahead Market, except that the ISO may elect to procure a portion of such requirements in the Hour-Ahead Markets if the ISO first provides notice to Scheduling Coordinators of such action, including the approximate hourly megawatt amounts of each Ancillary Service that it intends to procure in the Hour-Ahead Markets.

2.5.13 Evaluation of Ancillary Services Bids.

When Scheduling Coordinators bid into the Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve markets, they may bid the same capacity into as many of these markets as desired by providing the appropriate bid information to the ISO. The ISO shall evaluate bids in the markets for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve sequentially and separately in the following order: Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve. Any capacity accepted by the ISO in one of these markets shall not be passed on to another market, except that capacity accepted in the Regulation market that represents the downward range of movement accepted by the ISO may be passed on to another market; any losing bids in one market may be passed onto another market, if the Scheduling Coordinator so indicates to the ISO. A Scheduling Coordinator may specify capacity bid into only the markets it desires. A Scheduling Coordinator shall also have the ability to specify different capacity prices and different Energy prices for the Spinning Reserve, Non-Spinning Reserve, Replacement Reserve and Regulation markets. The bid information, bid evaluation and price determination rules set forth below shall be used in the Day-Ahead, Hour-Ahead and real-time procurement of Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve.

A Scheduling Coordinator providing one or more Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve services may not change the identification of the Generating Units or Loads offered in the Day-Ahead Market, the Hour-Ahead Market or in real time for such services unless specifically approved by the ISO.

If the bid is for the provision of Regulation from an external import of a System Resource, each Scheduling Coordinator j shall submit the following information for each System Resource i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) Scheduling Point;

(d) interchange ID code;

(e) external Control Area ID;

(f) Schedule ID (NERC ID number) and complete WECC tag;

(g) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(h) the contract reference number, if applicable;

(i) maximum operating level (MW);

(j) minimum operating level (MW);

(k) ramp rate (MW/Min) $Ramp_{ijt}$;

(l) the upward and downward range of generating capacity over which System Resource i from Scheduling Coordinator j is willing to provide Regulation for Settlement Period t ($Cap_{ijt}max$ (MW)) where $Cap_{ijt}max \leq \text{Period}_{\text{minutes}} * Ramp_{ijt}$. $\text{Period}_{minutes}$ is established by the ISO, by giving Scheduling Coordinators twenty-four (24) hours advance notice, within a range from a minimum of 10 minutes to a maximum of 30 minutes. Bidders shall offer upward and downward range for Regulation service; and

Where

$TotalBid_{ijt} = CapRes_{ijt} * Cap_{ijt}$

$Requirement_t$ = Amount of upward and downward movement capacity required

Price Determination. The price payable to Scheduling Coordinators for Regulation Capacity made available for upward and downward movement in accordance with the ISO's Final Day-Ahead Schedules shall, for each Generating Unit, System Unit, and System Resource concerned, be the Zonal Market Clearing Price as follows:

$PAGC_x = MCP_{xt}$

Where:

The Zonal Market Clearing Price (MCP_{xt}) is the highest priced winning Regulation capacity bid in Zone X based on the capacity reservation bid price, i.e.

$MCP_{xt} = Max\ (CapRes_{ijt})\ in\ Zone\ x\ for\ Settlement\ Period\ t$

The ISO's auction does not compensate the Scheduling Coordinator for the minimum Energy output of Generating Units, System Units, or System Resources bidding to provide Regulation. Therefore, disposition of any minimum Energy associated with Regulation selected in the ISO's Ancillary Services markets is the responsibility of the Scheduling Coordinator selling the Regulation.

The price payable to Scheduling Coordinators for Regulation capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21 shall be the bid price of the Regulation Capacity reserved ($CapRes_{ijt}$ *($/MW)*).

$$Min \sum_{i,j} Totalbid_{ijt}$$

Subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

$$and\ Cap_{ijt} \leq Cap_{ijt}max$$

Where

$TotalBid_{ijt} = Cap_{ijt} * CapRes_{ijt}$

$Requirement_t$ = the amount of Spinning Reserve capacity required

Price Determination. The price payable to Scheduling Coordinators for Spinning Reserve Capacity made available in accordance with the ISO's Final Day-Ahead Schedules shall, for each Generating Unit or external import of a System Resource concerned be the Zonal Market Clearing Price for Spinning Reserve calculated as follows:

$Psp_{xt} = MCP_{xt}$

Where the Zonal Market Clearing Price (MCP_{xt}) for Spinning Reserve is the highest priced winning Spinning Reserve capacity bid in Zone X based on the capacity reservation bid price, i.e.:

$MCP_{xt} = Max(CapRes_{ijt})$ in Zone *x* for Settlement Period t

The ISO's auction does not compensate a Scheduling Coordinator for the minimum Energy output of Generating Units, System Units or System Resources bidding to provide Spinning Reserve. Therefore, any minimum Energy output associated with Spinning Reserve selected in the ISO's auction is the responsibility of the Scheduling Coordinator selling the Spinning Reserve.

The price payable to Scheduling Coordinators for Spinning Reserve Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21 shall be the bid price of the Spinning Reserve capacity reserved ($CapRes_{ijt}$($/MW)).

2.5.16 The Non-Spinning Reserve Auction.

Bid information. If the bid is for the provision of Non-Spinning Reserve from a Generating Unit or System Unit, each Scheduling Coordinator j must submit the following information for each Generating Unit or System Unit i for each Settlement Period t of the following Trading Day:

(a) bidder name/Identification Code;

(b) Generating Unit or System Unit identification (name and Location Code);

(c) the date for which the bid applies;

(d) maximum operating level (MW);

(e) minimum operating level (MW);

(f) ramp rate (MW/Min);

(g) the MW capability available within 10 minutes ($Cap_{ijt}max$);

(h) the bid price of the capacity reserved ($CapRes_{ijt}$($/MW));

(i) time to synchronization following notification (min);

and

(j) an indication whether the capacity reserved would be available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency.

Where

$TotalBid_{ijt} = Cap_{ijt} * CapRes_{ijt}$

$Requirement_t$ = the amount of Non-Spinning Reserve capacity required

Price Determination. The price payable to Scheduling Coordinators for Non-Spinning Reserve Capacity made available in accordance with the ISO's Final Day-Ahead Schedules shall for each Generating Unit, System Unit, Load or external import of a System Resource concerned be the Zonal Market Clearing Price for Non-Spinning Reserve calculated as follows:

$Pnonsp_{xt} = MCP_{xt}$

Where the Zonal Market Clearing Price (MCP_{xt}) for Non-Spinning Reserve is the highest priced winning Non-Spinning Reserve bid in Zone X based on the capacity reservation bid price, i.e.:

$MCP_{xt} = Max(CapRes_{ijt})$ in Zone *x* for Settlement Period t.

The price payable to Scheduling Coordinators for Non-Spinning Reserve Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21 shall be the bid price of the Non-Spinning Capacity reserved ($CapRes_{ijt}$($/MW$)).

2.5.17 The Replacement Reserve Auction.

Bid Information. If the bid is for the provision of Replacement Reserve from a Generating Unit or System Unit each Scheduling Coordinator j must submit the following information

System Resource, be the Zonal Market Clearing Price for Replacement Reserve calculated as follows:

$PRepRes_{xt} = MCP_{xt}$

Where the Zonal Market Clearing Price (MCP_{xt}) for Replacement Reserve is the highest priced winning Replacement Reserve bid in Zone X based on the capacity reservation bid price, i.e.:

$MCP_{xt} = Max(CapRes_{ijt})$ in Zone *x* for Settlement Period t.

The price payable to Scheduling Coordinators for Replacement Reserve Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services schedules issued in accordance with Section 2.5.21 shall be the bid price of the Replacement Reserve capacity reserved ($CapRes_{ijt}(\$/MW)$).

2.5.18 Voltage Support.

As of the ISO Operations Date, the ISO will contract for Voltage Support service with the owners of Reliability Must-Run Units. Payments for public utilities under the FPA shall be capped at the FERC authorized cost-based rates unless and until FERC authorizes different pricing. The ISO shall pay owners of Reliability Must-Run Units for long-term Voltage Support through their Scheduling Coordinators.

In addition, any Participating Generator who is producing Energy shall, upon the ISO's specific request, provide reactive energy output outside the Participating Generator's Voltage Support obligation defined in Section 2.5.3.4.

The ISO shall select Participating Generator's Generating Units which have been certified for Voltage Support to provide this additional Voltage Support. Subject to any

locational requirements, the ISO shall select the least costly Generating Units from a computerized merit order stack to back down to produce additional Voltage Support in each location where Voltage Support is needed.

The ISO shall pay to the Scheduling Coordinator for that Participating Generator the opportunity cost of reducing Energy output to enable reactive energy production. This opportunity cost shall be:

Max{0, Zonal Settlement Interval Ex Post Price - Generating Unit bid price } x reduction in Energy output (MW).

If necessary, the ISO shall develop a regulatory cost-based determination of marginal operating cost to be used in place of the Generating Unit bid price.

2.5.19 Black Start Capability and Energy Output.

As of the ISO Operations Date, the ISO will contract for Black Start capability and Energy with owners of Reliability Must-Run Units and Black Start Generators. Public utilities under the FPA will be paid rates capped at the FERC authorized cost base rates unless and until FERC authorizes different pricing. The ISO shall pay owners of Reliability Must-Run Units for Black Start Energy output through their Scheduling Coordinators. The ISO shall pay Black Start Generators for Black Start Energy output directly.

2.5.20 Obligations for and Self-Provision of Ancillary Services.

2.5.20.1 Ancillary Service Obligations. Each Scheduling Coordinator shall be assigned a share of the total Regulation, Spinning Reserve, Non-Spinning and Replacement Reserve requirements by the ISO. Any references in this Tariff to the Ancillary Service "Regulation" shall be read as referring to "Regulation Up" or "Regulation Down". The

share assigned to each Scheduling Coordinator is described in Section 2.5.20 and in Section 2.5.28 as that Scheduling Coordinator's obligation. Each Scheduling Coordinator's Regulation obligation in each Zone shall be pro rata based upon the same proportion as the Scheduling Coordinator's metered hourly Demand (excluding exports) bears to the total metered Demand (excluding exports) served in each hour in that Zone. Each Scheduling Coordinator's Operating Reserve obligation in each Zone shall be pro rata based upon the same proportion as the ratio of the product of its percentage obligation based on metered output and the sum of its metered Demand and firm exports bears to the total of such products for all Scheduling Coordinators in the Zone. The Scheduling Coordinator's percentage obligation based on metered output shall be calculated as the sum of 5% of its real-time Demand (except the Demand covered by firm purchases from outside the ISO Control Area) met by Generation from hydroelectric resources plus 7% of its Demand (except the Demand covered by firm purchases from outside the ISO Control Area) met by Generation from non-hydroelectric resources in that Zone, plus 100% of any Interruptible Imports and on-demand obligations which it schedules. Each Scheduling Coordinator's Replacement Reserve obligation in each Zone is calculated as described in Section 2.5.28.4. Scheduling Coordinator obligations for each Ancillary Service will be calculated based on the requirement for each Ancillary Service as the ISO determines prior to the adjustment set forth in Section 2.5.3.6.

2.5.20.2 Right to Self-Provide.

Each Scheduling Coordinator may choose to self-provide all, or a portion, of its Regulation, Operating Reserve, and Replacement Reserve obligation in each Zone. The ISO shall schedule self-provided Ancillary Services, Day-Ahead and Hour-Ahead, and Dispatch self-provided Ancillary Services in real time. To the extent that a Scheduling Coordinator self-provides, the ISO shall correspondingly reduce the quantity of the Ancillary Services

concerned, which it procures as described in Sections 2.5.14 to 2.5.17. In accordance with Section 2.5.22.11 and Section 2.5.26.2, if a Scheduling Coordinator uses capacity scheduled to self-provide Spinning Reserve, Non-Spinning Reserve, or Replacement Reserve to supply Uninstructed Imbalance Energy to the ISO from a Generating Unit, Curtailable Demand, or System Resource under circumstances that would cause the elimination of payments to the Scheduling Coordinator under Section 2.5.26.2 if the capacity had been bid and was selected by the ISO to supply the Ancillary Service, the Scheduling Coordinator shall pay to the ISO the amount of the payment that would be eliminated under that section. Scheduling Coordinators may trade Ancillary Services obligations so that any Scheduling Coordinator may reduce its Ancillary Services obligation through purchase of Ancillary Services capacity from another Scheduling Coordinator, or self-provide in excess of its obligation to sell Ancillary Services to another Scheduling Coordinator, subject to the limits specified under Section 2.5.20.5.2. If a Scheduling Coordinator's Day-Ahead self-provided Ancillary Service Schedule is decreased in the Hour-Ahead Market, such decrease shall be deemed to be replaced at the Market Clearing Price in the Hour-Ahead Market, pursuant to Section 2.5.21.

2.5.20.3 [Not Used]

2.5.20.4 Services Which May Be Self-Provided. The ISO shall permit Scheduling Coordinators to self-provide the following Ancillary Services:

(a) Regulation;

(b) Spinning Reserve;

(c) Non-Spinning Reserve; and

(d) Replacement Reserve.

The ISO may from time to time add other Ancillary Services to this list as it considers appropriate.

2.5.20.5 Time Frame for Informing ISO of Self-Provision.

2.5.20.5.1 Day-Ahead Schedule. At the Day-Ahead scheduling process, Scheduling Coordinators shall be required to submit information on self-provided Ancillary Services within the time frame stated in Section 2.5.10.1. Failure to submit the required information within the stated time frame for any hour shall lead to the self-provision for that hour being declared invalid by the ISO, and under such circumstances the ISO shall purchase sufficient Ancillary Services to meet the Scheduling Coordinator's requirements to match its Day-Ahead Schedule.

2.5.20.5.2 Hour-Ahead Schedule. Increases in each Scheduling Coordinator's self-provided Ancillary Service between the Day-Ahead and Hour-Ahead Markets shall be limited to the estimated incremental Ancillary Service requirement associated with the increase between the Day-Ahead and Hour-Ahead Markets in that Scheduling Coordinator's scheduled Zonal Demand. Notwithstanding this limit on increases in Hour-Ahead self-provision, a Scheduling Coordinator may buy or sell Ancillary Services through Inter-Scheduling Coordinator Ancillary Service Trades in the Hour-Ahead Market. In the Hour-Ahead scheduling process, Scheduling Coordinators shall be required to submit information on self-provided Ancillary Services within the time frame stated in Section 2.5.10.2. Failure to submit the required adjusted information within the stated time frame shall lead to the self-provision being declared invalid by the ISO, and under such circumstances the ISO shall purchase the additional Ancillary Services necessary to meet the requirements for that Scheduling Coordinator.

2.5.20.6 Information To Be Submitted By Scheduling Coordinators For Each Service.

Scheduling Coordinators electing to self-provide Ancillary Services shall submit the information for each self-provided Ancillary Service as described in Sections 2.5.14 to 2.5.17, excluding the capacity price information, but including the name of the trading Scheduling Coordinator in the case of Inter-Scheduling Coordinator Ancillary Service Trades.

2.5.20.7 Acceptance of Self-Provided Ancillary Service Schedules. The ISO will refuse to accept self-provided Ancillary Service Schedules only to the extent that they fail to meet requirements contained in this ISO Tariff. In particular, self-provided Ancillary Service Schedules must satisfy the following conditions:

(a) the Scheduling Coordinator has a current certificate of technical eligibility for the Generating Units, System Units, Loads or System Resources selected for the Ancillary Services in question;

(b) to the extent not provided under (a), the Generating Units, System Units, Loads and System Resources have the instrumentation, communication and metering equipment necessary to permit the ISO to dispatch the offered Ancillary Services and verify that the services have been provided;

(c) the scheduling information provided by the Scheduling Coordinator is deemed to be valid in accordance with Appendix E and the ISO Protocols; and

(d) the Generating Units, System Units, Loads or System Resources meet the ISO's locational requirements for the Ancillary Services.

2.5.21 Scheduling of Units to Provide Ancillary Services.

The ISO shall prepare supplier schedules for Ancillary Services (both self-provided and purchased by the ISO) for the Day-Ahead and the Hour-Ahead Markets. The ISO shall

notify each Scheduling Coordinator no later than 1:00 p.m. of the day prior to the Trading Day of their Ancillary Services schedules for the Day-Ahead and no later than one hour prior to the operating hour of their Ancillary Services schedules for the Hour-Ahead. The ISO Protocols set forth the information, which will be included in these schedules. Where long-term contracts are involved, the information may be treated as standing information for the duration of the contract.

If, at any time after the issuance of Final Day-Ahead Schedules for the Trading Day and before the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day, the ISO determines that it requires Ancillary Services in addition to those included in the Final Day-Ahead Schedule (in the appropriate Zone if procuring zonally), the ISO may procure such additional Ancillary Services by providing Scheduling Coordinators with amended supplier schedules for the Day-Ahead Markets that include Ancillary Services for which previously submitted (but not selected) bids remain available and have not previously been withdrawn. The ISO shall select such Ancillary Services in price merit order (and in the relevant Zone if the ISO is procuring Ancillary Services on a Zonal basis). Such amended supplier schedules shall be provided to the Scheduling Coordinators no later than the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day.

Once the ISO has given Scheduling Coordinators notice of the Day-Ahead and Hour-Ahead Schedules, these schedules represent binding commitments made in the markets between the ISO and the Scheduling Coordinators concerned, subject to any amendments issued as described above. Any minimum energy input and output associated with Regulation and Spinning Reserve services shall be the responsibility of the Scheduling Coordinator, as the ISO's auction does not compensate the Scheduling Coordinator for the minimum energy output of Generating Units bidding to provide these

services. Accordingly the Scheduling Coordinators shall adjust their schedules to accommodate the minimum outputs required by the Generating Units included on the Schedules.

Notwithstanding the foregoing, a Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace that capacity in whole or in part from the ISO if the scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or if the Ancillary Service associated with a Generating Unit, Curtailable Demand, or System Resource successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduling Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replaced Ancillary Service shall be the Market Clearing Price in the Hour-Ahead Market for the Ancillary Service for the Settlement Period concerned for the Zone in which the Generating Units or other resources are located. The ISO will purchase the Ancillary Service concerned from another Scheduling Coordinator in the Hour-Ahead Market in accordance with the provisions of the ISO Tariff.

2.5.22 Rules For Real-Time Dispatch of Imbalance Energy Resources.

2.5.22.1 Overview. During real time, the ISO shall dispatch Generating Units, Loads and System Resources to procure Imbalance Energy. In addition, the ISO may also need to purchase additional Ancillary Services if the services arranged in advance are used to provide Imbalance Energy, and such depletion needs to be recovered to meet reliability contingency requirements.

2.5.22.2 General Principles. The ISO shall base real-time Dispatch of Generating Units, System Units, Loads and System Resources on the following principles:

(a) the ISO shall dispatch Generating Units, System Units, and System Resources providing Regulation service to meet NERC and WECC Area Control Error (ACE) performance requirements;

(b) the ISO shall determine whether the Regulation Generating Units, System Units, and System Resources are operating at a point away from their preferred operating point and project the Imbalance Energy requirements based on the forecasted Demand for the next Dispatch Interval. The ISO shall then Dispatch Generating Units, System Units, and System Resources available (either providing Spinning Reserve, Non-Spinning Reserve, Replacement Reserve or offering Supplemental Energy) to meet the projected Imbalance Energy requirements for the next Dispatch Interval and return the Regulation Generating Units, System Units, and System Resources to their preferred operating points to restore their full regulating margin;

(c) the ISO shall economically Dispatch Generating Units, System Units, Loads and System Resources only to meet its Imbalance Energy requirements and eliminate any Price Overlap between Energy Bids subject to resource and transmission system Constraints;

(d) subject to Section 2.5.22.3 and its subparts, the ISO shall select the Generating Units, System Units, Loads and System Resources to be dispatched to meet its Imbalance Energy requirements and eliminate any Price Overlap based on a constrained optimization method to minimize the overall cost of Imbalance Energy subject to resource and transmission system Constraints;

(e) subject to Section 2.5.22.3 and its subparts, the ISO shall not discriminate between Generating Units, System Units, Loads and System Resources other than based on

price, and the effectiveness (e.g., location and ramp rate) of the resource concerned to respond to the fluctuation in Demand or Generation;

(f) Generating Units, System Units, Loads and System Resources shall be dispatched during the operating hour only until the next variation in Demand or the end of the operating hour, whichever is sooner. In dispatching such resources, the ISO makes no further commitment as to the duration of their operation, nor the level of their output or Demand, except to the extent that a Dispatch instruction causes Energy to be delivered in a different Dispatch Interval.

2.5.22.3 Ancillary Services Dispatch. The ISO may Dispatch Generating Units, Loads, System Units and System Resources contracted to provide Ancillary Services (either procured through the ISO's competitive market, or self-provided by Scheduling Coordinators) to supply Imbalance Energy. During normal operating conditions, the ISO shall Dispatch the following resources to supply Imbalance Energy: (i) those Generating Units, Loads, System Units and System Resources having offered Supplemental Energy bids, (ii) those Generating Units, Loads, System Units and System Resources contracted to provide Replacement Reserve and (iii) those Generating Units, Loads, System Units and System Resources that have contracted to provide Spinning and Non-Spinning Reserve, except for those resources that have indicated that the capacity reserved would be available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency. In the event of an unplanned Outage, a Contingency or a threatened or actual System Emergency, the ISO may also Dispatch all other Generating Units, Loads, System Units and System Resources contracted to provide Spinning Reserve or Non-Spinning Reserve to supply Imbalance Energy. If a Generating Unit, Load, System Unit or System Resource, which is supplying Operating Reserve, is Dispatched to provide Imbalance Energy, the ISO shall

replace the Operating Reserve from the same or another resource within the time frame specified in the WECC guidelines.

2.5.22.3.1 Dispatch of Competitively Procured and Self-Provided Ancillary Services. Generating Units and Loads selected in the ISO competitive auction or self-provided shall be Dispatched based on their Energy Bids as described in Dispatch Protocol Section 8.6.2, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 2.5.22.3.

2.5.22.3.2 Dispatch of Self-Provided Ancillary Services. Where a Scheduling Coordinator has chosen to self-provide the whole of the additional Operating Reserve required to cover any Interruptible Imports which it has scheduled and has identified specific Generating Units, Loads, System Units or System Resources as the providers of the additional Operating Reserve concerned, the ISO shall Dispatch only the designated Generating Units, Loads, System Units or System Resources in the event of the ISO being notified that the Interruptible Import is being curtailed. For all other Ancillary Services

which are being self-provided the Energy Bid shall be used to determine the Dispatch, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 2.5.22.3.

2.5.22.4 Supplemental Energy Bids. In addition to the Generating Units, Loads and System Resources which have been scheduled to provide Ancillary Services in the Day-Ahead and Hour-Ahead Markets, the ISO may Dispatch Generating Units, Loads or System Resources for which Scheduling Coordinators have submitted Supplemental Energy bids.

2.5.22.4.1 Timing of Supplemental Energy Bids.

Supplemental Energy bids must be submitted to the ISO no later than sixty (60) minutes prior to the operating hour. Bids may also be submitted at any time after the Day-Ahead Market closes. These Supplemental Energy bids cannot be withdrawn after sixty (60) minutes prior to the Settlement Period.

2.5.22.4.2 Form of Supplemental Energy Bid Information.

Supplemental Energy bids must include the information specified in Schedules and Bids Protocol Section 6.1.

2.5.22.6 Real-Time Dispatch. The ISO shall economically Dispatch each Generating Unit, Curtailable Demand, System Unit or System Resource that is effective to meet Imbalance Energy requirements and eliminate any Price Overlap in real time, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 2.5.22.3. The ISO shall determine that additional output is needed if the current output levels of the Regulation Generating Units, System Units, and System Resources deviate from their preferred operating points by more than a specified threshold (to be determined by the ISO), or to meet the projected Imbalance Energy requirements for the next Dispatch Interval. The ISO shall employ a multi-interval constrained optimization methodology (RTD Software) to calculate an optimal dispatch for each Dispatch Interval within a time horizon that shall extend to the end of the next hour. The ISO shall Dispatch resources that have submitted Energy Bids over the time horizon to meet forecasted Imbalance Energy requirements minimizing the Imbalance Energy procurement cost over the entire time horizon, subject to resource and transmission system constraints. However, Dispatch Instructions shall be issued for the next Dispatch Interval only. The ISO also shall instruct resources to start up or shut down over the time horizon based on their submitted and validated Start-Up Fuel Costs, Minimum Load Costs and Energy Bids. These resources shall receive binding start-up or shut-down pre-dispatch instructions as required by their startup time. The ISO shall only start resources that can start within the time horizon. The ISO may shut down resources that do not need to be on-line if constraints within the time horizon permit. However, resources providing Regulation or Spinning Reserve shall not be shut down. On-line resources providing Non-Spinning or Replacement Reserve shall also not be eligible for shutdown, unless their minimum down time does not exceed 10 minutes.

2.5.22.6.1 Resource Constraints.

The RTD Software shall enforce the following resource physical constraints:

g) Hourly Pre-Dispatch. If Dispatched, each System Resource flagged for Hourly Pre-Dispatch in the next hour shall be Dispatched to operate at a constant level over the entire hour. The RTD Software shall perform the Hourly Pre-Dispatch for each hour once prior to the operating hour. Hourly Pre-Dispatched System Resources shall be Pre-Dispatched in merit order, but shall be price-takers, *i.e.*, shall not set the price. The Hourly Pre-Dispatch shall not subsequently be revised by the RTD Software.

2.5.22.6.2 Transmission System Constraints.

RTD shall use a Zonal DC network model where all nodes within a Zone would be collapsed into a single equivalent "Zonal bus." The constraints using the Zonal network model shall be the following:

a) Power balance constraint in each Zone. The system Imbalance Energy requirement shall be calculated on a Zonal basis. The power balance constraints shall dictate an optimal Dispatch that would eliminate the Imbalance Energy requirement in all Zones, subject to (b) below.

b) Inter-Zonal Interface constraints. These constraints shall limit the net active power flow on Inter-Zonal Interfaces at or below their transfer limits. For Inter-Zonal Interfaces between the ISO Control Area and another Control Area, inter-Zonal transfer capacity shall be reserved for awarded Ancillary Services from System Resources not already Dispatched.

2.5.22.6.3 Inter-hour Dispatch of Resources Without Real-Time Energy Bids.

Real-time Dispatch Instructions shall be issued for each Dispatch Interval as needed to prescribe the ramp between a resource's Final Hour-Ahead Schedule in one hour to its Final Hour-Ahead Schedule in the immediately succeeding operating hour. Such Dispatch Instructions shall be based on the lesser of: 1) the applicable operational ramp rate as provided for in SBP Section 6.5 and 2) the ramp rate associated with the Standard Ramp. The Dispatch

Instructions for ramping of Generating Units without real-time Energy Bids in both operating hours shall begin 10 minutes prior to the start of each operating hour and shall end no sooner than 10 minutes after and no later than 50 minutes after the start of each operating hour. Energy resulting from the Standard Ramp shall be deemed Standard Ramping Energy and will be settled in accordance with SABP Appendix D-1 Section 2.1.2. Energy resulting from any ramp extending beyond the Standard Ramp will be deemed Ramping Energy Deviation and will be settled in accordance with SABP Appendix D-1 Section 2.1.2.

2.5.22.6.4 Inter-hour Dispatch of Resources With Real-Time Energy Bids.

Real-time Dispatch Instructions associated with the ramp between a resource's Final Hour-Ahead Schedule in one hour to its Final Hour-Ahead Schedule in the immediately succeeding operating hour shall be determined optimally by the RTD Software if the ISO has bids for either or both relevant operating hours. For any operating hour(s) for which bids have been submitted Dispatch Instructions will be optimized such that the Dispatch Operating Point is within the bid range(s). For any operating hour without submitted bids Dispatch Instructions will be optimized such that the Dispatch Operating Point conforms to the schedule within the operating hour. Energy resulting from the Standard Ramp shall be deemed Standard Ramping Energy and will be settled in accordance with SABP Appendix D Section 2.1.2. Energy resulting from any ramp extending beyond the Standard Ramp will be deemed Ramping Energy Deviation and will be settled in accordance with SABP Appendix D Section 2.1.2. Energy delivered or consumed as a result of ISO Dispatch of a resource's Energy Bid in one operating hour to a Dispatch Operating Point such that the resource cannot return to its successive operating hour Final Hour-Ahead Schedule by the beginning of the next operating hour is Residual Energy and shall be settled as Instructed Imbalance Energy as provided for in SABP Appendix D Section 2.1.2 and also may be eligible for recovery of its applicable Energy Bid costs in accordance with Section 11.2.4.1.1.1. Similarly, Energy delivered or consumed as a result of ISO Dispatch of a

wishes to Dispatch. The recipient Scheduling Coordinator shall ensure that the Dispatch Instruction is communicated immediately to the operator of the Generating Unit, System Unit, external import of System Resources or Load concerned. The ISO may, with the prior permission of the Scheduling Coordinator concerned, communicate with and give Dispatch Instructions to the operators of Generating Units, System Units, external imports of System Resources and Loads directly without having to communicate through their appointed Scheduling Coordinator. The recipient of a Dispatch Instruction shall confirm the Dispatch in accordance with DP 4.4. The ISO shall record the communications between the ISO and Scheduling Coordinators relating to Dispatch Instructions in a manner that permits auditing of the Dispatch Instructions, and of the response of Generating Units, System Units, external imports of System Resources and Loads to Dispatch Instructions.

The ISO Protocols govern the content, issue, receipt, confirmation and recording of Dispatch Instructions.

2.5.22.11 Failure to Conform to Dispatch Instructions. All Scheduling Coordinators, Participating Generators, owners or operators of Curtailable Demands and operators of System Resources providing Ancillary Services (whether self-provided or procured by the ISO) or whose Supplemental Energy bids have been accepted by the ISO shall be obligated to respond or to secure response to the ISO's Dispatch Instructions in accordance with their terms, and to be available and capable of doing so, for the full duration of the Settlement Period. Dispatch Instructions will be deemed delive red and associated Energy will be settled as Instructed Imbalance Energy in accordance with Section 11.2.4.1.1. If a Generating Unit, Curtailable Demand or System Resource is unavailable or incapable of responding to a Dispatch Instruction, or fails to respond to a Dispatch Instruction in accordance with its terms, the Generating Unit, Curtailable Demand or System Resource:

(c) the Scheduling Coordinator for the Participating Generator, owner or operator of the Curtailable Demand or System Resource concerned shall have Uninstructed Imbalance Energy due to the difference between the Generating Unit's, Curtailable Demand's or System Resource's instructed and actual output (or Demand). The Uninstructed Imbalance Energy shall be subject to the settlement for Uninstructed Imbalance Energy in accordance with Section 11.2.4.1 and the Uninstructed Deviation Penalty in accordance with Section 11.2.4.1.2. This applies whether the Ancillary Services concerned are contracted or self-provided.

The ISO will develop additional mechanisms to deter Generating Units, Curtailable Demand and System Resources from failing to perform according to Dispatch instructions, for example reduction in payments to Scheduling Coordinators, or suspension of the Scheduling Coordinator's Ancillary Services certificate for the Generating Unit, Curtailable Demand or System Resource concerned.

2.5.23 Pricing Imbalance Energy.

2.5.23.1 General Principles. Instructed and Uninstructed Imbalance Energy shall be paid or charged the applicable Resource-Specific Settlement Interval Ex Post Price or the Zonal Settlement Interval Ex Post Price. These prices are determined using the Dispatch Interval Ex Post Prices. The Dispatch Interval Ex Post Prices shall be based on the bid of the marginal Generating Units, System Units, and Curtailable Demand dispatched by the ISO to increase or reduce Demand or Energy output in each Dispatch Interval as provided in Section 2.5.23.2.1.

The marginal bid is

the highest bid that is accepted by the ISO's RTD Software for increased energy Supply or the lowest bid that is accepted by the ISO's RTD Software for reduced energy Supply. In the event the lowest price decremental bid accepted by the ISO is greater and not equal to the highest priced incremental bid accepted, then the Dispatch Interval Ex-Post Price shall be equal to the highest incremental bid accepted when there is a non-negative Imbalance Energy system requirement and equal to the lowest accepted decremental bid when there is a negative Imbalance Energy requirement.

When an Inter-Zonal Interface is operated at the capacity of the interface (whether due to scheduled uses of the interface, or decreases in the capacity of the interface), the marginal incremental or decremental bid prices in some Zones may differ from one another. In such cases, the ISO will determine separate Ex Post Prices for the Zones.

The ISO will respond to the Dispatch instructions issued by the RTD Software to the extent practical in the time available and acting in accordance with Good Utility Practice. The ISO will record the reasons for any variation from the Dispatch instructions issued by the RTD Software.

2.5.23.2 Determining Ex Post Prices.

2.5.23.2.1 Dispatch Interval Ex Post Prices.

2.5.23.2.1.1 Computation. For each Dispatch Interval, the ISO will compute updated supply and demand curves, using the Generating Units, System Units, and Curtailable Demand Dispatched according to the ISO's RTD Software during that time period to meet Imbalance Energy requirements and to eliminate any Price Overlap. The Dispatch Interval Ex Post Price is equal to the bid price of the marginal resource accepted by the ISO for Dispatch, subject to any limitation applicable under Section 2.5.23.2.1. In the event of Inter-Zonal Congestion, the ISO

will determine separate Dispatch Interval Ex Post Prices for each Zone or groups of Zones on either side of the Congested interface.

2.5.23.2.1.2 Eligibility. A resource constrained at an upper or lower operating limit, a boundary of a Forbidden Operating Region or dispatched for the maximum Energy deliverable based on its maximum applicable ramp rate cannot be marginal (*i.e.*, it cannot move in a particular direction) and thus is not eligible to set the Dispatch Interval Ex Post Price. System Resources are not eligible to set the Dispatch Interval Ex Post Price. A resource dispatched at its lower operating limit, if otherwise eligible, will be eligible to set the Dispatch Interval Ex Post Price if any portion of its Energy is necessary to serve Demand.

2.5.23.2.2 Hourly Ex Post Price. The Hourly Ex Post Price in a Settlement Period in each Zone will equal the absolute-value Energy-weighted average of the Dispatch Interval Ex Post Prices in each Zone, where the weights are the system total Instructed Imbalance Energy, except Regulation Energy, for the Dispatch Interval.

If the ISO declares a System Emergency, e.g. during times of supply scarcity, and involuntary Load Shedding occurs during the real-time Dispatch, the ISO shall set the Hourly Ex Post Price at the Administrative Price.

2.5.23.2.3 Price for Uninstructed Deviations for Participating Intermittent Resources. Deviations associated with each Participating Intermittent Resource in a Scheduling Coordinator's Zonal portfolio shall be settled as provided in Section 11.2.4.5.1 at the monthly weighted average Dispatch Interval Ex Post Price, where the weights are the quantities of Instructed Imbalance Energy associated with each Dispatch Interval Ex Post Price.

2.5.23.3 [Not Used]

2.5.23.3.1 [Not Used]

2.5.23.3.1.1 [Not Used]

2.5.23.3.3 Requirement of Must-Offer Generators to File Heat Rate and Emissions Rate Data

Must-Offer Generators, as defined in Section 5.11 of this ISO Tariff, that own or control gas-fired Generating Units must file with the ISO and the FERC, on a confidential basis, the heat rates and emissions rates for each gas-fired Generating Unit that they own or control. Heat rate and emissions rate data shall be provided in the format specified by the ISO as posted on the ISO Home Page. Heat rate data provided to comply with this requirement shall not include start-up or minimum load fuel costs. Must-Offer Generators must also file periodic updates of this data upon the direction of either FERC or the ISO. The ISO will treat the information provided to the ISO in accordance with this Section 2.5.23.3.3 as confidential and will apply the procedures in Section 20.3.4 of this ISO Tariff with regard to requests for disclosure of such information.

2.5.23.3.4 Calculation of the Proxy Price

The ISO shall calculate each day separate Proxy Prices for each gas-fired Generating Unit owned or controlled by a Must-Offer Generator by applying the filed heat rates for those Generating Units to a daily proxy figure for natural gas costs with an additional $6/MWh allowed for operations and maintenance expenses. The proxy figures for natural gas costs shall be based on the most recent data available and shall be posted on the ISO Home Page by 8:00 AM on the day prior to which the figures will be used for calculation of the Proxy Price.

2.5.23.3.5 [Not Used]

ISO may credit or debit, as appropriate, the account of a Scheduling Coordinator for any over- or under-assessment of Emissions Cost Charges that the ISO determines occurred due to the error, omission, or miscalculation by the ISO or the Scheduling Coordinator.

2.5.23.3.6.6 Submission of Emissions Cost Invoices

Scheduling Coordinators for Must-Offer Generators that incur Emissions Costs as a direct result of an ISO Dispatch instruction may submit to the ISO an invoice in the form specified on the ISO Home Page (the "Emissions Cost Invoice") for the recovery of such Emissions Costs. Emissions Cost Invoices shall not include any Emissions Costs specified in an RMR Contract for a unit owned or controlled by a Must-Offer Generator. All Emissions Cost Invoices must include a copy of all final invoice statements from air quality districts demonstrating the Emissions Costs incurred by the applicable Generating Unit, and such other information as the ISO may reasonably require to verify the Emissions Costs incurred as a direct result of an ISO Dispatch instruction.

2.5.23.3.6.7 Payment of Emissions Cost Invoices

The ISO shall pay Scheduling Coordinators for all Emissions Costs submitted in an Emissions Cost Invoice and demonstrated to be a direct result of an ISO Dispatch instruction. If the Emissions Costs indicated in the applicable air quality districts' final invoice statements include emissions produced by operation not resulting from ISO Dispatch instructions, the ISO shall pay an amount equal to Emissions Costs multiplied by the ratio of the MWh associated with ISO Dispatch instruction to the total MWh associated with such Emissions Costs. The ISO shall pay Emissions Cost Invoices each month in accordance with the ISO Payments Calendar from the funds available in the Emissions Cost Trust Account. To the extent there are insufficient funds available in Emissions Cost Trust Account in any month to pay all Emissions Costs submitted in an Emissions Cost Invoice and demonstrated to be a direct result of an ISO Dispatch instruction, the ISO shall make pro rata payment of such Emissions Costs and shall adjust the rate at which

2.5.23.3.8.2 [Not Used]

2.5.24 Verification of Performance of Ancillary Services.

Availability of both contracted and self-provided Ancillary Services shall be verified by the ISO by unannounced testing of Generating Units, Loads and System Resources, by auditing of response to ISO Dispatch instructions, and by analysis of the appropriate Meter Data, or interchange schedules. Participating Generators, owners or operators of Loads, operators of System Units or System Resources and Scheduling Coordinators shall notify the ISO immediately whenever they become aware that an Ancillary Service is not available in any way.

All Participating Generators, owners or operators of Loads and operators of System Units or System Resources shall check, monitor and/or test their system and related equipment routinely to assure availability of the committed Ancillary Services. These requirements apply whether the Ancillary Services are contracted or self-provided. For a duration specified by the ISO, the ISO may suspend the technical eligibility certificate of a Scheduling Coordinator for a Generating Unit, System Unit, Load or System Resource, which repeatedly fails to perform. The ISO shall develop measures to discourage repeated non-performance on the part of both bidders and self-providers.

2.5.25 Periodic Testing of Units.

The ISO may test Generating Units, System Units, Loads and System Resources in the manner described herein. The frequency of testing shall be within such timeframes as are reasonable under all the circumstances. Scheduling Coordinators shall manage the resulting Energy output if notification of testing permits the Energy to be scheduled. If a Generating Unit, System Unit, Load, or System Resource fails to meet requirements in a

test under this section, the ISO shall notify the relevant Participating Generator, owner or operator of Loads, System Units or System Resources, or Scheduling Coordinator of such failure as soon as reasonably practicable after the completion of the test. Failure to meet requirements shall lead to the penalties described in Section 2.5.26.

2.5.25.1 Regulation. The ISO shall continuously monitor the response of a Generating Unit, System Unit, or System Resource to the ISO's Regulation instructions in order to determine compliance with Dispatch instructions.

2.5.25.2 Spinning Reserve. The ISO shall test the Spinning Reserve capability of a Generating Unit, System Unit or System Resource by issuing unannounced Dispatch instructions requiring the Generating Unit, System Unit or System Resource to ramp up to its ten minute capability. The ISO shall measure the response of the Generating Unit, System Unit or System Resource to determine compliance with requirements. The Scheduling Coordinator for the Generating Unit, System Unit or System Resource shall be paid the Energy Bid price of the Generating Unit or System Unit for the output under the Spinning Reserve test.

2.5.25.3 Non-Spinning Reserve. The ISO may test the Non-Spinning Reserve capability of a Generating Unit, Load, System Unit or System Resource by issuing unannounced Dispatch instructions requiring the Generating Unit, Load, System Unit or System Resource to come on line and ramp up or to reduce Demand to its ten minute capability. The ISO shall measure the response of the Generating Unit, System Unit, System Resource or Load to determine compliance with requirements. The Scheduling Coordinator for the Generating Unit, System Unit, Load or System Resource shall be paid the Energy (or Demand reduction) Bid price of the Generating Unit, System Unit, Load or System Resource for its output or reduction, under the Non-Spinning Reserve test.

provide the Service, unless appropriate documentation (i.e., daily test records) confirming the availability of that service during the committed period(s) is presented to the ISO. The "committed period" is defined as the total of all the hours/days the Generating Unit, Curtailable Demand, System Unit or System Resource was scheduled by the ISO to provide the Ancillary Service beginning from: (i) the last successful availability test; or (ii) the last time the Generating Unit, Curtailable Demand, System Unit or System Resource actually provided Energy or reduced Demand as part of the Ancillary Service; whichever results in a shorter committed period. The Scheduling Coordinator for a Generating Unit, Curtailable Demand, System Unit or System Resource that fails an availability test shall not be entitled to payment for the Ancillary Service concerned for the committed period and adjustments to reflect this shall be made in the calculation of payments to the Scheduling Coordinator, provided that any such penalty shall be reduced to reflect any adjustment made over the duration of the committed period under Section 2.5.26.2 or 2.5.26.3.

System Units engaged in self-provision of Ancillary Services, or providing Ancillary Services to the ISO are subject to the same testing, compensation, and penalties as are applied to individual Generating Units engaged in self-provision or provision of Ancillary Services. To perform testing, the ISO will bias the MSS's MSRE to test the responsiveness of the System Unit.

If payments for capacity for a particular Ancillary Service in a particular Settlement Period would be rescinded under more than one provision of this Section 2.5.26, the total amount to be rescinded for a particular Ancillary Service in a particular Settlement Period shall not exceed the total payment due in that Settlement Period.

2.5.26.2.3 The ISO shall calculate the real-time ability of each Generating Unit and System Unit to deliver Energy from Ancillary Services capacity awarded or self-provided for each Settlement Interval based on its operational ramp rate as described in SBP Section 6.5, maximum operating capability, and actual telemetered output. If the Generating Unit or System Unit cannot deliver the full amount of Energy from the awarded or self-provided Spinning, Non-Spinning or Replacement Reserve for a Settlement Interval then Ancillary Services capacity payments for the amount of Energy that cannot be delivered for the particular Settlement Interval shall be rescinded.

2.5.26.2.4 This Section 2.5.26.2.4 shall not apply to the capacity payment for any particular Ancillary Service if the Zonal Market Clearing Price determined in accordance with Sections 2.5.15, 2.5.16 or 2.5.17 is less than or equal to zero. For those Ancillary Services for which such Zonal Market Clearing Prices are greater than zero, the payment for Ancillary Service capacity otherwise payable under Section 2.5.27.2, 2.5.27.3, and/or 2.5.27.4 shall be reduced by one sixth of the product of the applicable prices and the amount of Ancillary Service capacity from which the Generating Unit, Curtailable Demand, System Unit or System Resource has supplied Uninstructed Imbalance Energy in a Settlement Interval. If a Scheduling Coordinator schedules Ancillary Services through both the Day-Ahead and Hour-Ahead Markets, capacity payments due the Scheduling Coordinator from each market will be rescinded in proportion to the amount of capacity sold to the ISO in each market.

2.5.26.2.5 Payment shall be eliminated first for any Replacement Reserve capacity for which the Generating Unit, Curtailable Demand, System Unit or System Resource would otherwise be entitled to payment. If the amount of Ancillary Service capacity from which the Generating Unit, System Unit or System Resource has supplied Uninstructed Imbalance Energy exceeds the amount of Replacement Reserve capacity for which it would otherwise be entitled to receive payment, payment shall be eliminated for Non-Spinning

Reserve capacity, and then for Spinning Reserve capacity, until payment has been withheld for the full amount of Ancillary Service capacity from which the Generating Unit, Curtailable Demand, System Unit or System Resource supplied Uninstructed Imbalance Energy.

2.5.26.2.6 For each Settlement Interval in which a Generating Unit, Curtailable Demand, System Unit or System Resource fails to actually supply Energy from Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity in accordance with a Dispatch Instruction, or supplies only a portion of the Energy specified in the Dispatch Instruction, the capacity payment will be pro-rated to reflect the unavailability in that Settlement Interval of the difference between (1) the total MW of the particular Ancillary Service scheduled in that Settlement Period and (2) the amount of Energy, if any, supplied in response to the Dispatch Instruction in that Settlement Interval.

2.5.26.3 Rescission of Payments When Dispatch Instruction is Not Followed

If the total metered output of a Generating Unit, Curtailable Demand, System Unit or System Resource is insufficient to supply the amount of Instructed Imbalance Energy associated with a Dispatch Instruction issued in accordance with a bid on Spinning Reserve, Non-Spinning Reserve, or Replacement Reserve in any Settlement Interval, then the capacity payment associated with the difference between the total scheduled amount of each Ancillary Service for which Insufficient Energy was delivered, and the actual output attributed to the response to the Dispatch Instruction on each Ancillary Service, shall be rescinded. However, no capacity payment shall be rescinded if the shortfall in the metered output of the Generating Unit, Curtailable Demand, System Unit, or System Resource is less than a deadband amount published by ISO on the ISO Home Page at least twenty-four hours prior to the Settlement Interval. For any Settlement Interval with respect to which no

deadband amount has been published by the ISO, the deadband amount shall be zero MWH. If the Generating Unit, Curtailable Demand, System Unit or System Resource is scheduled to provide more than one Ancillary Service in the Settlement Period, then the actual output will be attributed first to Replacement Reserve, then to Non-Spinning Reserve, and finally to Spinning Reserve, and the capacity payments associated with the balance of each Ancillary Service shall be rescinded. If the same Ancillary Service is scheduled in both the Day-Ahead and Hour-Ahead Markets, then payments shall be rescinded in proportion to the amount of each Ancillary Service scheduled in each market.

2.5.26.4 Penalties applied pursuant to Section 2.5.26.1, and payments rescinded pursuant to Section 2.5.26.2 and 2.5.26.3 shall be redistributed to Scheduling Coordinators in proportion to ISO Control Area metered Demand and scheduled exports for the same Trading Day.

2.5.26.5 If the ISO determines that non-compliance of a Load, Generating Unit, System Unit or System Resource, with an operating order or Dispatch Instruction from the ISO, or with any other applicable technical standard under the ISO Tariff, causes or exacerbates system conditions for which the WECC imposes a penalty on the ISO, then the Scheduling Coordinator of such Load, Generating Unit, System Unit or System Resource shall be assigned that portion of the WECC penalty which the ISO reasonably determines is attributable to such non-compliance, in addition to any other penalties or sanctions applicable under the ISO Tariff.

2.5.26.6 Temporary Exemption from Rescission of Energy Payments Any Participating Load that has entered into a Participating Load Agreement and has responded to a Dispatch Instruction will be exempt from the requirements of Section 2.5.26.2.3 in the hour of the Dispatch and for the following two (2) hours during the period beginning on June 15, 2000 and ending on the date specified in a notice ("Notice Terminating Temporary Exemption") to be issued by the ISO. Such notice shall be posted on the ISO Home Page and distributed to

2.5.27 Settlements For Contracted Ancillary Services.

Based on the prices and quantities determined in accordance with this Section, the ISO shall operate a daily Settlement function for Ancillary Services it contracts for with Scheduling Coordinators.

The ISO shall calculate imbalances between scheduled, instructed and actual quantities of Energy provided based upon Meter Data obtained pursuant to Section 10. Schedules between Control Areas shall be deemed as being delivered in accordance with Good Utility Practice. The difference between actual and scheduled interchange shall then be addressed in accordance with the WECC and NERC inadvertent interchange practices and procedures. Following this practice, all dynamic schedules for Ancillary Services provided to the ISO by other Control Areas shall be deemed delivered to the ISO. The difference between the Energy requested by the ISO and that actually delivered by the other Control Area shall then be accounted for and addressed through the WECC and NERC inadvertent interchange practices and procedures.

Separate payments shall be calculated for each Settlement Period t for each Generating Unit, System Unit, System Resource and Curtailable Demand. The ISO shall then calculate a total daily payment for each Scheduling Coordinator for all the Generating Units, System Units, System Resources and Curtailable Demands that it represents for each Settlement Period t.

The settlements for the Hour-Ahead Markets shall be calculated by substituting Hour-Ahead prices in the relevant formulae and deducting any amounts due to the ISO from Scheduling Coordinators who buy back in the Hour-Ahead Market Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity they sold to the ISO in the Day-Ahead Market.

2.5.27.1 Regulation.

Regulation Up and Regulation Down payments shall be calculated separately.

Quantities. The following quantity definitions shall be used for each Scheduling Coordinator in the settlement process:

$AGCUpQDA_{xt}$ = the Scheduling Coordinator's total quantity of Regulation Up capacity in Zone X sold through the ISO auction and scheduled Day-Ahead j for Settlement Period t.

$AGCDownQDA_{xt}$ = the Scheduling Coordinator's total quantity of Regulation Down capacity in Zone X sold through the ISO auction and scheduled Day-Ahead j for Settlement Period t.

$EnQInst_{xt}$ = Instructed Imbalance Energy increase or decrease in Zone X in real-time Dispatch for each Dispatch Interval b of Settlement Period t, determined in accordance with the ISO Protocols.

Prices. The prices in the Settlement process for Regulation Up and Regulation Down shall be those determined in Section 2.5.14.

Adjustment: penalty described in Section 2.5.26.1.

$PAGCUpDA_{xt}$ = the Market Clearing Price, PAGC, in Zone X for Regulation Up capacity in the Day-Ahead Market for Settlement Period t.

$PAGCDownDA_{xt}$ = the Market Clearing Price, PAGC, in Zone X for Regulation Down capacity in the Day-Ahead Market for Settlement Period t.

Payments. Scheduling Coordinators for Generating Units providing Regulation Up capacity through the ISO auction shall receive the following payments for Regulation Up:

$$AGCUpPay_{xt} = AGCUpQDA_{xt} * PAGCUpDA_{xt} - Adjustment$$

at a level that will provide sufficient incentive to the market to supply upward Regulation for the ISO's purposes of satisfying WECC criteria and NERC control performance standards. The ISO shall post the weighting factors consistent with the ISO Weighting Procedure, posted on the ISO website.

R_{DNixt} = the downward range of generating capacity for the provision of Regulation for Generating Unit i in Zone X included in the bid accepted by the ISO for Generating Unit i for Settlement Period t, weighted in proportion to the ISO's need for downward Regulation. The weighting factors will be specified within a range from 0-100 percent. The weighting factors will be set at the discretion of the ISO based on system conditions, and will be set at a level that will provide sufficient incentive to the market to supply downward Regulation for the ISO's purposes of satisfying WECC criteria and NERC control performance standards. The ISO shall post the weighting factors consistent with the ISO Weighting Procedure, posted on the ISO website.

C_{UP} = 0 to 1

C_{DN} = 0 to 1

P_{xt} = the Hourly Ex Post Price for Zone X in Settlement Period t.

The ISO may modify the value of the constants C_{UP} or C_{DN} within a range of 0-1 either generally in regard to all hours or specifically in regard to particular times of the day, after the ISO Governing Board approves such modification, by a notice issued by the Chief

Executive Officer of the ISO and posted on the ISO Internet "Home Page," at http//www.caiso.com, or such other Internet address as the ISO may publish from time to time, specifying the date and time from which the modification shall take effect, which shall be not less than seven (7) days after the Notice is issued.

REPA shall not be payable unless the Generating Unit is available and capable of being controlled and monitored by the ISO Energy Management System over the full range of its Scheduled Regulation capacity for the entire Settlement Period at least the ramp rates (increase and decrease in MW/minute) stated in its bid. In addition, the total Energy available (R_{UP} plus R_{DN}) may be adjusted to be only R_{UP} or only R_{DN}, a percentage of R_{UP} or R_{DN}, or the sum of R_{UP} and R_{DN}, depending on the needs of the ISO for each direction of Regulation service.

2.5.27.2 Spinning Reserve.

Quantities. The following quantity definitions shall be used for each Scheduling Coordinator in the Settlement process:

$SpinQDA_{xt}$ = the Scheduling Coordinator's total quantity of Spinning Reserve capacity in Zone X sold through the ISO auction and scheduled Day-Ahead for Settlement Period t.

$EnQInst_{xt}$ = Instructed Imbalance Energy output in Zone X in real-time Dispatch for Settlement Period t, supplied in accordance with the ISO Protocols.

Prices. The prices in the Settlement process for Spinning Reserve shall be those determined in Section 2.5.15.

$PspDA_{xt}$ = Market Clearing Price, Psp, in Zone X for Spinning Reserve capacity in the Day-Ahead Market for Settlement Period t.

Payments. Scheduling Coordinators for Generating Units, System Units, or System Resources providing Spinning Reserve capacity through the ISO auction shall receive the following payments for Spinning Reserve capacity:

$$SpinPay_{xt} = SpinQDA_{xt} * PspDA_{xt-Adjustment}$$

Scheduling Coordinators for Generating Units, System Units, or System Resources shall receive the following payments for Energy output from Spinning Reserve capacity:

$$EnQInst_{xt} * Resource\text{-}Specific\ Settlement\ Interval\ Ex\ Post\ Price_{xt}$$

2.5.27.3 Non-Spinning Reserve.

Quantities. The following quantity definitions shall be used for each Scheduling Coordinator in the Settlement process:

$NonSpinQDA_{xt}$ = the Scheduling Coordinator's total Quantity of Non-Spinning Reserve capacity in Zone X sold through the ISO's auction and scheduled Day-Ahead for Settlement Period t.

$EnQInst_{xt}$ = Instructed Imbalance Energy output or Demand reduction in Zone X in real-time Dispatch for Settlement Period t, supplied in accordance with the ISO Protocols.

Prices. The prices in the Settlement process for Non-Spinning Reserve shall be those determined in Section 2.5.16.

Adjustment = penalty described in Section 2.5.26.1, or rescinded capacity payments described in Section 2.5.26.2 or 2.5.26.3.

$PnonspDA_{xt}$ = Market Clearing Price, Pnonsp, in Zone X for Non-Spinning Reserve capacity in the Day-Ahead Market for Settlement Period t.

Payments. Scheduling Coordinators for Generating Units, System Units, System Resources, or Loads supplying Non-Spinning Reserve capacity through the ISO auction shall be paid the following for the Non-Spinning Reserve capacity:

$NonspPay_{xt} = NonSpinQDA_{xt} * PnonspDAxt - Adjustment$

Scheduling Coordinators for Generating Units, System Units, System Resources or Loads shall receive the following payments for Energy output from Non-Spinning Reserve capacity:

$EnQInst_{xt} * Resource\text{-}Specific\ Settlement\ Interval\ Ex\ Post\ Price_{xt}$

2.5.27.4 Replacement Reserve.

Quantities. The following quantity definitions shall be used for each Scheduling Coordinator in the Settlement process:

$RepResQDA_{xt}$ = the Scheduling Coordinator's total quantity of Replacement Reserve capacity in Zone X sold through the ISO auction scheduled Day-Ahead for Settlement Period t, and from which Energy has not been generated.

$EnQInst_{xt}$ = Instructed Imbalance Energy output or Demand reduction in Zone X in real-time Dispatch for Settlement Period t, supplied in accordance with the ISO Protocols.

Prices. The prices in the Settlement process for Replacement Reserve shall be those determined in Section 2.5.17.

Adjustment = penalty described in Section 2.5.26.1, or rescinded capacity payments described in Section 2.5.26.2 or 2.5.26.3.

$PRepResDA_{xt}$ = Market Clearing Price, PRepRes, in Zone X for Replacement Reserve capacity in the Day-Ahead Market for Settlement Period t.

Payments. Scheduling Coordinators for Generating Units, System Units, System Resources, or Loads providing Replacement Reserve capacity through the ISO auction shall receive the following payments for the portion of a Scheduling Coordinator's Replacement Reserve capacity from which Energy has not been generated:

$RepResPay_{ijt} = (RepResQDA_{xt} -) * PRepResDA_{xt\text{-}Adjustment}$

Scheduling Coordinators shall not receive capacity payments for the portion of a Scheduling Coordinator's Replacement Reserve capacity from which Energy has been generated. The payments for Energy output from Replacement Reserve capacity are calculated as follows:

$EnQInst_{ijt}$ * *Resource-Specific Settlement Interval Ex Post Price*$_{xt}$

2.5.27.5 Voltage Support. The total payments for each Scheduling Coordinator shall be the sum of the short-term procurement payments, based on opportunity cost, as described in Section 2.5.18, and the payments under long-term contracts.

2.5.27.6 Black Start.

Quantities. The following quantities shall be used in the Settlement process:

$EnQBS_{ijt}$ = Energy output from Black Start made by Generating Unit i from Scheduling Coordinator j (or Black Start Generator j, as the case may be) for Settlement Period t, pursuant to the ISO's order to produce.

Prices. The prices used in the Settlement process are those described in the contracts referred to in Section 2.5.19.

Adjustment = penalty described in Section 2.5.26.1.

Payments.

Scheduling Coordinators for owners of Reliability Must-Run Units (or Black Start Generators, as the case may be) shall receive the following payments for Energy output from Black Start facilities:

$BSEN_{ijt}=(EnQBS_{ijt}*EnBid_{ijt})+BSSUP_{ijt}-Adjustment$

where BSSUPijt is the start-up payment for a Black Start successfully made by Generating Unit i of Scheduling Coordinator j (or Black Start Generator j) in Trading Interval t calculated in accordance with the applicable Reliability Must-Run Contract (or the Interim Black Start Agreement as the case may be).

2.5.27.7 [Not Used]

2.5.27.7.1 [Not Used]

2.5.28 Settlement for User Charges for Ancillary Services.

(a) The ISO shall determine a separate hourly user rate for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve for each Settlement Period purchased in the Day-Ahead Market, and in the Hour-Ahead Market. Each rate will be charged to Scheduling Coordinators on a volumetric basis applied to each Scheduling Coordinator's obligation for the Ancillary Service concerned which it has not self-provided, as adjusted by any Inter-Scheduling Coordinator Ancillary Service Trades.

Each Scheduling Coordinator's obligation for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve for each Zone shall be calculated in accordance with Section 2.5.20.1, notwithstanding any adjustment to the quantities of each Ancillary Service purchased by the ISO in accordance with Section 2.5.3.6.

The cost of Voltage Support and Black Start shall be allocated to Scheduling Coordinators as described in Sections 2.5.28.5 and 2.5.28.6.

Quantities and rates for the Hour-Ahead Markets shall be calculated by substituting the Hour-Ahead quantities and prices in the relevant formulae (including self-provided quantities of the Ancillary Service) except that the user rates for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve capacity shall be calculated by dividing the net payments made by the ISO for each service by the MW quantity purchased for each service. The net payments are the total payments for each service net of sums payable by Scheduling Coordinators who have bought back in the Hour-Ahead Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity, as the case may be, which they had sold to the ISO in the Day-Ahead Market.

Ancillary Services obligations may be negative, and credits for such negative obligations will be in accordance with the rates calculated in Sections 2.5.28.1, 2.5.28.2, 2.5.28.3 and 2.5.28.4, except that a Scheduling Coordinator's credit shall be reduced by the greater of: a) the amount of any self-provision scheduled from resources which are deemed to meet the ISO's Ancillary Services standards, and which are not subject to the certification and testing requirements of the ISO Tariff; or b) if the ISO has no incremental requirement to be met in the Hour-Ahead Market for an Ancillary Service, the incremental amount of such service scheduled by that Scheduling Coordinator in the Hour-Ahead Market.

The ISO will allocate the Ancillary Services capacity charges, for both Day-Ahead and Hour-Ahead Markets, on a Zonal basis if the Day-Ahead Ancillary Services market is procured on a Zonal basis. The ISO will allocate the Ancillary Services capacity charges, for both the Day-Ahead and Hour-Ahead Markets, on an ISO Control Area wide basis if the Day-Ahead Ancillary Services market is defined on an ISO Control Area wide basis.

Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve of the amount, if any, by which (i) the total payments to Scheduling Coordinators pursuant to Section 2.5.27.1 through 2.5.27.4, for the Day-Ahead Market and Hour-Ahead Market and all Zones, exceed (ii) the total amounts charged to Scheduling Coordinators pursuant to Section 2.5.28.1 through 2.5.28.4, for the Day-Ahead Market and Hour-Ahead Market and all Zones. If total amounts charged to Scheduling Coordinators exceed the total payments to Scheduling Coordinators, each Scheduling Coordinator will be refunded its proportionate share, based on total purchases by Scheduling Coordinators of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve.

2.5.28.1 Regulation. Regulation Up and Regulation Down charges shall be calculated separately. The user rate per unit of purchased Regulation service for each Settlement Period in the Day-Ahead Market for each Zone shall be calculated by dividing the total Regulation capacity payments by the ISO's total MW purchases of Regulation for that Settlement Period for that Zone which has not been self-provided by Scheduling Coordinators. The ISO will calculate the user rate for Regulation Up in each Zone for each Settlement Period as:

$$RegRateUpDA\ (\$/MW) = AGCUpPayDA\ /AGCUpPurchDA$$

where:

$AGCUpPayDA$ = Total Regulation Up payments for the Settlement Period in the Day-Ahead Market for the Zone.

$AGCUpPurchDA$ = the total ISO Regulation Up MW purchases in the Day-Ahead Market for the Settlement Period for the Zone, excluding that which has been self-provided by Scheduling Coordinators.

The ISO will calculate the user rate for Regulation Down in each Zone for each Settlement Period as:

RegRateDownDA ($/MW) = AGCDownPayDA /AGCDownPurchDA

where:

AGCDownPayDA = Total Regulation Down payments for the Settlement Period in the Day-Ahead Market for the Zone.

AGCDownPurchDA = the total ISO Regulation Down MW purchases in the Day-Ahead Market for the Settlement Period for the Zone, excluding that which has been self-provided by Scheduling Coordinators.

For each Settlement Period, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone:

*RegRateUpDA * AGCUpOblig*

where *AGCUpOblig* is the Scheduling Coordinator's obligation for Regulation Up in the Zone in the Settlement Period for which it has not self-provided.

*RegRateDownDA * AGCDownOblig*

where *AGCDownOblig* is the Scheduling Coordinator's obligation for Regulation Down in the Zone in the Settlement Period for which it has not self-provided.

2.5.28.2 Spinning Reserve. The user rate per unit of purchased Spinning Reserve for each Settlement Period in the Day-Ahead Market for each Zone shall be calculated by dividing the total capacity payments for Spinning Reserve by the ISO's total MW purchases of Spinning Reserve for that Settlement Period for that Zone which has not

been self-provided by Scheduling Coordinators. The ISO will calculate the user rate for Spinning Reserve in each Zone for each Settlement Period as:

$$SpRateDA(\$/MW) = \frac{SpinPayDA}{SpinPurchDA}$$

where:

SpinPayDA = Total Spinning Reserve payments for the Settlement Period in the Market for the Zone Day-Ahead.

SpinPurchDA = the total ISO Spinning Reserve MW purchases in the Day-Ahead Market for the Settlement Period for the Zone, excluding that which has been self-provided by Scheduling Coordinators.

For each Settlement Period, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone:

SPRateDA * *SpinOblig*

where *SpinOblig* is the Scheduling Coordinator's obligation for Spinning Reserve in the Zone in the Settlement Period for which it has not self-provided.

2.5.28.3 Non-Spinning Reserve. The user rate per unit of purchased Non-Spinning Reserve for each Settlement Period in the Day-Ahead Market for each Zone shall be calculated by dividing the total capacity payments for Non-Spinning Reserve by the ISO's total MW purchases of Non-Spinning Reserve for that Settlement Period for that Zone which has not been self-provided by Scheduling Coordinators. The ISO will calculate the user rate for Non-Spinning Reserve in each Zone for each Settlement Period as:

$$NonSpRateDA(\$/MW) = \frac{NonSpinPayDA}{NonSpinPurchDA}$$

where:

NonSpinPayDA = Total Non-Spinning Reserve payments for the Settlement Period in the Day-Ahead Market for the Zone.

NonSpinPurchDA = the total ISO Non-Spinning Reserve MW purchases for the Settlement Period for the Zone, excluding that which has been self-provided by Scheduling Coordinators.

For each Settlement Period, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone:

NonSpRateDA * *NonSpinOblig*

where *NonSpinOblig* is the Scheduling Coordinator's obligation for Non-Spinning Reserve in the Zone in the Settlement Period for which it has not self-provided.

2.5.28.4 Replacement Reserve. The user rate per unit of Replacement Reserve obligation for each Settlement Period t for each Zone x shall be as follows:

$$ReplRate_{xt} = \frac{(PRepResDA_{xt} * OrigReplReqDA_{xt}) + (PRepResHA_{xt} * OrigReplReqHA_{xt})}{OrigReplReqDA_{xt} + OrigReplReqHA_{xt}}$$

where

$OrigReplReqDA_{xt}$ = Replacement Reserve requirement net of self-provision in the Day-Ahead Market before consideration of any substitutions pursuant to Section 2.5.3.6.

$OrigReplReqHA_{xt}$ = Incremental change in the Replacement Reserve requirement net of

self-provision between the Day-Ahead Market and the Hour-Ahead Market before consideration of any substitutions pursuant to Section 2.5.3.6.

$PRepResDA_{xt}$ is the Market Clearing Price for Replacement Reserve in the Day-Ahead Market for Zone *x* in Settlement Period *t*.

$PRepResHA_{xt}$ is the Market Clearing Price for Replacement Reserve in the Hour-Ahead Market for Zone *x* in Settlement Period *t*.

For each Settlement Period t, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each $Zone_x$:

$ReplRate_{xt} * ReplOblig_{jxt}$

where

$$ReplOblig_{jxt} = DevReplOblig_{jxt} + RemRepl_{jxt} - SelfProv_{jxt} + NetInterSCTrades_{jxt}$$

$DevReplOblig_{jxt}$ is the Scheduling Coordinator's obligation for deviation Replacement Reserve in Zone x in the Settlement Period t and $RemRepl_{jxt}$ is the Scheduling Coordinator's obligation for remaining Replacement Reserve in Zone x for Settlement Period t.

$SelfProv_{jxt}$ is Scheduling Coordinator's Replacement Reserve self-provision in Zone x for Settlement Period t.

$NetInterSCTrades_{jxt}$ is the sale of Replacement Reserve less the purchase of Replacement Reserve through Inter-Scheduling Coordinator Trades by Scheduling Coordinator j in Zone x for Settlement Period t.

Deviation Replacement Reserve for Scheduling Coordinator j in Zone x for Settlement Period t is calculated as follows:

If $ReplObligTotal_{xt} > TotalDeviations_{xt}$ then:

$$DevReplOblig_{xjt} = \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]$$

If $ReplObligTotal_{xt} < TotalDeviations_{xt}$ then:

$$DevReplOblig_{xjt} = \frac{ReplObligTotal_{xt}}{TotalDeviations_{xt}} * \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]$$

where,

$$TotalDeviations_{xt} = \sum_j \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]$$

$GenDev_{ijxt}$ = The deviation between scheduled and actual Energy Generation for Generator i represented by Scheduling Coordinator j in Zone x during Settlement Period t as referenced in SABP Appendix D.

$LoadDev_{ijxt}$ = The deviation between scheduled and actual Load consumption for resource i represented by Scheduling Coordinator j in Zone x during Settlement Period t as referenced in SABP Appendix D.

$DevReplOblig_{xt}$ is total deviation Replacement Reserve in Zone x for Settlement Period t.

$ReplObligTotal_{xt}$ is total Replacement Reserve Obligation in Zone x for Settlement Period t.

Remaining Replacement Reserve for Scheduling Coordinator j in Zone x for Settlement Period t is calculated as follows:

$$RemRepl_{xjt} = \frac{MeteredDemand_{jxt}}{TotalMeteredDemand_{xt}} * Total\,Rem\,Repl_{xt}$$

where:

$MeteredDemand_{jxt}$ is the Scheduling Coordinator's total metered Demand excluding exports in Zone x for Settlement Period t.

$TotalMeteredDemand_{xt}$ is total metered Demand excluding exports in Zone x for Settlement Period t.

$TotalRemRepl_{xt} = Max[0, ReplObligTotal_{xt} + TotalSelfProv_{xt} - DevReplOblig_{xt}]$

2.5.28.5 Voltage Support. The short-term market Voltage Support user rate for Settlement Period t for Zone x shall be calculated as follows:

$$VSSTRate_{xt} = \frac{\sum_{i,j} VSST_{xijt}}{\sum_{j} QChargeVS_{xjt}}$$

$VSST_{xijt}$ = Voltage Support payment to Scheduling Coordinator j in respect of Generating Unit i in Zone x in the short-term market applicable to Settlement Period t.

$QChargeVS_{xjt}$ = charging quantity for Voltage Support for Scheduling Coordinator j for Settlement Period t in Zone x equal to the total metered Demand in Zone x (including exports to neighboring Control Areas and excluding metered Demand inside an MSS) by Scheduling Coordinator j for Settlement Period t.

The monthly long-term Voltage Support contract user rate for Settlement Period t for Zone x shall be calculated as follows:

$$VSLTRate_{xm} = \frac{\sum_{i,j} VSLT_{xijm}}{\sum_{jm} QChargeVS_{xjt}}$$

where:

$VSLT_{xijm}$ = long-term Voltage Support contract payment to Scheduling Coordinator j for owner of Reliability Must-Run Unit i in Zone x for month m.

The short-term market Voltage Support charges for Settlement Period t payable by Scheduling Coordinator j will be calculated as follows:

$$VSSTCharge_{jt} = VSSTRate_t * QCharge VS_{jt}$$

where $VSSTCharge_{jt}$ is the amount payable by Scheduling Coordinator j for short-term market Voltage Support for Settlement Period t.

$VSSTRate_t$ is the short-term market Voltage Support user rate for Settlement Period t.

The monthly long-term Voltage Support contract charge for month m payable by Scheduling Coordinator j will be calculated as follows:

$$VSLTCharge_m = VSLTRate_m * \sum_m QCharge VS_{jt}$$

where $VSLTCharge_m$ is the amount payable by Scheduling Coordinator j for long-term Voltage Support for month m.

$VSLTRate_m$ is the monthly long-term Voltage Support contract user rate charged by the ISO to Scheduling Coordinators for month m.

2.5.28.6 Black Start.

$QChargeBlackstart_{jt}$ = charging quantity for Black Start for Scheduling Coordinator j for Settlement Period t equal to the total metered Demand (excluding exports to neighboring Control Areas and metered Demand of a MSS) by Scheduling Coordinator j for Settlement Period t.

The Black Start Energy payment user rate for Settlement Period t will be calculated as follows:

$$BSRate_t = \frac{\sum_{i,j} BSEn_{ijt}}{\sum_{j} QChargeBlackstart_{jt}}$$

where $BSEn_{ijt}$ is the ISO payment to Scheduling Coordinator j for owner of Reliability Must-Run Unit (or to Black Start Generator j, as the case may be) for Generating Unit i providing Black Start Energy in Settlement Period t.

The Black Start Energy user charge for Settlement Period t for Scheduling Coordinator j will be calculated as follows:

$$BSCharge_{jt} = BSRate_t * QChargeBlackStart_{jt}$$

2.5.29 Public Dissemination of Information: Day-Ahead.

By 3:00 p.m. of the day preceding the Trading Day, the ISO shall make available to all Market Participants the following information on the scheduling of Ancillary Services:

Ancillary Service	Quantity Units	Period	Clearing Prices
Regulation/AGC	MW	Hourly	$/MW
Spinning Reserve	MW	Hourly	$/MW
Non-Spinning Reserve	MW	Hourly	$/MW
Replacement Reserve	MW	Hourly	$/MW
Black Start	MW	Annual	$/MW

2.5.30 Communication Protocols.

Communications between the ISO and Scheduling Coordinators shall be as described below:

2.5.30.1 Information Transfer from Scheduling Coordinator to ISO. Unless otherwise agreed by the ISO, Scheduling Coordinators who wish to schedule or bid Ancillary Services to the ISO must submit the information by direct computer link.

2.5.30.2 Submitting Information By Direct Computer Link. For Scheduling Coordinators submitting information by direct computer link, each such Scheduling Coordinator shall establish a network connection with the ISO through the WEnet network. This shall be a permanent link with the ISO. Link initialization procedures shall be necessary to establish the connection for the first time, and to re-establish the connection each time the connection is restored after a system or communication failure. In order to log in, each Scheduling Coordinator shall furnish the ISO with user ID and password.

3.2.1 Determination of Need.

A Participating TO or any other Market Participant may propose a transmission system addition or upgrade. The ISO will determine that a transmission addition or upgrade is needed where it will promote economic efficiency or maintain System Reliability as set forth below.

3.2.1.1 Economically Driven Projects. The Participating TO and Market Participants shall provide the necessary assistance and information to the ISO, as part of the coordinated planning process, to enable the ISO to determine that a project is needed to promote economic efficiency, including, at the ISO's discretion, studies comporting with ISO guidelines that demonstrate whether the project will promote economic efficiency or the information the ISO requires to carry out its own studies for economically driven projects. The ISO shall treat market sensitive information provided to the ISO in accordance with this Section by Participating TOs, Project Sponsors and applicable Market Participants confidentially in accordance with Section 20.3 provided that such information is clearly marked "Confidential" at the time it is provided to the ISO. The determination that a transmission addition or upgrade is needed to promote economic efficiency shall be made in any of the following ways:

additions or upgrades) using an economic analysis that comports with ISO guidelines, and (2) a statement of the proposed pricing methodology for the transmission upgrades or additions that the Project Sponsor elects in accordance with Section 3.2.7 of the ISO Tariff.

3.2.1.1.3.2 If neither any Market Participant nor the ISO disputes the Project Sponsor's showing, then the proposal is determined to be needed.

3.2.1.1.3.3 If any Market Participant or the ISO disputes the Project Sponsor's showing, the disputing Market Participant, the ISO, or the Project Sponsor may submit to resolution through the ISO ADR Procedure the issue of whether the transmission addition or upgrade is needed on the ground that its economic benefits exceed its costs. If a Market Participant fails to raise through the ISO ADR Procedure a dispute as to whether a proposed transmission addition or upgrade is needed, then the Market Participant shall be deemed to have waived its right to raise such dispute at a later date. The determination under the ISO ADR Procedure as to whether the transmission addition or upgrade is needed, including any determination by FERC or on appeal of a FERC determination in accordance with that process, shall be final.

3.2.1.2 Reliability Driven Projects. The ISO in coordination with the Participating TO, will identify the need for any transmission additions or upgrades required to ensure System Reliability consistent with all Applicable Reliability Criteria. In making this determination, the ISO, in coordination with the Participating TO and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as acceleration or expansion of existing projects, demand-side management,

remedial action schemes, constrained-on Generation, interruptible Loads or reactive support. The Participating TO, in cooperation with the ISO, shall perform the necessary studies to determine the facilities needed to meet all Applicable Reliability Criteria. The Participating TO shall provide the ISO and other Market Participants with all information relating to a proposed transmission addition or upgrade that they may reasonably request (other than information available to them through the WECC or any other applicable regional organization) and shall, through the WECC or any other applicable regional organization coordinated planning processes, develop the scope of and assumptions for such studies that are acceptable to the ISO and those other Market Participants. The ISO shall be free to propose any transmission upgrades or additions it deems necessary to ensure System Reliability consistent with Applicable Reliability Criteria, and, subject to appropriate appeals, the Participating TO shall be obligated to construct such lines. After the ISO Operations Date, the ISO, in consultation with Participating TOs and any affected UDCs and MSSs, will work to develop a consistent set of Reliability Criteria for the ISO Controlled Grid which the Participating TOs will use in their transmission planning and expansion studies or decisions.

3.2.2 Transmission Planning and Coordination.

The ISO shall actively participate with each Participating TO and the other Market Participants in the ISO Controlled Grid planning process in accordance with the terms of this ISO Tariff and the Transmission Control Agreement.

3.2.2.1 Each Participating TO shall develop annually a transmission expansion plan covering a minimum five-year planning horizon for its PTO Service Area. Such Participating TO shall coordinate with the ISO and other Market Participants in the development of such plan. The Participating TO shall be responsible for ensuring that its transmission expansion plan meets all Applicable Reliability Criteria.

3.2.2.2 The ISO shall review the Participating TOs' transmission expansion plans to ensure that each Participating TO's expansion plans meet the Applicable Reliability Criteria. The Participating TO will provide the necessary assistance and information as part of the coordinated planning process to the ISO to enable it to carry out its own studies for these purposes. If the ISO finds that the Participating TO's plan or projects do not meet the Applicable Reliability Criteria, the ISO will provide comments and the Participating TO will reassess its plans, as appropriate. The ISO may also propose new projects or suggest project changes (*e.g.*, timing, project size) for consideration by the Participating TO. Changes or additions made by the ISO and accepted by the TO will be included in the Participating TO's expansion plan. Changes or additions not accepted in the coordinated planning process will be resolved through the ISO ADR Procedure.

3.2.2.3 The Participating TO will act as a Project Sponsor for Participating TO proposed economic or reliability projects that are included in its expansion plan. The Participating TO shall provide to the ISO any information that the ISO requires to enable the ISO to comply with WECC and any other applicable regional coordination requirements pursuant to Section 3.2.6.

3.2.2.4 The ISO will be a member of the WECC and other applicable regional organizations and participate in WECC's operation and planning committees, and in other applicable regional coordinated planning processes. Neither the ISO nor any Participating TO nor any Market Participant shall take any position before the WECC or a regional organization that is inconsistent with a binding decision reached through the ISO ADR Procedure.

3.2.3 Studies to Determine Facilities to be Constructed.

Where a Participating TO is obligated to construct or expand facilities in accordance with this ISO Tariff or where the ISO or any Market Participant requests that a Facility Study be

promptly notify the ISO and the Project Sponsor and shall comply with its obligations under the TO Tariff to convene a technical meeting to evaluate alternative proposals. The ISO shall take such action as it reasonably considers appropriate, in coordination with the Participating TO, the Project Sponsor (if any) and other affected Market Participants, to facilitate the development and evaluation of alternative proposals including, where possible, conferring on a third party the right to build the transmission addition or upgrade.

3.2.5.3 Where it is possible for a third party to obtain all approvals and property rights under applicable federal, state and local laws that are necessary to complete the construction of transmission additions or upgrades required to be constructed in accordance with this ISO Tariff (including the use of eminent domain authority, where provided by state law) the ISO may confer on a third party the right to build the transmission addition or upgrade which shall enter into the Transmission Control Agreement in relation to such transmission addition or upgrade.

3.2.6 WECC and Regional Coordination.

The Project Sponsor will have responsibility for completing any applicable WECC requirements and other applicable regional coordination and rating study requirements to ensure that a proposed transmission addition or upgrade meets regional planning requirements. The Project Sponsor may request the Participating TO to perform this coordination on behalf of the Project Sponsor at the Project Sponsor's expense.

3.2.7 Cost Responsibility for Transmission Additions or Upgrades.

Cost responsibility for transmission additions or upgrades constructed pursuant to this Section 3.2 (including the responsibility for any costs incurred under Section 3.2.6) shall be determined as follows:

4. RELATIONSHIP BETWEEN ISO AND UDCS.

4.1 General Nature of Relationship Between ISO and UDCs.

4.1.1 The ISO shall not be obliged to accept Schedules, Adjustment Bids or bids for Ancillary Services which would require Energy to be transmitted to or from the Distribution System of a UDC directly connected to the ISO Controlled Grid unless the relevant UDC has entered into a UDC Operating Agreement. The UDC Operating Agreement shall require UDCs to comply with the applicable provisions of this Section 4 and any other expressly applicable Sections of this ISO Tariff and the ISO Protocols as these may be amended from time to time. The ISO shall maintain a pro forma UDC Operating Agreement available for UDCs to enter into with the ISO.

4.1.2 The ISO shall operate the ISO Controlled Grid, and each UDC shall operate its Distribution System at all times in accordance with Good Utility Practice and in a manner which ensures safe and reliable operation. The ISO shall, in respect of its obligations set

forth in this Section 4, have the right by agreement to delegate certain operational responsibilities to the relevant Participating TO or UDC pursuant to this Section 4. All information made available to UDCs by the ISO shall also be made available to Scheduling Coordinators. All information pertaining to the physical state or operation, maintenance and failure of the UDC Distribution System affecting the operation of the ISO Controlled Grid that is made available to the ISO by the UDC shall also be made available to Scheduling Coordinators upon receipt of reasonable notice.

4.2 Coordinating Maintenance Outages of UDC Facilities.

Each UDC and the Participating TO with which it is interconnected shall coordinate their Outage requirements that will have an effect on their transmission interconnection prior to the submission by that Participating TO of its Maintenance Outage requirements under Section 2.3.3.

4.3 UDC Responsibilities.

Recognizing the ISO's duty to ensure efficient use and reliable operation of the ISO Controlled Grid consistent with the Applicable Reliability Criteria, each UDC shall:

4.3.1 operate and maintain its facilities, in accordance with applicable safety and reliability standards, regulatory requirements, applicable operating guidelines, applicable rates, tariffs, statutes and regulations governing their provision of service to their End-Use Customers and Good Utility Practice so as to avoid any material adverse impact on the ISO Controlled Grid;

4.3.2 provide the ISO Outage Coordination Office each year with a schedule of upcoming maintenance that has a reasonable potential of impacting the ISO Controlled Grid in accordance with Section 2.3.3.5 of this ISO Tariff; and

4.4.4 The ISO shall have the authority to direct a UDC to disconnect Load from the ISO Controlled Grid if necessary to avoid an anticipated System Emergency or to regain operational control over the ISO Controlled Grid during an actual System Emergency. The ISO shall direct the UDCs to shed Load in accordance with the prioritization schedule developed pursuant to Section 2.3.2.6. When ISO Controlled Grid conditions permit restoration of Load, the ISO shall restore Load according to the prioritization schedule developed pursuant to Section 2.3.2.6 hereof.

4.5 Electrical Emergency Plan (EEP).

4.5.1 The ISO shall in accordance with Section 2.3.2.4 hereof implement the Electrical Emergency Plan in consultation with the UDCs or other entities, at the ISO's discretion, when Energy reserve margins are forecast to be at the levels specified in the plan.

4.5.2 Each UDC will notify its End-Use Customers connected to its Distribution System of any voluntary curtailments notified to the UDC by the ISO pursuant to the provisions of the EEP.

4.5.3 Load Shedding

4.5.3.1 A portion of the ISO forecast of Control Area Load for each Trading Day will be allocated to each UDC or MSS Service Area. The ISO will aggregate each Scheduling Coordinator's Day-Ahead Schedules to Load in each UDC or MSS Service Area and will compare those aggregated Load Schedules to the ISO's Control Area Load forecast of metered Demand for that UDC or MSS Service Area to determine if the Load in the UDC or MSS Service Area has a resource deficiency based on the Day-Ahead Schedules.

4.5.3.2 If the ISO forecasts in advance of the Hour-Ahead Market that Load curtailment will be necessary due to a resource deficiency, the ISO will identify any UDC or MSS Service Area that is resource deficient. The ISO will provide notice to all Scheduling Coordinators if one or more UDC or

4.6.2 Each UDC shall cooperate with the ISO in the preparation of an Outage review pursuant to Section 2.3.2.9.

4.7 Coordination of Expansion or Modifications to UDC Facilities.

Each UDC and the Participating TO with which it is interconnected shall coordinate in the planning and implementation of any expansion or modifications of a UDC's or Participating TO's system that will affect their transmission interconnection, the ISO Controlled Grid or the transmission services to be required by the UDC. The Participating TO shall be responsible for coordinating with the ISO.

4.8 Information Sharing.

4.8.1 System Planning Studies.

The ISO, Participating TOs and UDCs shall share information such as projected Load growth and system expansions necessary to conduct necessary System Planning Studies to the extent that these may impact the operation of the ISO Controlled Grid.

4.8.2 System Surveys and Inspections.

The ISO and each UDC shall cooperate with each other in performing system surveys and inspections to the extent these relate to the operation of the ISO Controlled Grid.

4.8.3 Reports.

4.8.3.1 The ISO shall make available to the UDCs any public annual reviews or reports regarding performance standards, measurements and incentives relating to the ISO Controlled Grid and shall also make available, upon reasonable notice, any such reports that the ISO receives from the Participating TOs. Each UDC shall make available to the ISO any public annual reviews or reports regarding performance standards,

5.2.1.2 If, at any time after the issuance of Final Day-Ahead Schedules for the Trading Day –

(1) the ISO determines that it requires more of an Ancillary Service than it has procured;

(2) all additional Day-Ahead bids for that Ancillary Service that have not been withdrawn (including any unused bids that can be used to satisfy that particular Ancillary Services requirement under Section 2.5.3.6) have been selected pursuant to Section 2.5.21, except that the ISO shall not be required to accept bids that exceed price caps imposed by the ISO or the FERC;

(3) the ISO has notified Scheduling Coordinators of the circumstances existing in paragraphs (1) and (2) of this Section 5.2.1.2; and

(4) after such notice, the ISO determines that a Bid Insufficiency condition exists in the Hour-Ahead Market for the Settlement Period in which the ISO requires more of an Ancillary Service;

the ISO may call upon Reliability Must-Run Units under Reliability Must-Run Contracts to meet the additional needs in addition to any amounts that the ISO has called upon under Section 5.2.1.1. The ISO must provide the notice specified in paragraph (3) of this Section 5.2.1.2 as soon as possible after the ISO determines that additional Ancillary Services are needed for which bids are not available. The ISO may only determine that a Bid Insufficiency exists in the Hour-Ahead Market after the close of the Hour-Ahead Market, unless an earlier determination is required in order to accommodate the Reliability Must-Run Unit's operating constraints. For the purposes of this Section, a Bid Insufficiency exists in an Hour-Ahead Market if, and only if –

(a) bids in the Hour-Ahead Market for the particular Ancillary Service (including any unused bids that can be used to satisfy that particular Ancillary Services requirement under Section 2.5.3.6) that remain after first procuring the megawatts of the Ancillary

Service that the ISO had notified Scheduling Coordinators it would procure in the Hour-Ahead Market pursuant to Section 2.5.12 ("remaining Ancillary Service requirement") represent, in the aggregate, less than two times such remaining Ancillary Service requirement; or

(b) there are less than two unaffiliated bidders to provide such remaining Ancillary Service requirement.

If a Bid Insufficiency condition exists, the ISO may nonetheless accept available market bids if it determines in its sole discretion that the prices bid and the supply curve created by the bids indicate that the bidders were not attempting to exercise market power.

5.2.2 [Not Used]

5.2.3 The ISO will, subject to any existing power purchase contracts of a Generating Unit, have the right at any time based upon ISO Controlled Grid technical analyses and studies to designate a Generating Unit as a Reliability Must-Run Unit. A Generating Unit so designated shall then be obligated to provide the ISO with its proposed rates for Reliability Must-Run Generation for negotiation with the ISO. Such rates shall be authorized by FERC or the Local Regulatory Authority, whichever authority is applicable.

5.2.4 [Not Used]-

5.2.5 On a yearly basis, the ISO will carry out technical evaluations based upon historic patterns of the operation of the ISO Controlled Grid and the ISO's forecast requirements for maintaining the reliability of the ISO Controlled Grid in the next year. The ISO will then determine which Generating Units it requires to continue to be Reliability Must-Run Units, which Generating Units it no longer requires to be Reliability Must-Run Units and which Generating Units it requires to become the subject of a Reliability Must-Run Contract which had not previously been so contracted to the ISO.

5.2.6 A *pro forma* of the Reliability Must-Run Contract is attached as Appendix G. From the ISO Operations Date all Reliability Must-Run Units will be placed under the "As Called" conditions, but the parties may, pursuant only to the terms of the Reliability Must-Run Contract, Transfer any such unit to one of the alternative forms of conditions under specific circumstances. The ISO will review the terms of the applicable forms of agreement applying to each Reliability Must-Run Unit to ensure that the ISO will procure Reliability Must-Run Generation from the cheapest available sources and to maintain System Reliability. The ISO shall give notice to terminate Reliability Must-Run Contracts that are no longer necessary or can be replaced by less expensive and/or more competitive sources for maintaining the reliability of the ISO Controlled Grid.

5.2.7 Reliability Must-Run Charge. The ISO shall prepare and send to each Responsible Utility in accordance with Annex 1 to the ISO's Settlement and Billing Protocol an ISO Invoice in respect to those costs incurred under each Reliability Must-Run Contract that are payable to the ISO by such Responsible Utility or payable by the ISO to such Responsible Utility pursuant to Section 5.2.8. The ISO Invoices shall reflect all reductions or credits required or allowed under or arising from the Reliability Must-Run Contract or under this Section 5.2.7. The ISO Invoice shall separately show the amounts due for services from each RMR Owner. Each Responsible Utility shall pay the amount due under each ISO Invoice by the due date specified in the ISO Invoice, in default of which interest shall become payable at the interest rate provided in the Reliability Must-Run Contract from the due date until the date on which the amount is paid in full. For each Reliability Must-Run Contract, the ISO shall establish two, segregated commercial bank accounts under the "Facility Trust Account" referred to in Annex 1 to the ISO's Settlement and Billing Protocol and Article 9 of the Reliability Must-Run Contract. One commercial bank account, the "RMR Owner Facility Trust Account," shall be held in trust

5.2.7.1.1 If the Responsible Utility disputes an ISO Invoice, Revised Estimated RMR Invoice, or Revised Adjusted RMR Invoice, or Final Invoice, it shall pay the ISO Invoice but may pay under protest and reserve its right to seek a refund, with interest, from the ISO. If resolution of the dispute results in an amount paid by the Responsible Utility under protest being due from the ISO to the Responsible Utility and from the RMR Owner to the ISO, and such amount was paid to the RMR Owner by the ISO, then such amount, with interest at the interest rate specified in the applicable Reliability Must-Run Contract from the date of payment until the date on which the amount is repaid in full, shall be refunded by the RMR Owner to the ISO and from the ISO to the Responsible Utility, pursuant to Article 9 of the Reliability Must-Run Contract and Annex 1 to the ISO's Settlement and Billing Protocol, by the RMR Owner's inclusion of such refund amount in the appropriate invoice. If the RMR Owner does not include such refund amount (including interest) in the appropriate invoice, then such refund amount shall be deducted by the ISO from the next succeeding amounts otherwise due from the Responsible Utility to the ISO and from the next succeeding amounts otherwise due from the ISO to the RMR Owner with respect to the applicable Reliability Must-Run Contract or, if such Contract has terminated, such amount shall be refunded by the ISO to the Responsible Utility; provided, however, that if and to the extent that such resolution is based on an error or breach or default of the RMR Owner's obligations to the ISO under the Reliability Must-Run Contract, then such refund obligation shall extend only to amounts actually collected by the ISO from the RMR Owner as a result of such resolution. If resolution of the dispute requires the ISO, but not the RMR Owner, to pay the Responsible Utility, then such award shall be recovered from any applicable insurance proceeds, provided that to the extent sufficient funds are not recoverable through insurance, the amount of the award (whether determined through settlement, or ADR or otherwise) shall be collected by the ISO pursuant to Section 13.5, and in any event, the award shall be paid by the ISO to the Responsible Utility pursuant to Section 13.5.

5.2.7.1.3 If the Responsible Utility disputes an ISO Invoice, a Revised Estimated RMR Invoice, a Revised Adjusted RMR Invoice, or a Final Invoice, based in whole or in part on an alleged error by the ISO or breach or default of the ISO's obligations to the Responsible Utility, the Responsible Utility shall notify the ISO of such dispute prior to the later to occur of (i) the date 12 months following the date on which the ISO submitted such invoice to the Responsible Utility for payment or (ii) the date 60 days following the date on which a final report is issued in connection with an operational audit, pursuant to Section 12.2.2, of the ISO's performance of its obligations to Responsible Utilities under this Section 5.2.7 conducted by an independent third party selected by the ISO Governing Board and covering the period to which such alleged dispute relates. The ISO or any Responsible Utility shall have the right to request, but not to require, that the ISO Governing Board arrange for such an operational audit at any time.

5.2.7.1.4 Notwithstanding Section 13 of this ISO Tariff, any Responsible Utility dispute relating to an ISO Invoice, a Revised Estimated Invoice, a Revised Adjusted Invoice, a Final Invoice, or a RMR Charge, RMR Payment or RMR Refund as defined in Annex 1 to the Settlement and Billing Protocol, shall be resolved through the dispute resolution process specified in the relevant RMR Contract. If the Responsible Utility fails to notify the ISO of any dispute as provided above, it shall be deemed to have validated the invoice and waived its right to dispute such invoice.

5.2.7.2 The RMR Owner shall, to the extent set forth herein, be a third party beneficiary of, and have all rights that the ISO has under the ISO Tariff, at law, in equity or otherwise, to enforce the Responsible Utility's obligation to pay all sums invoiced to it in the ISO Invoices but not paid by the Responsible Utility, to the extent that, as a result of the Responsible Utility's failure to pay, the ISO does not Pay the RMR Owner on a timely basis amounts due under the Reliability Must-Run Contract. The RMR Owner's rights as a third party beneficiary shall be no greater than the ISO's rights and shall be subject to the dispute resolution process specified in the relevant RMR Contract. Either the ISO or the

5.2.8.1 Responsibility for Reliability Must-Run Charges Associated with SONGS. If the ISO procures Reliability Must-Run Generation from the San Onofre Nuclear Generation Station Units 2 or 3, it shall determine prior to the operation of such facilities as Reliability Must-Run Generation the appropriate allocation of associated charges, if any, among Responsible Utilities. The allocation of such charges shall be based on the reliability benefits that the ISO reasonably identifies through studies and analysis as accruing to the respective Service Areas of the Responsible Utilities.

5.3 Identification of Generating Units.

Each Generator shall provide data identifying each of its Generating Units and such information regarding the capacity and the operating characteristics of the Generating Unit as may be reasonably requested from time to time by the ISO.

5.4 WECC Requirements.

5.4.1 Generator Performance Standard.

Participating Generators shall, in relation to each of their Generating Units, meet all applicable WECC standards including any standards regarding governor response capabilities, use of power system stabilizers, voltage control capabilities and hourly Energy delivery. Unless otherwise agreed by the ISO, a Generating Unit must be capable of operating at capacity registered in the ISO Controlled Grid interconnection data, and shall follow the voltage schedules issued by the ISO from time to time.

5.4.2 Reliability Criteria.

Participating Generators shall comply with the requirements of the WSCC Reliability Criteria Agreement, including the applicable WSCC Reliability Criteria set forth in Section IV of Annex A thereof. In the event that a Participating Generator fails to comply, it will be subject to the sanctions

applicable to such failure. Such sanctions shall be assessed pursuant to the procedures contained in the WSCC Reliability Criteria Agreement. Each and all of the provisions of the WSCC Reliability Criteria Agreement are hereby incorporated by reference into this Section 5.4.2 as though set forth fully herein, and Participating Generators shall for all purposes be considered Participants as defined in that Agreement, and shall be subject to all of the obligations of Participants, under and in connection with the WSCC Reliability Criteria Agreement. The Participating Generators shall copy the ISO on all reports supplied to the WECC in accordance with Section IV of Annex A of the WSCC Reliability Criteria Agreement.

5.4.3 Payment of Sanctions.

Each Participating Generator shall be responsible for payment directly to the WECC of any monetary sanction assessed against that Participating Generator by the WECC pursuant to the WSCC Reliability Criteria Agreement. Any such payment shall be made pursuant to the procedures specified in the WSCC Reliability Criteria Agreement.

5.5 Outages.

5.5.1 Planned Maintenance.

Each Participating Generator shall comply with the applicable provisions of Section 2.3.3.

5.5.2 The ISO shall, on the basis of the information supplied by Participating Generators under Section 5.5.1 and other information available to the ISO, prepare and publish on WEnet forecast aggregate available Generation capacity and forecast Demand on an annual, quarterly and monthly basis in accordance with the provisions of the ISO Outage Coordination Protocol. In publishing these forecasts, the ISO shall identify any expected Congestion conditions caused by planned Outages of Participating Generators.

5.5.3 Forced Outages.

Procedures equivalent to those set out in Section 2.3.3 shall apply to all Participating Generators in relation to Forced Outages.

5.6 System Emergencies.

5.6.1 All Generating Units, System Units and System Resources that are owned or controlled by a Participating Generator are (without limitation to the ISO's other rights

Study. If a New Facility Operator elects neither to execute the System Impact Study Agreement nor to rely upon the ISO ADR Procedures, such New Facility Operator's Completed Application will be deemed withdrawn. If the New Facility Operator's application is deemed withdrawn, the New Facility Operator will compensate the Interconnecting PTO for all reasonable costs incurred to that date in processing the Completed Interconnection Application.

The Interconnecting PTO will use due diligence to complete the System Impact Study within 60 calendar days of receipt of payment and the System Impact Study Agreement or initiation of the ISO ADR Procedures. If the Interconnecting PTO cannot complete the System Impact Study within 60 calendar days, the Interconnecting PTO will notify the New Facility Operator, in writing, of the reason why additional time is required to complete the required study and the estimated completion date.

5.7.4.2.2 Facility Study Procedures.

If a System Impact Study indicates that additions or upgrades to the ISO Controlled Grid are needed to satisfy a New Facility Operator's request for interconnection, the Interconnecting PTO shall, within 15 Business Days of the completion of the System Impact Study, tender to a New Facility Operator a Facility Study Agreement that defines the scope, content, assumptions and terms of reference for such study, the estimated time to complete the required study, and pursuant to which the applicant agrees to reimburse the Interconnecting PTO for the actual costs of performing the required Facility Study. The New Facility Operator shall execute the Facility Study Agreement and return it to the Interconnecting PTO within 10 Business Days, together with payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the Facility Study. Alternatively, a New Facility Operator may request that the Interconnecting PTO proceed with the Facility Study and abide by the terms, conditions, and cost assignment of the Facility Study Agreement ultimately determined through the ISO ADR

Procedures, provided that such request is accompanied by payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the Facility Study. If a New Facility Operator elects either to not execute the Facility Study Agreement or to rely upon the ISO ADR Procedures, such New Facility Operator's Completed Application will be deemed withdrawn. If the New Facility Operator's application is deemed withdrawn, the New Facility Operator will compensate the Interconnecting PTO for all reasonable costs incurred to that date in processing the Completed Application.

The Interconnecting PTO will use due diligence to complete the Facility Study within 60 calendar days of receipt of payment and the Facility Study Agreement or initiation of the ISO ADR Procedures. If the Interconnecting PTO cannot complete the Facility Study within 60 calendar days, the Interconnecting PTO will notify the New Facility Operator, in writing, of the reason why additional time is required to complete the required study and the estimated completion date.

A New Facility Operator shall be entitled to amend its Completed Interconnection Application once without losing its queue position. Such amendment shall occur on or before 10 Business Days following the Date the Interconnecting PTO tenders a Facility Study Agreement. Specifically, as an alternative to executing and returning a Facility Study Agreement, a New Facility Operator may submit an amendment to its Completed Interconnection Application to reflect a revised configuration for its New Facility. The amended Completed Interconnection Application shall be treated in accordance with Section 5.7.4.2.1 and the New Facility Operator's Completed Interconnection Application shall not be deemed withdrawn, and it shall maintain its exiting queue position, if (a) the amended Completed Interconnection Application is received by the Interconnecting PTO within 10 Business Days of the Interconnecting PTO's tender of a Facility Study Agreement; and (b) the New Facility Operator has not submitted a previous

amendment to the Completed Interconnection Application. In the event a New Facility Operator amends its Completed Interconnection Application, it will be responsible for any additional study costs that result from that amendment, including costs associated with revisions to studies for other applicants holding later queue positions.

5.7.4.3 Execution of Interconnection Agreement.

Within 10 Business Days of receipt of a completed Facility Study, a New Facility Operator shall request the Interconnecting PTO to provide to such applicant an Interconnection Agreement. The Interconnecting PTO shall provide an Interconnection Agreement to an applicant within 30 Business Days of receipt of the request for an Interconnection Agreement. If the ISO and Interconnecting PTO determine, pursuant to Sections 5.7.4.2.1 and 5.7.4.2.2, that either:

(a) a New Facility Operator's Interconnection Application can be accommodated and that such New Facility Operator will not incur costs for Reliability Upgrades, the New Facility Operator shall execute the Interconnection Agreement within 10 Business Days of receipt of the Interconnection Agreement; or

(b) a New Facility Operator's Interconnection Application will necessitate Reliability Upgrades, the New Facility Operator shall execute the Interconnection Agreement within 30 Business Days of receipt of the Interconnection Agreement or, if a New Facility Operator and the Interconnecting PTO are unable to agree on the rates, terms and conditions of the Interconnection Agreement, the New Facility Operator may request that the Interconnecting PTO file an unexecuted Interconnection Agreement at FERC. If a New Facility Operator does request that the Interconnecting PTO file an unexecuted Interconnection Agreement at FERC, the New Facility Operator shall agree to abide by the rates, terms and conditions of such Interconnection Agreement ultimately determined by FERC to be just and reasonable.

5.7.4.4 Queuing.

(a) The ISO and Interconnecting PTO will process all Interconnection Applications based on the New Facility's Completed Application Date.

(b) The queue position for each New Facility that has submitted an Interconnection Application will be established according to the Completed Application Date and the New Facility's compliance with the milestones set forth in Section 5.7.4.4.1.

(c) For any New Facility Operator that has submitted a request to interconnect to a Interconnecting PTO prior to the date that FERC makes Section 5.7 effective, such New Facility Operator's position in the queue will be based on its Completed Application Date as that term was defined in the Interconnecting PTOs TO Tariff in effect at the time the New Facility Operator submitted a request to interconnect to the Interconnecting PTO.

5.7.4.4.1 Queuing Milestones.

(a) To maintain its queue position, each New Facility Operator must timely comply with the requirements of the ISO Tariff and the TO Tariff of the Interconnecting PTO and must, within 6 months of its Completed Application Date, satisfy all applicable Data Adequacy Requirements of state and local siting and other regulatory authorities. Any New Facility Operator not subject to state siting requirements must satisfy the information requirements set forth in 18 C.F.R. § 2.20. The ISO will permit a New Facility Operator to retain its queue position if such New Facility Operator requests an extension of the six-month period at least 5 Business Days prior to the expiration of such period. Such extension will be limited to one period of 30 Business Days and additional extensions shall not be granted. A New Facility Operator that does not maintain its queue position, but later satisfies the Data Adequacy Requirements, or the requirements of 18 C.F.R. § 2.20 if applicable, will be placed in a queue position comparable to that of other New Facility Operators that have satisfied the Data Adequacy Requirements, or the

5.7.6 Energization.

Neither the ISO nor the Interconnecting PTO shall be obligated to energize, nor shall the New Facility Operator be entitled to have its interconnection to the ISO Controlled Grid energized, unless and until an Interconnection Agreement has been executed, or filed at FERC pursuant to Section 5.7.4.3, and becomes effective and such New Facility Operator has demonstrated to the ISO's reasonable satisfaction that it has complied with all of the requirements of this Section 5.7.

5.8 Recordkeeping; Information Sharing.

5.8.1 Requirements for Maintaining Records.

Participating Generators shall provide to the ISO such information and maintain such records as are reasonably required by the ISO to plan the efficient use and maintain the reliability of the ISO Controlled Grid.

5.8.2 Providing Information to Generators.

The ISO shall provide to any Participating Generator, upon its request, copies of any operational assessments, studies or reports prepared by or for the ISO (unless such assessments studies or reports are subject to confidentiality rights or any rule of law that prohibits disclosure) concerning the operations of such Participating Generator's

inspector to perform such testing as is necessary (i) to test the accuracy of any meters upon which the Participating Generator's compensation is based, or performance is measured, (ii) to test the Participating Generator's compliance with any performance standards pursuant to Section 5.4 of this ISO Tariff, or (iii) to obtain information relative to a Forced Outage.

5.10 Black Start Services.

5.10.1 All Participating Generators with Black Start Generating Units must satisfy technical requirements specified by the ISO.

5.10.2 The ISO shall from time to time undertake performance tests, with or without prior notification.

5.10.3 The ISO shall have the sole right to determine when the operation of Black Start Generating Units is required to respond to conditions on the ISO Controlled Grid.

5.10.4 If the ISO has intervened in the market for Energy and/or Ancillary Services pursuant to Section 2.3.2.3, the price paid by the ISO for Black Start services shall be sufficient to permit the relevant Participating Generator to recover its costs over the period that it is directed to operate by the ISO.

5.10.5 If a Black Start Generating Unit fails to achieve a Black Start when called upon by the ISO, or fails to pass a performance test administered by the ISO, the Market Participant that has contracted to supply Black Start service from the Generating Unit shall re-pay to the ISO any reserve payment(s) that it has received since the administration of the last performance test or the last occasion upon which it successfully achieved a Black Start when called upon by the ISO, whichever is the shorter period.

5.11 Must-Offer Obligations

5.11.1 Applicability

The requirements of Section 5.11 shall apply to (a) all Participating Generators, and (b) all persons, regardless of whether the person is a "public utility" as defined in Section 201 of the Federal Power Act, that own or control one or more non-hydroelectric Generating Units, System Units or System Resources located in California from which energy or capacity is either: (i) sold through any market operated by the ISO, or (ii) transmitted over the ISO Controlled Grid. Each person described in this Section 5.11.1 is referred to in the ISO Tariff as a "Must-Offer Generator." The requirements of this Section 5.11 shall apply to all non-hydroelectric Generating Units located in California that are owned or controlled by a Must-Offer Generator.

5.11.2 Available Generation

For the purposes of this Section 5.11, a Must-Offer Generator's "Available Generation" from a non-hydroelectric Generating Unit shall be: (a) the Generating Unit's maximum operating level adjusted for any outages or reductions in capacity reported to the ISO in accordance with Section 2.3 or 5.11.3 and for any limitations on the Generating Unit's operation under applicable law, including contractual obligations, which shall be reported to the ISO, (b) minus the Generating Unit's scheduled operating point as identified in the ISO's Final Hour-Ahead Schedule, (c) minus the Generating Unit's capacity committed to provide Ancillary Services to the ISO either through the ISO's Ancillary Services market or through self-provision by a Scheduling Coordinator, and (d) minus the capacity of the Generating Unit committed to deliver Energy or provide Operating Reserve to the Must-Offer Generator's Native Load.

5.11.3 Reporting Requirements for Non-Participating Generators

So that the ISO may determine the Available Generation of all Must-Offer Generators, Must-Offer Generators that are not Participating Generators shall be required to file with the ISO, for

If a Must-Offer Generator fails to submit a Supplemental Energy bid for any portion of its Available Generation for any Dispatch Interval, the unbid quantity of the Must-Offer Generator's Available Generation will be deemed by the ISO to be bid at the Must-Offer Generator's Proxy Price for that hour if: (i) the applicable Generating Unit is a gas-fired unit and (ii) the Must-Offer Generator has provided the ISO with adequate data in compliance with Sections 2.5.23.3.3 and 5.11.3 for the applicable Generating Unit. For all other Generating Units owned or controlled by a Must-Offer Generator, the unbid quantity of the Must-Offer Generator's Available Generation will be deemed by the ISO to be bid and settled in accordance with Section 11.2. In order to dispatch resources providing Imbalance Energy in proper merit order, the ISO will insert this unbid quantity into the Must-Offer Generator's Supplemental Energy bid curve above any lower-priced segments of the bid curve and below any higher-priced segments of the bid curve as necessary to maintain a non-decreasing bid curve over the entire range of the Must-Offer Generator's Available Generation.

5.11.6 Waiver of Must-Offer Obligation

Must-Offer Generators may seek a waiver of the obligation to offer all available capacity, as set forth in Section 5.11.4 of this ISO Tariff, for one or more of their Generating Units for periods other than Self-Commitment Periods, which are defined as the hours when Must-Offer Generators submit Energy Schedules or are awarded Ancillary Services bids or self-provision schedules. Self-Commitment Periods determined from Day-Ahead Schedules shall be extended by the ISO as necessary to accommodate Generating Unit minimum up and down times such that the scheduled operation is feasible.

All other Must-Offer Generators obligated under the must-offer obligation will be deemed to have requested a waiver, either implicitly or explicitly, of the obligation to offer all available capacity. If conditions permit, and at the ISO's non-discriminatory and sole discretion, the ISO may grant waivers and allow a Must-Offer Generator to remove one or more Generating Units from service during

hours outside Self-Commitment Periods. The ISO shall grant waivers so as to: 1) provide sufficient on-line generating capacity to meet Operating Reserve requirements; and 2) account for other physical operating constraints, including Generating Unit minimum up and down times. The hours outside of Self-Commitment Periods for which waivers are not granted shall constitute Waiver Denial Periods. The Waiver Denial Period shall be extended as necessary to accommodate Generating Unit minimum up and down times. Units shall be on-line in real time during both Self-Commitment and Waiver Denial Periods, or they will be in violation of the must-offer obligation. Exceptions shall be allowed for verified forced outages. The must-offer obligation will remain in effect for a unit's Self-Commitment Period even if the Must-Offer Generator nullifies its Day-Ahead Schedules for Energy or buys back its Day-Ahead Schedules for a unit in the Hour-Ahead Market. The ISO may revoke waivers as necessary due to outages, changes in Load forecasts, or changes in system conditions. The ISO shall determine which waiver(s) will be revoked, and shall notify the relevant Scheduling Coordinator(s). The ISO shall inform a Must-Offer Generator that its Waiver request has been accepted, denied, or revoked, and shall provide the Must-Offer Generator with the reason(s) for the decision, which reasons shall be non-discriminatory. The ISO will: (1) notify Must-Offer Generators of the ISO decisions on pending Waiver requests received no later than 6:00 p.m. (beginning of Hour Ending 19) no later than 8:00 p.m. (beginning of Hour Ending 21) on the day before the operating day for which the Waivers are requested; (2) at any time but no later than 8:00 p.m. on the following day, notify Must-Offer Generators of the ISO decisions on Waiver requests that were submitted to the ISO after 6:00 p.m. (beginning of Hour Ending 19) on the day before; (3) end Waiver Denial Periods at any time; and (4) revoke Waivers at any time, while making best attempts to revoke a Waiver at least 90 minutes prior to time a unit would be required to be on-line generating at its Pmin.

5.11.6.1 Recovery of Minimum Load Costs By Must-Offer Generators

5.11.6.1.1 Eligibility

Units from Must-Offer Generators that incur Minimum Load Costs during Self-Commitment Periods or during hours for which the ISO has granted to them a waiver shall not be eligible to recover such costs for such hours. When a Must-Offer Generator is awarded Ancillary Services in the Hour-Ahead Market or has a Final Hour-Ahead Schedule other than a Schedule to a unit-specific Demand ID used for the purpose of scheduling minimum load energy as set forth in Section 5.11.6, the Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. When, on a 10-minute Settlement Interval basis, a Must-Offer Generator generating at minimum load in compliance with the must-offer obligation, produces a quantity of Energy that varies by more than the Tolerance Band, the Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such Settlement Intervals during hours within a Waiver Denial Period. When, on a Settlement Interval basis, a Must-Offer Generator's resource produces a quantity of Energy above minimum load due to an ISO Dispatch Instruction, the Must-Offer Generator shall recover its Minimum Load Costs and its bid costs, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band. Subject to the foregoing eligibility restrictions set forth in this section, the ISO shall guarantee recovery of the Minimum Load Costs of an otherwise eligible Must-Offer Generator for each Settlement Interval during hours within a Waiver Denial Period as follows: (1) First, ISO will pre-dispatch for real time the minimum load Energy from Must-Offer Generators that have been denied waivers for each hour within a Waiver Denial Period; (2) This minimum load Energy will be accounted as Instructed

Imbalance Energy for each Settlement Interval within the relevant hour and be settled at the Resource-Specific Settlement Interval Ex Post Price; (3) To the extent the Instructed Imbalance Energy payments are not sufficient to cover the generator's Minimum Load Cost for the hour as defined in Section 5.11.6.1.2 of this Tariff, the generator will also receive an uplift payment for its Minimum Load Cost compensation for the relevant eligible Settlement Intervals of hours during the Waiver Denial Period that the Generating Unit runs at minimum load in compliance with the must-offer obligation; and (4) To the extent the Generator is dispatched for real time Imbalance Energy above its minimum load for any Dispatch Interval within an hour during the Waiver Denial Period, the Generator will be eligible for Bid Cost Recovery, as set forth in Section 11.2.4.1.1.1.

5.11.6.1.2 Minimum Load Costs

The Minimum Load Costs shall be calculated as the sum, for all eligible hours in the Waiver Denial Period and Settlement Periods in which the unit generated in response to an ISO Dispatch Instruction, of: 1) the product of the unit's average heat rate (as determined by the ISO from the data provided in accordance with Section 2.5.23.3.3) at the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC and the proxy figure for natural gas costs posted in the ISO Home Page in effect at the time and the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC; and 2) the product of the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC; and $6.00/MWh.

5.11.6.1.3 Invoicing Minimum Load Costs

The ISO shall determine each Scheduling Coordinator's Minimum Load Costs and make payments for these costs as part of the ISO's market settlement process. Scheduling Coordinators may

submit to the ISO data detailing the hours for which they are eligible to recover Minimum Load Costs. Scheduling Coordinators who elect to submit data on hours they are eligible to recover Minimum Load Costs must: 1) use the Minimum Load Cost invoice template posted on the ISO Home Page, and 2) submit the invoice on or before fifteen (15) Business Days following the last Trading Day in the month in which such costs were incurred, except that Scheduling Coordinators seeking reimbursement for Minimum Load Costs incurred between May 29, 2001, and June 30, 2002 must submit their data to the ISO by August 5, 2002.

5.11.6.1.4 Allocation of Minimum Load Costs

Minimum Load Costs for the total number of eligible hours for each unit shall be evenly divided over all such eligible hours. For each such hour, the total Minimum Load Costs shall be allocated to each Scheduling Coordinator in proportion to the sum of that Scheduling Coordinator's Load and Demand within California outside the ISO Control Area that is served by exports to the sum of the ISO Control Area Gross Load and the projected Demand within California outside the ISO Control Area that is served by exports from the ISO Control Area of all Scheduling Coordinators.

5.11.6.1.5 Payment Of Available Capacity Under The Must-Offer Obligation

Available capacity that is required to be offered to the Real Time Market, if dispatched by the ISO, shall be settled as follows: the actual amount of the dispatched Energy shall be settled at the applicable Instructed Imbalance Energy Market Clearing Price. Minimum Load Cost compensation shall be paid for all otherwise eligible hours within the Waiver Denial Period, as defined in Section 5.11.6.1.1, that the unit generated above minimum load in compliance with ISO Dispatch Instructions.

5.12 [Not Used]

5.13 Energy Bids.

5.13.1 Energy Bid Definition.

A single Energy Bid curve per resource per hour shall be used in: (a) the real-time Hourly Pre-Dispatch as set forth in Dispatch Protocol 8.6.3, and (b) Dispatch in the Real Time Markets. A corresponding operational ramp rate as provided for in SBP Section 6.5 shall be submitted along with the single Energy Bid curve and shall be used in determination of Dispatch Instructions pursuant to Section 2.5.22.6.1(c).

The Energy Bid shall be a staircase price ($/MWh) versus quantity (MW) curve of up to 10 segments. The Energy Bid shall be submitted to the real-time Imbalance Energy market using the Supplemental Energy Bid template. The Energy Bid curve shall be monotonically increasing, i.e., the price of a subsequent segment shall be greater than the price of a previous segment. Subject to the foregoing, sellers may increase or decrease bids in the ISO Real Time Market for capacity associated with those parts of the bid curve that were not accepted in or before the Hour-Ahead Market. For capacity associated with those parts of the bid curve previously accepted in or before the Hour-Ahead Market, sellers may only submit lower bids in subsequent markets. Each Forbidden Operating Region must be represented by only one bid segment.

5.13.2 Energy Bid Submission.

5.13.2.1 Real Time Market. Bids shall be submitted for use in the real-time Hourly Pre-Dispatch in DP 8.6.3(j) and the Real-Time Economic Dispatch up to sixty (60) minutes prior to the Operating Hour. Resources required to offer their Available Generation in accordance with Section 5.11.4 shall be required to submit Energy Bids for 1) all of their Available Generation and 2) any Ancillary Services capacity awarded or self-provided in the Day-Ahead or Hour-Ahead Ancillary Services markets. In the absence of submitted bids, default bids will be used for resources required to offer their Available Generation in accordance with Section 5.11.4. Resources not required to offer their Available Generation in accordance with Section 5.11.4 that were awarded or self-provided Ancillary Services capacity must submit an Energy Bid for no less than the amount of awarded or self-provided Ancillary Services capacity. Resources not required to offer their Available Generation in accordance with Section 5.11.4 may voluntarily submit Energy Bids. Submitted Energy Bids shall be subject to the Damage Control Bid Cap as set forth in Section 28.1 and to the Mitigation Measures set forth in Appendix A to the Market Monitoring and Information Protocol.

5.13.2.2 Real-Time Energy Bid Partition. The portion of the single Energy Bid that corresponds to the high end of the resource's operating range, shall be allocated to any awarded or self-provided Ancillary Services in the following order from higher to lower capacity: (a) Regulation Up; (b) Spinning Reserve; (c) Non-Spinning Reserve; and (d) Replacement Reserve. For resources providing Regulation Up, the upper regulating limit shall be used if it is lower than the highest operating limit. The remaining portion of the Energy Bid (i.e. that portion not associated with capacity committed to provide Ancillary Services) shall constitute a Bid to provide Supplemental Energy.

5.13.3 Requirement to Submit Energy Bids For Awarded or Self-Provided Ancillary Services Capacity

Scheduling Coordinators for resources that have been awarded or self-provide Regulation Up, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity must submit a Supplemental Energy bid for at least all the awarded or self-provided Ancillary Services capacity. To the extent a Supplemental Energy bid is not so submitted for a gas-fired resource, the ISO shall calculate a Supplemental Energy bid in accordance with Section 2.5.23.3.4 and insert that bid into the real-time Imbalance Energy market. To the extent a Supplemental Energy bid is not so submitted for a non-gas-fired resource, the ISO shall insert a bid of $0/MWh into the real-time Imbalance Energy market.

(d) Inter-Zonal Congestion price per Congested path; Total Regulation and Reserve service capacity reservation cost by Zone;

(e) Total capacity of Inter-Zonal Interfaces; and

(f) Available capacity of Inter-Zonal Interfaces.

6.1.2.2.3 Ex Post Information:

(a) Date;

(b) Hour; and

(c) Hourly Ex Post Price.

6.1.2.3 WEnet shall be used by the ISO to post Usage Charges for Inter-Zonal Interfaces within the ISO Controlled Grid.

6.1.2.4 WEnet shall serve as a bulletin board to enable Market Participants to inform one another of scheduling changes and trades made.

6.1.2.5 WEnet may be used by the ISO to communicate operating orders to the Scheduling Coordinators and other Market Participants, both in advance of actual operation and in real time. Such orders may include but are not limited to:

(a) Notifying Scheduling Coordinators and other Market Participants to be on call to provide Non-Spinning Reserve and Replacement Reserves and Black Start;

(b) Issuing start-up instructions;

(c) Stating the amount of Spinning Reserves to be carried;

(d) Requesting specific Ramping patterns;

(e) Indicating which Scheduling Coordinators and other Market Participants are to provide Regulation;

(f) Specifying the minimum amount of unloaded capacity that must be maintained in order to meet Regulation Requirements;

(g) Issuing shut-down instructions; and

(h) Specifying the voltage level and reactive reserve each Market Participant must maintain.

6.1.2.6 WEnet shall be used by the ISO to provide information to Market Participants regarding the ISO Controlled Grid. Such information may include but is not limited to:

(a) Voltage control parameters;

(b) ISO historical data for Congestion;

(c) Forecasts of Usage Charges; and

(d) Generation Meter Multipliers to support seven (7) day advance submission of Schedules by Scheduling Coordinators. Additional Generation Meter Multipliers may be published for different seasons and loading patterns.

6.2 Reliable Operation of the WEnet.

6.2.1 Market Participants shall arrange access to WEnet through the Internet Service Provider.

6.2.2 The ISO shall arrange for the Internet Service Provider to provide a pathway for public Internet connectivity through the WEnet backbone to accommodate users other than Market Participants without the need for a separate, dedicated user data link. This public Internet connection may provide a reduced level of data exchange and reduced information concerning

7.1.6.2 Addition of New Facilities After ISO Implementation. The costs of transmission facilities placed in service after the ISO Operations Date shall be recovered consistent with the cost recovery determinations made pursuant to Section 3.2.7.

7.1.6.3 Effect on Tax-Exempt Status. Nothing in this Section shall compel any Participating TO to violate any restrictions applicable to facilities financed with tax-exempt bonds or contractual restrictions and covenants regarding the use of transmission facilities.

7.2 Zonal Congestion Management.

7.2.1 The ISO Will Perform Congestion Management.

7.2.1.1 Transmission Congestion. Congestion occurs when there is insufficient transfer capacity to simultaneously implement all of the Preferred Schedules that Scheduling Coordinators submit to the ISO.

7.2.1.2 Zone-Based Approach. The ISO will use a Zone-based approach to manage Congestion. A Zone is a portion of the ISO Controlled Grid within which Congestion is expected to occur infrequently or have relatively low Congestion Management costs. Inter-Zonal Interfaces consist of transmission facilities that are expected to have relatively high Congestion Management costs. For these interfaces, allocation of usage based on the value placed on these interfaces by the Scheduling Coordinators will increase efficient use of the ISO Controlled Grid.

7.2.1.3 Types of Congestion. Congestion that occurs on Inter-Zonal Interfaces is referred to as "Inter-Zonal Congestion." Congestion that occurs due to transmission system Constraints within a Zone is referred to as "Intra-Zonal Congestion."

7.2.1.4 Elimination of Potential Transmission Congestion. The ISO's Day-Ahead and Hour-Ahead scheduling procedures will eliminate potential Inter-Zonal Congestion by:

7.2.1.4.1 scheduling the use of Inter-Zonal Interfaces by the Scheduling Coordinators who place the highest value on those rights, based on the Adjustment Bids that are submitted by Scheduling Coordinators; and

7.2.1.4.2 rescheduling Scheduling Coordinators' resources (but so that Intra-Zonal transmission limits are not violated) using the Adjustment Bids that are submitted by Scheduling Coordinators.

7.2.1.5 Elimination of Real-Time Inter-Zonal Congestion. In its management of Inter-Zonal Congestion in real time, the ISO will issue Dispatch Instructions as necessary to relieve Inter-Zonal Congestion by Dispatching Generation or Demand, as necessary, based on the Energy Bids in accordance with Dispatch Protocol Section 8.3.

7.2.2 General Requirements for the ISO's Congestion Management. The ISO's Congestion Management in the Day-Ahead Market and Hour-Ahead Market shall:

7.2.2.1 only operate if the Scheduling Coordinators do not eliminate Congestion voluntarily;

7.2.2.2 adjust the Schedules submitted by Scheduling Coordinators only as necessary to alleviate Congestion;

7.2.2.3 maintain separation between the resource portfolios of different Scheduling Coordinators, by not arranging any trades between Scheduling Coordinators as part of the Inter-Zonal Congestion Management process;

7.2.4.1.2 The Adjustment Bids will be used by the ISO to determine the marginal value associated with each Congested Inter-Zonal Interface.

7.2.4.1.3 [Not used]

7.2.4.1.4 The ISO shall use Energy Bids from Generating Units and from other resources in the ISO's real-time system operation, for increasing resources' output for Intra-Zonal Congestion Management to decrement Generation in order to accommodate Overgeneration conditions, including Reliability Must-Run Generation which the ISO requests under Reliability Must-Run Contracts.

7.2.4.1.5 To facilitate trades amongst Scheduling Coordinators, the ISO will develop procedures to publish Adjustment Bids of those Scheduling Coordinators who authorize the publication of their identity and/or Adjustment Bids. Scheduling Coordinators will then be able to utilize this information to conduct trades to aid Congestion Management.

7.2.4.2 Submission of Adjustment Bids.

7.2.4.2.1 Each Scheduling Coordinator is required to submit a preferred operating point for each of its resources. However, a Scheduling Coordinator is not required to submit an Adjustment Bid for a resource.

7.2.4.2.2 The minimum MW output level specified for a resource, which may be zero MW, and the maximum MW output level specified for a resource must be physically realizable by the resource.

7.2.4.2.3 The Scheduling Coordinator's preferred operating point for each resource must be within the range of the Adjustment Bids.

7.2.4.2.4 Adjustment Bids can be revised by Scheduling Coordinators after the Day-Ahead Market has closed for consideration in the Hour-Ahead Market and, after the Hour-

Ahead Market has closed, for consideration in the Real Time Market provided that, if the ISO has accepted all, or a portion of, an offered Adjustment Bid, the Scheduling Coordinator is obligated to provide the relevant capacity increase or decrease to the ISO at the price of the accepted Adjustment Bid.

7.2.4.2.5 During the ISO's Day-Ahead scheduling process, the MW range of the Adjustment Bid, but not the price values, may be changed.

7.2.4.2.6 An Adjustment Bid shall constitute a standing offer to the ISO until it is withdrawn.

7.2.4.2.7 The ISO may impose additional restrictions and bidding activity rules on the form of Adjustment Bids, the updating of Adjustment Bids, and the Scheduling Coordinator that may submit Adjustment Bids in connection with inter-Scheduling Coordinator trades, as needed, to ensure that the ISO's computational algorithms can operate reliably and produce efficient outcomes.

7.2.5 Inter-Zonal Congestion Management.

7.2.5.1 The scheduling procedures in the Day-Ahead Market and Hour-Ahead Market will first ascertain, through power flow calculations, whether or not Inter-Zonal Congestion would exist if all of the Preferred and Revised Schedules submitted by the Scheduling Coordinators were accepted by the ISO. If no Inter-Zonal Congestion would exist, then all Inter-Zonal Interface uses will be accepted and the Usage Charges will be zero.

7.2.5.2 The purpose of Inter-Zonal Congestion Management is to allocate the use of, and determine the marginal value of, active Inter-Zonal Interfaces. Inter-Zonal Congestion Management will comply with the requirements stated in Sections 7.2.2, 7.2.4 and 7.2.5.

7.2.5.2.1 Inter-Zonal Congestion Management will keep each Scheduling Coordinator's portfolio of Generation and Demand (i.e., the Scheduling Coordinator's Preferred Schedule) separate from the portfolios of the other Scheduling Coordinators, as the ISO adjusts the Schedules to alleviate Inter-Zonal Congestion.

7.2.5.2.2 If Congestion would exist on one or more active Inter-Zonal Interfaces, then the ISO shall execute its Inter-Zonal Congestion Management algorithms to determine a set of tentative (in the Day-Ahead procedure) allocations of Inter-Zonal Interface rights and tentative (in the Day-Ahead procedure) Usage Charges, where the Usage Charges will be calculated as the marginal values of the Congested Inter-Zonal Interfaces. The marginal value of a Congested Inter-Zonal Interface is calculated by the ISO's computer optimization algorithm to equal the total change in Redispatch costs (based on the Adjustment Bids) that would result if the interface's scheduling limit was increased by a small increment.

7.2.5.2.3 As part of the Day-Ahead scheduling procedure, but not the Hour-Ahead scheduling procedure, Scheduling Coordinators will be given the opportunity to adjust their Preferred Schedules (including the opportunity to make trades amongst one another) and to submit Revised Schedules to the ISO, in response to the ISO's Suggested Adjusted Schedules and prices for Inter-Zonal Interfaces.

7.2.5.2.4 If the ISO receives any Revised Schedules it will execute its Inter-Zonal Congestion Management algorithms using revised Preferred Schedules, to produce a new set of allocations and prices.

7.2.5.2.5 All of the ISO's calculations will treat each Settlement Period independently of the other Settlement Periods in the Trading Day.

7.2.5.2.6 [Not Used]

7.2.5.2.7 If inadequate Adjustment Bids have been submitted to schedule Inter-Zonal Interface capacity on an economic basis and to the extent that scheduling decisions cannot be made on the basis of economic value, the ISO will allocate the available Inter-Zonal Interface capacity to Scheduling Coordinators in proportion to their respective proposed use of that capacity as indicated in their Schedules and shall curtail scheduled Generation and Demand to the extent necessary to ensure that each Scheduling Coordinator's Schedule remains balanced.

7.2.5.2.8 The ISO will publish information prior to the Day-Ahead Market, between the iterations of the Day-Ahead Market, and prior to the Hour-Ahead Market, to assist the Scheduling Coordinators to construct their Adjustment Bids so as to actively participate in the management of Congestion and the valuation of Inter-Zonal Interfaces. This information may include the ISO's most-current information regarding: potentially Congested paths, projected transmission uses, projected hourly Loop Flows across Inter-Zonal Interfaces, scheduled line Outages, forecasts of expected system-wide Load, the ISO's Ancillary Services requirements, Generation Meter Multipliers, and power flow outputs.

7.2.5.2.9 The ISO will also publish information, once it is available, regarding tentative prices for the use of Inter-Zonal Interfaces, and Generation shift factors for the use of Inter-Zonal Interfaces, which indicate the relative effectiveness of Generation shifts in alleviating Congestion.

7.2.6 Intra-Zonal Congestion Management.

7.2.6.1 Decremental Bids. With regard to decremental bids, if Final Hour-Ahead Schedules cause Congestion on the Intra-Zonal interface, the ISO shall, after Dispatching available and effective Reliability Must-Run Units to manage the Congestion, apply the decremental reference prices determined by the independent entity that determines the reference prices for the Automatic Mitigation Procedure (AMP) as described in Appendix A to the Market Monitoring and Information Protocol. The ISO shall Dispatch Generating Units

according to the decremental reference prices thus established, the resource's effectiveness on the Congestion, and other relevant factors such as Energy limitations, existing contractual restrictions, and Regulatory Must-Run or Regulatory Must-Take status, to alleviate the Congestion after Final Hour-Ahead Schedules are issued. Where the ISO must reduce a Generating Unit's output, the ISO shall Dispatch Generating Units according to the decremental reference prices and not according to Adjustment Bids or Supplemental Energy Bids to alleviate Intra-Zonal Congestion. No Generating Unit shall be Dispatched below its minimum operating level or above its maximum operating level. No Reliability Must-Run Unit shall be Dispatched below the operating level determined by the ISO as necessary to maintain reliability. If Congestion still exists after all Generating Units are Dispatched to their minimum operating levels, the ISO shall instruct Generating Units to shut off in merit order based on their decremental reference prices at minimum load, beginning with the most expensive unit.

The ISO shall apply the decremental reference prices to thermal Generating Units and to non-thermal Generating Units.

If the ISO Dispatches System Resources or Dispatchable Loads to alleviate Intra-Zonal Congestion, the ISO shall Dispatch those resources in merit order according to the resource's Day-Ahead or Hour-Ahead Adjustment Bid or Imbalance Energy bid.

The ISO shall only Redispatch Regulatory Must-Take or Regulatory Must-Run Generation, Intermittent Resources, or Qualifying Facilities to manage Intra-Zonal Congestion after Redispatching all other available and effective generating resources, including Reliability Must-Run Units.

7.2.6.1.1 Decremental Bid Reference Levels. Decremental bid reference levels shall be determined for use in managing Intra-Zonal Congestion as set forth above in Section 7.2.6.1.

(a) Determination. Decremental bid reference levels shall be determined by applying the following steps in order as needed:

1. Excluding proxy bids, mitigated bids, and bids used out of merit order for managing Intra-Zonal Congestion, the accepted decremental bid, or the lower of the mean or the median of a resource's accepted decremental bids if such a resource has more than one accepted decremental bid in competitive periods over the previous 90 days for peak and off-peak periods, adjusted for monthly changes in fuel prices using the proxy figure for natural gas prices posted on the ISO Home Page. Accepted and justified decremental bids below the applicable soft cap, as set forth in Section 28.1.3 of this Tariff, will be included in the calculation of reference prices;
2. A level determined in consultation with the Market Participant submitting the bid or bids at issue, provided such consultation has occurred prior to the occurrence of the conduct being examined by the ISO, and provided the Market Participant has provided sufficient data in accordance with specifications provided by the ISO or the independent entity responsible for determining reference prices;
3. 90 percent of the unit's default Energy Bid determined monthly as set forth in Section 5.11.5 (based on the incremental heat rate submitted to the ISO, adjusted for gas prices, and the variable O&M cost on file with the ISO, or the default O&M cost of $6/MWh);
4. 90 percent of the mean of the economic Market Clearing Prices for the units' relevant location (Zone or node commensurate with the pricing granularity in effect) during the lowest-priced 25 percent of the hours that

7.2.6.1.3 [Not Used]

7.2.6.1.4 [Not Used]

7.2.6.1.5 [Not Used]

7.2.6.1.6 [Not Used]

7.2.6.2 Incremental Bids. With regard to incremental bids, except as provided in Sections 5.2, 7.2.6.1 and 11.2.4.2, the ISO will perform Intra-Zonal Congestion Management in real time using available Imbalance Energy bids, based on their effectiveness and in merit order, to minimize the cost of alleviating Congestion. In the event no Imbalance Energy bids are available, the ISO will exercise its authority to direct the Redispatch of resources as allowed under the Tariff, including Section 2.4.4.

7.2.6.3 Cost of Intra-Zonal Congestion Management. The net of the amounts paid by the ISO to the Scheduling Coordinators and the amounts charged to the Scheduling Coordinators will be calculated and charged to all Scheduling Coordinators through a Grid Operations Charge, as described in Section 7.3.2.

7.2.7 Creation, Modification and Elimination of Zones.

7.2.7.1 Active Zones. The Active Zones are as set forth in Appendix I to this ISO Tariff.

7.2.7.2 Modifying Zones. The ISO shall monitor usage of the ISO Controlled Grid to determine whether new Zones should be created, or whether existing Zones should be eliminated, in accordance with the following procedures.

7.2.7.2.1 If over a 12-month period, the ISO finds that within a Zone the cost to alleviate the Congestion on a path is equivalent to at least 5 percent of the product of the rated capacity of the path and the weighted average High Voltage Access Charge and Low

submitted and accepted after the ISO's Day-Ahead scheduling and Congestion Management have concluded.

7.3.1.3 Default Usage Charge. If inadequate or unusable Adjustment Bids have been submitted to the ISO to enable the ISO's Congestion Management to schedule Inter-Zonal Interface capacity on an economic basis, then the ISO will calculate and impose a default Usage Charge, in accordance with Sections 7.3.1.3.1 through 7.3.1.3.4.

7.3.1.3.1 The default Usage Charge will be calculated within a range having an absolute floor of $0/MWh and an absolute ceiling of $500/MWh; provided that the ISO may vary the floor within the absolute limits, with day-prior notice (e.g., applicable to next day's Day-Ahead Market) to Scheduling Coordinators, and vary the ceiling within the absolute limits, with at least seven (7) days notice to Scheduling Coordinators.

7.3.1.3.2 The default Usage Charge will be calculated, in accordance with this Section 7.3.1.3, by applying a pre-set adder, ranging from $0/MWh to $99/MWh, to the highest incremental Adjustment Bid used, less the applicable decremental Adjustment Bid used; provided that in all cases where there are insufficient decremental Adjustment Bids or no decremental Adjustment Bids available, in the exercise of mitigating Congestion, the applicable decremental price will be set equal to $0/MWh; provided, further, that the ISO may vary the pre-set adder with day-prior notice to Scheduling Coordinators (*e.g.*, applicable to next day's Day-Ahead Market).

7.3.1.3.3 Upon the ISO Operations Date, and until such time as the ISO determines otherwise, the ceiling price for the default Usage Charge will be set at $250/MWh; the floor price for the default Usage Charge will be set at $30/MWh; and the pre-set adder that is to be applied in accordance with Section 7.3.1.3.2 will be set at $0/MWh.

Charge for each hour they have counter-scheduled on the Congested Inter-Zonal Interfaces. The amount payable shall be the product of the Usage Charge referred to in Section 7.3.1.2 for that particular hour, multiplied by the Scheduling Coordinator's scheduled flows.

7.3.1.5.2 If a Scheduling Coordinator fails to provide the scheduled flows in a counter direction, it must reimburse the ISO for the ISO's costs of buying or selling Imbalance Energy in each of the Zones affected by the non-provided scheduled flows in a counter direction, at the ISO's Zonal Imbalance Energy prices. That is, for any Scheduling Coordinator that does not produce, in real time, the amount of Energy scheduled in the Day-Ahead Market or Hour-Ahead Market will be deemed to have purchased/sold the amount of Energy under/over produced in the real-time imbalance market at the real-time price.

7.3.1.5.3 Scheduling Coordinators shall not receive a Usage Charge payment for scheduled flows in a counter direction if such scheduled flow is the result of a Circular Schedule.

7.3.1.6 ISO Disbursement of Net Usage Charge Revenues. The ISO will determine the net Usage Charges on an interface-by-interface basis by subtracting the Usage Charge fees paid to Scheduling Coordinators from the Usage Charge fees paid by Scheduling Coordinators. The net Usage Charge revenues collected by the ISO for each Inter-Zonal Interface shall be, subject to the provisions of Section 7.3.1.7 of the ISO Tariff, paid to: (i) FTR Holders, in accordance with Section 9.6; and (ii) to the extent not paid to FTR Holders, to Participating TOs who own the Inter-Zonal Interfaces and Project Sponsors as provided in Section 3.2.7.3. Participating TOs will credit in turn the Usage Charge revenue to their Transmission Revenue Balancing Accounts, or, for those Participating TOs that do not have such accounts, to their Transmission Revenue Requirements.

7.3.1.7 ISO Debit of Net Usage Charge Revenues. If, after the issuance of Final Day-Ahead Schedules by the ISO, (a) Participating TOs instruct the ISO to reduce interface limits based on operating conditions or (b) an unscheduled transmission Outage occurs and as a result of either of those events, Congestion is increased and Available Transfer

Capacity is decreased in the Inter-Zonal Interface in the Hour-Ahead Market, the ISO shall: (1) charge each Participating TO and Project Sponsor(s) as provided in Section 3.2.7.3, and FTR Holder with an amount equal to its proportionate share, based on its financial entitlement to Usage Charges in the Day-Ahead Market in accordance with Section 7.3.1.6, of the product of (i) the Usage Charge in the Day-Ahead Market and (ii) the reduction in Available Transfer Capacity across the Inter-Zonal Interface in the direction of the Congestion (such amount due to the Participating TOs to be debited by them in turn from their Transmission Revenue Balancing Accounts or, for those Participating TOs that do not have such accounts, to their Transmission Revenue Requirements); (2) charge each Scheduling Coordinator with its proportionate share, based on Schedules in the Day-Ahead Market across the Inter-Zonal Interface in the direction of the Congestion, of the difference between the amount charged to Participating TOs and Project Sponsors as provided in Section 3.2.7.3, and FTR Holders under clause (1) and the Usage Charges in the Hour-Ahead Market associated with the reduced Available Transfer Capacity across the Congested Inter-Zonal Interface; and (3) credit each Scheduling Coordinator whose Schedule in the Hour-Ahead Market for the transfer of Energy across the Congested Inter-Zonal Interface was adjusted due to the reduction in Available Transfer Capacity an amount equal to the product of the adjustment (in MW) and the Usage Charge in the Hour-Ahead Market (in$/MW).

The ISO will issue a notice to Scheduling Coordinators of the operating hour, and extent, for which the derate will apply in the relevant Hour-Ahead Markets. The timing and form of such notices shall be set forth in ISO procedures.

7.3.2 Grid Operations Charge for Intra-Zonal Congestion.

Scheduling Coordinators whose resources are Redispatched by the ISO, in accordance with Intra-Zonal Congestion Management as set forth in Section 7.2.6, will be paid or charged as set forth in Settlements and Billing Protocol Appendix B. The net

Redispatch cost will be recovered for each Settlement Period through the Grid Operations Charge, which shall be paid to the ISO by all Scheduling Coordinators in proportion to their metered Demands within the Zone with Intra-Zonal Congestion, and scheduled exports from the Zone with Intra-Zonal Congestion to a neighboring Control Area, provided that, with respect to Demands within an MSS in the Zone and scheduled exports from the MSS to a neighboring Control Area, a Scheduling Coordinator shall be required to pay Grid Operations Charges only with respect to Intra-Zonal Congestion, if any, that occurs on an interconnection between the MSS and the ISO Controlled Grid, and with respect to Intra-Zonal Congestion that occurs within the MSS, to the extent the Congestion is not relieved by the MSS Operator.

7.4 Transmission Losses.

7.4.1 Obligation to Provide for Transmission Losses.

Each Scheduling Coordinator shall ensure that it schedules sufficient Generation to meet both its Demand and Transmission Losses responsibilities as determined in accordance with this Section 7.4. Scheduling Coordinators for Generators, System Units and System Resources are responsible for their respective proportion of Transmission Losses as determined in accordance with Section 7.4.2. For each Final Hour-Ahead Schedule, each Scheduling Coordinator representing Generators or System Units shall elect through the flag described in SBP Section 2.1.1 to either: 1) generate sufficient additional energy to meet its respective Transmission Losses or 2) be financially responsible for its respective transmission loss obligation based on the Imbalance Energy procured on its behalf by the ISO. In the ISO Imbalance Energy market, all Scheduling Coordinators for Generators, System Units, and System Resources must be financially responsible for all respective Transmission Losses associated with their respective Imbalance Energy Dispatch Instructions in real time, based on the Imbalance Energy procured on their behalf by the ISO. A Scheduling Coordinator for an MSS Operator that has elected

Controlled Grid at the same electrical bus shall be assigned the same Ex Post Generation Meter Multiplier.

7.4.2.1 Procedures for Calculating Generation Meter Multiplier.

7.4.2.1.1 By 6:00 p.m. two days preceding a Trading Day, the ISO will calculate, and post on WEnet, an estimated Generation Meter Multiplier for each electrical bus at which one or more Generating Units may supply Energy to the ISO Controlled Grid. The Generation Meter Multipliers shall be determined utilizing the Power Flow Model based upon the ISO's forecasts of total Demand for the ISO Controlled Grid and Demand and Generation patterns throughout the ISO Controlled Grid. The ISO shall continuously update the data to be used in calculating the Generation Meter Multipliers to reflect changes in system conditions on the ISO Controlled Grid, and the ISO shall provide all Scheduling Coordinators with access to such data. The ISO shall not be required to determine new Generation Meter Multipliers for each hour; the ISO will determine the appropriate period for which each set of Generation Meter Multipliers will apply, which period may vary based upon the expected frequency and magnitude of changes in system conditions on the ISO Controlled Grid.

7.4.2.1.2 The ISO will calculate the Ex Post Generation Meter Multiplier for each electrical bus at which one or more Generating Units may supply Energy to the ISO Controlled Grid. The Ex Post Generation Meter Multipliers shall be determined utilizing the Power Flow Model based upon the ISO's total Demand for the ISO Controlled Grid and Demand and Generation patterns throughout the ISO Controlled Grid. The ISO's total Demand shall be determined using real-time power flow data based on a state-estimation result.

8.3.1 Core Reliability Services Charge.

The Core Reliability Services Charge for a Scheduling Coordinator is calculated using the Scheduling Coordinator's metered non-coincident peak hourly Demand during the month (in megawatts). The rate for the Core Reliability Services Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total of the forecasted metered non-coincident peak hourly Demand for all months during the year, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.2 Energy Transmission Services Net Energy Charge.

The Energy Transmission Services Net Energy Charge for each Scheduling Coordinator is calculated using that Scheduling Coordinator's Metered Control Area Load (in megawatt-hours). The rate for the Energy Transmission Services Net Energy Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted Metered Control Area Load, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.3 Energy Transmission Services Uninstructed Deviations Charge.

The Energy Transmission Services Uninstructed Deviations Charge for each Scheduling Coordinator is calculated using that Scheduling Coordinator's net uninstructed deviations by Settlement Interval. The rate for the Energy Transmission Services Uninstructed Deviations Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted net

uninstructed deviations by Settlement Interval according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.4 Forward Scheduling Charge.

The Forward Scheduling Charge for each Scheduling Coordinator is calculated using the sum of that Scheduling Coordinator's Final Hour-Ahead Schedules, including all awarded Ancillary Services bids, with a value other than 0 MW, submitted to the scheduling infrastructure/scheduling application system. The rate for the Forward Scheduling Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted Final Hour-Ahead Schedules and awarded Ancillary Service bids submitted to the ISO, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.5 Congestion Management Charge.

The Congestion Management Charge for each Scheduling Coordinator is calculated as the product of the rate for the Congestion Management Charge and the absolute value of the net scheduled inter-zonal flow (excluding flows pursuant to Existing Contracts) per path for that Scheduling Coordinator. The rate for the Congestion Management Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted inter-zonal scheduled flow (excluding flows pursuant to Existing Contracts) per path in MWh, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.6 Market Usage Charge.

The Market Usage Charge for each Scheduling Coordinator is calculated using the absolute value of the Scheduling Coordinator's market purchases and sales of Ancillary Services, Supplemental Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with uninstructed deviations being netted by Settlement Interval). The rate for the Market Usage Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted number of market purchases and sales, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.7 Settlements, Metering, and Client Relations Charge.

The Settlements, Metering, and Client Relations Charge for each Scheduling Coordinator is fixed at $500.00 per month, per Scheduling Coordinator ID with an invoice value other than $0.00 in the current trade month, as indicated in Appendix F, Schedule 1, Part A of this Tariff. Excess GMC costs related to the provision of these services that are not recovered through this charge are allocated to the other GMC service categories as specified above and in Appendix F, Schedule 1, Part E of this Tariff.

8.4 Calculation and Adjustment of the Grid Management Charge.

The seven charges set forth in Section 8.3 that comprise the Grid Management Charge shall be calculated through the formula set forth in Appendix F, Schedule 1, Part A of this Tariff. The formula set forth in Appendix F, Schedule 1, Part C of this Tariff sums the Operating Costs (less any available expense recoveries), Financing Costs, and Operating and Capital Reserves Costs associated with each of the seven ISO service charges to obtain a total revenue requirement. This revenue requirement is allocated among the seven charges of the GMC through the application of the factors specified in Appendix F, Schedule 1, Part E of this Tariff.

accordance with Schedule 3 to Appendix F. Amounts payable by Original Participating TOs under this section shall be recoverable as part of the Transition Charge calculated in accordance with Schedule 3 of Appendix F. Amounts received by the ISO under this section shall be disbursed to New Participating TOs with Existing High Voltage Facilities based on the ratio of each New Participating TO's net increase in costs in the categories described in the first sentence of this section, to the sum of the net increases in such costs for all New Participating TOs with Existing High Voltage Facilities.

9. FIRM TRANSMISSION RIGHTS

9.1 General

9.1.1 Commencing in 2000, on the effective date established by the ISO Governing Board, the ISO shall make FTRs available in the amounts determined in accordance with Section 9.3, with the rights and other characteristics described in Sections 9.2, 9.6, 9.7 and 9.8, and through the processes described in Section 9.4. Proceeds of the ISO's auction of FTRs shall be distributed as described in Section 9.5. The owners of FTRs shall be entitled to share in Usage Charge revenues associated with Inter-Zonal Congestion in accordance with Section 9.6, and to scheduling priority in the event of Congestion in the Day-Ahead Market, as described in Section 9.7. For the purpose of Section 9, the term "Zone" shall be construed to mean both "Zone" and "Scheduling Point."

9.2 Characteristics of Firm Transmission Rights

9.2.1 Each FTR shall be defined by a transmission path from an originating Zone to a contiguous receiving Zone. Each FTR shall entitle the FTR Holder to a share of Usage Charges attributable to Inter-Zonal Congestion for transfers on that path from the designated originating Zone to the designated receiving Zone in accordance with Section 9.6. An FTR is a right in one direction only. An FTR Holder shall not be entitled to share in (i) Usage Charges attributable to Inter-Zonal Congestion from the designated receiving Zone to the designated

(i) The WECC approved path rating of the interface in the direction from the originating Zone to the receiving Zone or, if the interface has not received a WECC approved rating, a rating determined by a methodology that is consistent with the WECC's rating methodology; and

(ii) The portion of the transfer capability of the interface available for transmission scheduling under Existing Contracts as Existing Rights.

and ensures the ISO's ability to honor all of its FTRs simultaneously under normal operating conditions.

9.4 Issuance of Firm Transmission Rights by the ISO

9.4.1 The ISO shall make FTRs available by conducting an annual primary auction of FTRs, commencing approximately two months before the beginning of the term of the FTRs; provided; however that for the initial FTR release, the primary auction shall be as determined by the ISO Governing Board. The auction of FTRs shall be a simultaneous multi-round, clearing price auction conducted separately and independently, as set forth in Section 9.4.2, for each FTR Market. In addition, if the ISO Governing Board decides to make available, between annual auctions, FTRs in addition to those that were purchased in the last annual auction, the ISO may conduct additional auctions of such FTRs in accordance with Section 9.4.2. The term of such FTRs shall only be for the remaining duration of the FTR term defined for the primary auction applicable to the year during which they were issued.

9.4.2 The ISO shall conduct the auction of FTRs through the following procedures:

9.4.2.1 At least thirty (30) days prior to the scheduled start of the auction, the ISO shall post on the ISO Home Page the following information:

(iv) the date and time prior to the commencement of the auction by which each entity desiring to bid on FTRs must have satisfied the necessary financial requirements as outlined in Section 9.2.6;

(v) the specifications for the technical equipment necessary to participate in the auction, which will be conducted electronically, the date and time by which bids must be submitted in the first round of the auction, which shall be the same for all FTR Markets, and the form and format in which bids must be submitted; and

(vi) a schedule for the conduct of subsequent rounds of the auction, including the interval between rounds of the auction and the anticipated duration of the auction.

9.4.2.2 On or before the date specified in Section 9.4.2.1(v), any entity desiring to obtain FTRs in the ISO's auction must submit, via equipment satisfying the technical requirements specified in accordance with Section 9.4.2.1(v), a bid for each FTR Market in which the entity desires to participate, specifying the number of FTRs the entity is willing to purchase at the price specified in Section 9.4.2.1(ii). All individual bids will remain confidential throughout all rounds of the auction in each FTR Market. Once submitted to the ISO, a bid for FTRs in any round of an auction may not be cancelled or rescinded by the FTR Bidder. The ISO shall announce simultaneously to all FTR Bidders the total quantity of FTRs for which valid bids are submitted for each FTR Market.

9.4.2.3 In each round of the auction following the first round, the ISO will increase the price at which FTRs are made available in each FTR Market in accordance with the formula posted in accordance with Section 9.4.2.1(iii), or in accordance with any adjustment to the coefficients in that formula that is announced by the ISO to the FTR Bidders at least one round in advance of the round for which the adjustment is made. Price increases need not be uniform for all FTR Markets.

In the case of an FTR Market in which the demand for FTRs in the preceding round is less than or equal to the quantity of FTRs being made available, the price shall not increase and the auction for that FTR Market shall close. After each round of the auction, the ISO shall announce simultaneously to all FTR Bidders the total quantity of FTRs for which valid bids were submitted in each FTR Market, whether the auction for each FTR Market is closed, and, the revised prices for the following round of the auctions that remain open. Within the timeframe set by the ISO in accordance with Section 9.4.2.1(vi), each FTR Bidder may submit bids for the quantity of FTRs it desires to purchase in each FTR Market at the revised price, provided that an FTR Bidder may not bid for a number of FTRs in an FTR Market that exceeds the total number of FTRs in that FTR Market for which that entity submitted bids in the preceding round of the auction. The ISO shall conduct subsequent rounds of the auction in each FTR Market until the demand for FTRs in the FTR Market is less than or equal to the quantity of FTRs being made available, at which point the auction shall be closed in that FTR Market.

9.4.2.4 Subject to Section 9.4.2.5, each successful FTR Bidder shall receive a number of FTRs in each FTR Market equal to the number of FTRs for which it bid in the last round of the auction for that FTR Market.

9.4.2.5 For any FTR Market in which, when the auction has closed, the number of FTRs being made available exceeds the demand for FTRs in that FTR Market in the last round of the auction, each FTR Bidder shall be awarded a number of FTRs determined in accordance with the following formula, provided that, if the number of FTRs that would be awarded under the formula to an FTR Bidder that did not submit a bid in the last round of the auction is less than five percent (5%) of the initial bid submitted by that FTR Bidder for the FTR Market, that FTR Bidder shall have the option of declining the award of FTRs resulting from the formula:

FTR Market in the first round of the auction was less than the quantity of FTRs being made available for that FTR Market, the price of FTRs in that FTR Market shall be the first round price and each FTR Bidder in that FTR Market will receive a number of FTRs equal to the quantity of bids they submitted in the first round. Any remaining FTRs in that FTR Market will not be awarded in that auction.

9.4.2.7 Each FTR Bidder shall pay the ISO an amount equal to the sum, for all FTR Markets, of the products of the FTR price in each FTR Market (determined in accordance with Section 9.4.2.6) and the total quantity of FTRs awarded to that FTR Bidder in that FTR Market (determined in accordance with Section 9.4.2.4 or Section 9.4.2.5, as applicable). FTR Bidders shall pay the amount determined in accordance with the foregoing sentence within ten (10) Business Days of receiving an invoice from the ISO by making payment to the ISO Clearing Account in accordance with Section 11.10. If the FTR Bidder fails to make timely payment of the full amount due, the ISO may enforce any guarantee, letter of credit or other credit support provided by the defaulting FTR Bidder in accordance with Section 9.2.6 and, if the ISO is required to institute proceedings to collect any unpaid amount, the defaulting FTR Bidder shall pay Interest on the unpaid amount for the period from the Payment Date until the date on which payment is remitted to the ISO Clearing Account.

9.4.2.8 The ISO shall post on the ISO Home Page the prices at which FTRs are sold in each FTR Market through the primary auction.

9.4.3 For the ten-year transition period described in Section 4 of Schedule 3 to Appendix F, a New Participating TO that has an obligation to serve Load shall receive FTRs for Inter-Zonal Interfaces to which the transmission facilities and Converted Rights for Inter-Zonal Interfaces that the New Participating TO turns over to the ISO's Operational Control give it transmission rights. The amount of FTRs will be determined when the Transmission Control Agreement is executed and shall be commensurate with the

Ahead Market for the transfer of 1 MW from the originating Zone to the receiving Zone during each hour in which Usage Charges apply, multiplied by the number of FTRs owned by that FTR Holder, subject to adjustment in accordance with Section 9.6.3.

9.6.2 In addition, an FTR Holder shall be entitled to receive a portion of the additional net Usage Charges related to Inter-Zonal Congestion calculated by the ISO in the Hour-Ahead Market and collected by the ISO with respect to the Inter-Zonal Interface and direction combination for which the FTR was defined. The FTR Holder shall receive a portion of the net Usage Charges in the Hour-Ahead Market proportionate to the share of the Usage Charges it received in the Day-Ahead Market in accordance with Section 9.6.1.

9.6.3 When the Day-Ahead scheduling capability of an Inter-Zonal Interface and direction is less than its scheduling capacity, determined in accordance with Section 9.3, prior to the Day-Ahead Market, the entitlements of FTR Holders associated with that FTR Market to Usage Charge revenues shall not be reduced until and unless the entitlements of Participating TOs associated with that FTR Market to Usage Charge revenues in accordance with Section 7.3.1.6 have been reduced to zero. In that event, the financial entitlements associated with the corresponding FTRs shall be multiplied by a factor equal to the amount of scheduling capability available to holders of the remaining FTRs divided by the number of such FTRs. When the Day-Ahead scheduling capability of an Inter-Zonal Interface and direction is greater than its scheduling capacity, determined in accordance with Section 9.3, prior to the Day-Ahead Market, the entitlements of FTR Holders associated with that FTR Market to Usage Charge revenues shall not be increased.

9.6.4 When the Congestion Usage Charges calculated and collected by the ISO from the Hour-Ahead Market with respect to transfers across an Inter-Zonal Interface in a particular direction result in a net obligation to the ISO, in the circumstances described in Section 7.3.1.7, the

provisions of this Section 9.6 shall continue to apply, and FTR Holders shall be required to pay the ISO these amounts.

9.6.5 The ISO will calculate the Congestion Usage Charge revenues to be credited or debited to the account of each FTR Holder on an hourly basis. Such calculation will identify the Inter-Zonal Interface and direction to which each credit or debit applies.

9.7 Scheduling Priority of FTR Holders

9.7.1 FTRs will not affect the ISO's dispatch and operation of the ISO Controlled Grid except that each FTR Holder will have a priority, as described in this Section 9.7, for the scheduling of Energy in the Day-Ahead Market when an Inter-Zonal Interface experiences Inter-Zonal Congestion in the direction for which its FTR is defined. Any FTRs not used in Preferred Schedules in the Day-Ahead Market for any hour have no scheduling priority for that hour in the Trading Day. FTR Holders shall have no scheduling priority in the Hour-Ahead Market or in real-time operations.

9.7.2 When Inter-Zonal Congestion is experienced or projected to be experienced in the Day-Ahead Market, the ISO shall first attempt to relieve the Inter-Zonal Congestion using Adjustment Bids submitted by Scheduling Coordinators in accordance with Section 7.2.4.

9.7.2.1 If the ISO is unable to relieve the Day-Ahead Inter-Zonal Congestion using Adjustment Bids, then the ISO will allocate Day-Ahead inter-zonal transmission capacity first to Schedules of Market Participants that are using Existing Contract rights that have higher scheduling priority than Converted Rights capacity and second to Market Participants who hold FTRs and have indicated to the ISO that they wish to exercise their scheduling priority option. The ISO will allocate any remaining transmission capacity to remaining Market Participants' Schedules pro rata.

9.7.3 When the scheduling capability of an Inter-Zonal Interface is less than or greater than its normal scheduling capability prior to the Day-Ahead Market, as described in Section 9.6.3, the priority scheduling rights of FTR Holders, as described in Section 9.7.2, shall remain constant (in

MWs) to the extent that the total scheduling rights of FTR Holders do not exceed the total Interface scheduling capability of the associated Inter-Zonal Interface after adjustments have been made for transmission capacity allocated to Existing Contract rights that have higher scheduling priority than Converted Rights. If the total Interface scheduling capability, adjusted for transmission capacity allocated to Existing Contract rights that have higher scheduling priority than Converted Rights, is less than the total of all scheduling capability represented by FTR Holders who have chosen to exercise the FTR scheduling priority option, scheduling capability shall be allocated to FTR Holders pro rata.

9.7.4 The scheduling priority of FTR Holders:

(i) Shall not apply in the Hour-Ahead Market or in real-time dispatch and operation of the ISO Controlled Grid;

(ii) Shall not apply to any transfer of Energy other than a transfer across the Inter-Zonal Interface in the direction for which the FTR was defined during the hour or hours during which the circumstances described in Section 9.7.2.1 apply; and

(iii) Shall not be transferable, except in connection with a transfer of the FTR that is registered with the ISO, as described in Section 9.8.

9.8 Assignment of Firm Transmission Rights

9.8.1 An FTR may be assigned, sold, or otherwise transferred by the FTR Holder to any entity eligible to be an FTR Holder in full MW increments, either for the entire term of the FTR or for any portion of that term providing, however, that any such transfer shall be in full hour increments that correspond to the FTR issued to the FTR Holder. All FTRs that are so assigned, sold, or otherwise transferred by the FTR Holder are subject to the terms and conditions for FTRs approved by FERC and set forth in the ISO Tariff. Both the FTR Holder of record and the entity to which the FTRs have been transferred shall register the transfer of the FTR with the ISO by

notifying the ISO through the form specified for that purpose by the ISO, and within the number of Business Days following the transfer published by the ISO on the ISO Home Page and WEnet but no later than such time as the ISO shall specify before the deadline applicable to scheduling Energy in the Day-Ahead Market, of (i) the identity of the FTR Holder of record; (ii) the identity of the entity to which the FTRs have been transferred; (iii) the quantity and identification numbers of the FTRs being transferred; (iv) the portion of the term of the FTR for which they are transferred; (v) the price at which the FTRs are being transferred; and (vi) whether the transfer of FTRs is subject to any conditions. The entity to which the FTRs have been transferred must also notify the ISO of all entities with which the transferee is affiliated that are FTR Holders or Market Participants as defined in the ISO Tariff, pursuant to Section 9.2.7. After the ISO receives such notices, the transferee shall be considered the FTR Holder of record with respect to the portion of the term of the FTR that is transferred. In order to use the Scheduling Priority of an FTR, pursuant to Section 9.7, an FTR must be registered with the ISO.

9.8.2 The ISO shall publish on the ISO Home Page such information concerning the concentration of ownership of FTRs in each FTR Market as determined by the ISO Governing Board from time to time.

9.8.3 To facilitate the operation of secondary markets in FTRs, the ISO shall post on WEnet and the ISO Home Page: (i) the identity of entities that hold FTRs that have been registered with the ISO, together with the quantity of FTRs held by such entities in each FTR Market and the path rating of the interface; and (ii) the name and a contact telephone number or telecopy number of any entity that operates a secondary market in FTRs and that requests the ISO to post such information. The ISO shall also post the prices at which FTRs are transferred through secondary market transactions and shall indicate whether such transfers are conditional.

10. METERING.

10.1 Applicability.

Unless otherwise expressly stated to the contrary, the requirements set forth in these Sections 10.1 to 10.5 inclusive apply only to ISO Metered Entities.

10.2 Responsibilities of ISO Metered Entities

10.2.1 Duty to Provide Meter Data.

ISO Metered Entities shall ensure that Meter Data from their meters directly connected to the ISO Controlled Grid or at interconnections thereto, including interconnections between utility Service Areas which have separate UFE calculations, is made available to the ISO revenue Meter Data acquisition and processing system in accordance with the requirements of these Sections 10.1 to 10.5 and the ISO metering protocols. Pursuant to this obligation, the ISO shall establish revenue metering protocols for such ISO Metered Entities.

10.2.2 Duty to Install and Maintain Meters.

The ISO may require ISO Metered Entities to install, at their cost, additional meters and relevant metering system components, including real-time metering, at ISO specified Meter Points or other locations as deemed necessary by the ISO, in addition to those connected to or existing on the ISO Controlled Grid at the ISO Operations Date, including requiring the metering of transmission interfaces connecting Zones. In directing the addition of meters and metering system components that would impose increased costs on an ISO Metered Entity, the ISO shall give due consideration to whether the expected benefits of such equipment are sufficient to justify such increased costs. ISO Metered Entities, at their cost, shall install and maintain, or cause to be installed and maintained, metering equipment and associated communication devices at ISO designated Meter Points to meet the requirements of this Section 10 and the ISO metering protocols. Nothing in this Section 10 shall preclude ISO Metered Entities from installing additional meters, instrument transformers and associated communications facilities at their own cost.

10.2.3 Metering Standards.

Each ISO Metered Entity shall ensure that each of its meters used to provide Meter Data to the ISO complies with the meter standards and accuracy requirements for meters set forth in Appendix J and the ISO metering protocols.

10.2.4 Certification of Meters.

Each ISO Metered Entity that makes Meter Data available to the ISO shall ensure that metering facilities used to produce such Meter Data have been certified by the ISO as meeting the requirements of these Sections 10.1 to 10.5 and the ISO metering protocols. Certification of the relevant metering facilities shall only be provided upon the production of such evidence as the ISO may reasonably require to demonstrate that the facilities in question have been documented, inspected and successfully tested by the ISO or an ISO Authorized Inspector for conformance to the standards and accuracy requirements referred to in Appendix J and the ISO metering protocols. Meters of End-Use ISO Metered Entities in place as of the ISO Operations Date are deemed to be certified as in compliance with Appendix J and such End-Users shall not be required to enter into meter service agreements with the ISO provided that their Scheduling Coordinators have entered into a meter service agreement with the ISO. ISO certification pursuant to this Section 10.2.4 shall not relieve the ISO Metered Entity from the obligation to ensure that its metering facilities continue to remain in compliance with the requirements of these Sections 10.1 to 10.5 and the ISO metering protocols.

10.2.5 Metering Communications.

The ISO's revenue meter data acquisition and processing system shall collect and process Meter Data made available by ISO Metered Entities pursuant to meter service

agreements. Meter Data for ISO Metered Entities shall be made available to the ISO's revenue meter data acquisition and processing system either directly by the ISO Metered Entity or via a central data server which collects Meter Data for various ISO Metered Entities provided that the central data server does not aggregate or adjust that Meter Data. Meter Data on the ISO's revenue meter data acquisition and processing system may be accessed from the system's database by the ISO Settlement system, other ISO application programs, relevant Scheduling Coordinators and other authorized users as identified in the relevant meter service agreement ("other authorized users") subject to the ISO being satisfied that access by such authorized users will not adversely effect the security of data held by the ISO. ISO Metered Entities shall ensure that their metering facilities are compatible with the ISO revenue meter data acquisition and processing system for these purposes. The ISO may, at its discretion, exempt an ISO Metered Entity from the requirement to make Meter Data directly available to the ISO's revenue meter data acquisition and processing system, for example, where the installation of communication links is unnecessary, impracticable or uneconomic. The ISO shall maintain the revenue meter data acquisition and processing system and remedy any faults occurring in such system. ISO Metered Entities shall ensure compliance with the metering protocols to be established by the ISO pursuant to Section 10.2.1. Scheduling Coordinators and other authorized users requiring Settlement Quality Meter Data for ISO Metered Entities they schedule or supply may obtain such data by polling the revenue meter data acquisition and processing system via WEnet in accordance with the ISO metering protocol. Scheduling Coordinators and other authorized users shall not poll the ISO revenue meter data acquisition and processing system for any other purpose, unless specifically authorized in their meter service agreement. If any Scheduling Coordinator does not have the ability to poll the ISO's revenue meter data acquisition and processing system as at the ISO

include data correction and substitution algorithms which shall estimate, substitute and flag such inaccurate or missing data. Any necessary correction or replacement shall be approved by the ISO prior to the data being sent to the ISO Settlement system. Security and validation measures for existing Tie Point Meters shall be consistent with existing arrangements with the operators in adjacent Control Areas. Any additional measures or changes to the existing arrangements shall only be implemented upon mutual agreement of the ISO and the operator in the adjacent Control Area.

10.3.3 Availability of Meter Data.

The meter service agreement and the ISO metering protocols shall set out the ISO's requirements with regard to the frequency which it requires Meter Data to be made available to the ISO revenue meter data acquisition and processing system.

10.3.4 Failure to Achieve Required Standards.

Meter service agreements shall set out appropriate measures and rights the ISO may exercise upon any failure by the other party to meet the requirements for meter standards and accuracy set out in these Sections 10.1 to 10.5 inclusive.

10.3.5 ISO Imposed Penalties and Sanctions

The ISO shall have the authority to impose penalties and sanctions, including but not limited to suspension of trading rights, if an ISO Metered Entity provides fraudulent metering data to the ISO. Such penalties shall be approved by FERC.

10.4 Low Side Metering.

Generators may, with the prior written approval of the ISO, install meters at the low voltage side of the connecting transformer. Such approval shall be given only if the ISO is satisfied that adequate accuracy and security of Meter Data obtained can be assured.

Settlement Quality Meter Data for Scheduling Coordinator Metered Entities to the ISO. Such agreements shall specify that Scheduling Coordinators require their Scheduling Coordinator Metered Entities to adhere to the meter requirements set forth in this Section 10.6.

10.6.7.2 [Not Used]

10.6.7.3 [Not Used]

10.6.7.4 Approval by Local Regulatory Authority of Security and Validation Procedures. Scheduling Coordinators shall be responsible for obtaining any necessary approval of the relevant Local Regulatory Authority to its proposed security, validation, editing and estimation procedures.

10.6.7.5 UDC and TO Agreements. Each Scheduling Coordinator shall be responsible for obtaining any necessary consent from the UDCs on whose Distribution Systems or the Participating TOs on whose transmission facilities the Scheduling Coordinator has Scheduling Coordinator Metered Entities as is necessary to give effect to the procedures governing Meter Data validation and security and inspection and testing of metering facilities. Scheduling Coordinators must verify with the relevant UDC the identity of each Scheduling Coordinator Metered Entity they represent and must notify the UDC of any discrepancies of which they become aware.

10.6.7.6 [Not Used]

10.6.7.7 Scheduling Coordinator Metered Entity Certification, Testing and Audit. Subject to any Local Regulatory Authority requirements, the ISO reserves the right to inspect, test and otherwise audit the entire metering systems of the Scheduling Coordinator Metered Entity connected to the ISO Controlled Grid, from the Meter Data server to the metering system(s), and such systems shall be subject to ISO audits and

tests. However, only the Meter Data server supplying the ISO is subject to ISO certification requirements.

The Scheduling Coordinator or its designated representative shall provide the ISO with all such information, assistance and cooperation the ISO reasonably requires in order to conduct such inspections, tests and audits.

10.6.7.8 Failure to Achieve Required Standards. Subject to any Local Regulatory Authority requirements, meter service agreements shall set out appropriate measures and rights the ISO may exercise upon any failure by the other party to meet the requirements for meter standards and accuracy set out in this Section 10.6.

10.6.8 Data Access.

Meter Data of a Scheduling Coordinator Metered Entity remains the property of that Scheduling Coordinator Metered Entity and shall be made available to third parties only with its express permission or as otherwise required by law or provided for in this ISO Tariff. The ISO shall be granted access to Meter Data of Scheduling Coordinator Metered Entities obtained by Scheduling Coordinators.

10.6.9 Exemptions from ISO Metering Standards

The ISO has the authority to grant exemptions from certain ISO metering standards for Scheduling Coordinator Metered Entities that are subject to ISO metering standards provided the ISO annually publishes details of the criteria the ISO will use when considering an application for an exemption and details of specific exemptions which are available.

(4) Imbalance Energy charges;

(5) Usage Charges;

(6) High Voltage Access Charges and Transition Charges;

(7) Wheeling Access Charges;

(8) Voltage Support and Black Start charges; and

(9) Reliability Must-Run Charges; and

(10) Default Interest Charges.

11.2 Calculations of Settlements.

The ISO shall calculate, account for and settle the following charges in accordance with this ISO Tariff.

11.2.1 Grid Management Charge.

The Grid Management Charge will be levied in accordance with Section 8 of this ISO Tariff.

11.2.2 Grid Operations Charge.

The Grid Operations Charge will be levied in accordance with Section 7.3.2 of this ISO Tariff.

11.2.3 Ancillary Services

The ISO shall calculate, account for and settle charges and payments for Ancillary Services as set out in Sections 2.5.27.1 to 4, and 2.5.28.1 to 4 of this ISO Tariff.

11.2.4 Imbalance Energy.

The ISO shall calculate, Dispatch and account for Imbalance Energy for each Dispatch Interval and settle Imbalance Energy in the Real Time Market for each Settlement Interval for the relevant Zone or Scheduling Point within the ISO Controlled

Grid. Imbalance Energy is the difference between the Metered Quantity and the Energy that corresponds to the Final Hour-Ahead Schedule. Instructed Imbalance Energy is the portion of Imbalance Energy that is produced or consumed due to Dispatch Instructions. The Instructed Imbalance Energy will be calculated based on all Dispatch Instructions taking into account applicable ramp rates and time delays. All Dispatch Instructions shall be deemed delivered. The remaining Imbalance Energy constitutes Uninstructed Imbalance Energy, and will be calculated based on the difference between the Metered Quantity and the Generator's Dispatched Operating Point.

11.2.4.1 Net Settlements for Uninstructed Imbalance Energy.

Uninstructed Imbalance Energy attributable to each Demand Take-Out Point, Generating Unit, System Unit or System Resource for which a Scheduling Coordinator has a Final Hour-Ahead Schedule or Metered Quantity, for each Settlement Interval, shall be deemed to be sold or purchased, as the case may be, by the ISO and charges or payments for Uninstructed Imbalance Energy shall be settled by debiting or crediting, as the case may be, the Scheduling Coordinator with an amount for each Settlement Interval in accordance with Section 2.5.23.2.1. Positive or negative Uninstructed Imbalance Energy as described in SABP Appendix D, Section 2.1.1 shall be paid or charged the Resource-Specific Settlement Interval Ex Post Price or the Zonal Settlement Interval Ex Post Price, as the case may be.

11.2.4.1.1 Settlement for Instructed Imbalance Energy

Instructed Imbalance Energy attributable to each Scheduling Coordinator in each Settlement Interval shall be deemed to be sold or purchased, as the case may be, by the ISO and charges or payments for Instructed Imbalance Energy shall be settled by debiting or crediting, as the case may be, the Scheduling Coordinator with an amount for each Settlement Interval in accordance with Section 2.5.23.

11.2.4.1.1.1 Bid Cost Recovery for Generating Units, System Units and Curtailable Demand.

The ISO shall determine, for each Trading Day, for each Generating Unit, System Unit and Curtailable Demand, Dispatched in the Real Time Market pursuant to Section 2.5.22, whether there exists a surplus or deficit in that resource's recovery of its Energy Bid costs, that are less than or equal to the Maximum Bid Level, through Instructed Imbalance Energy credits, as set forth in Section 11.2.4.1.1. This determination of market revenue surplus or deficit shall be calculated as the difference between: 1) the Instructed Imbalance Energy payment as based on the

11.2.4.1.1.2 Bid Cost Recovery for System Resources

The ISO shall determine, for each Settlement Period, for each System Resource submitting bids in the Real Time Market pursuant to Section 2.5.22, whether there exists a surplus or deficit in that resource's recovery of its Energy Bid costs. This determination of market revenue surplus or deficit shall be calculated as the difference between: 1) the Instructed Imbalance Energy payment as based on the simple average of the relevant Dispatch Interval Ex Post Prices for each Settlement Period and 2) the resource's Energy Bid cost for each Settlement Period. An uplift payment will be made as necessary for each Settlement Period to assure that the System Resource recovers its Energy Bid costs for the quantity of Energy delivered. Payments for un-recovered bid costs for portions of Energy associated with bids above the Maximum Bid Level are subject to recall if such bids have not been adequately justified pursuant to Section 28.1.2.

11.2.4.1.2 Penalties for Uninstructed Imbalance Energy

The ISO shall charge Scheduling Coordinators Uninstructed Deviation Penalties for Uninstructed Imbalance Energy resulting from resource deviations outside a Tolerance Band from their Dispatch Operating Point, for dispatched resources, or their Final Hour-Ahead Schedule otherwise. The Dispatch Operating Point will take into account the expected Ramping of a resource as it moves to a new Hour-Ahead Schedule at the top of each hour and as it responds to Dispatch Instructions. The Uninstructed Deviation Penalty will be applied as follows:

a) The Uninstructed Deviation Penalty for negative Uninstructed Imbalance Energy will be calculated and assessed in each Settlement Interval. The Uninstructed Deviation Penalty for positive Uninstructed Imbalance Energy will be calculated and assessed in each Settlement Interval in which the ISO has not declared a staged System Emergency;

b) The Uninstructed Deviation Penalty will apply to pre-Dispatched bids from non-dynamically scheduled System Resources identified, when such a pre-Dispatch Instruction is issued more than 40 minutes prior to the relevant Operating Hour, subject to the following conditions: i) The Uninstructed Deviation Penalty will only apply to the pre-Dispatched amount of the bid that is declined or not delivered, ii) the Uninstructed Deviation Penalty will not apply to a portion of a pre-Dispatched bid that is subsequently not delivered at the direction of a Control Area, including the ISO, due to a curtailment of transmission capability or to prevent curtailment of native firm load occurring subsequent to issuing the pre-Dispatch Instruction, iii) the Uninstructed Deviation Penalty will not apply to uninstructed energy resulting from declining subsequent intra-hour Dispatch Instructions. Dynamically scheduled System Resources, to the extent they deviate from their Final Hour-Ahead Schedule plus any real-time Dispatch Instructions, will be subject to the Uninstructed Deviation Penalty;

c) The Uninstructed Deviation Penalty will not apply to Load or Curtailable Demand;

d) [Not Used]

e) The Uninstructed Deviation Penalty will not apply to Regulatory Must-Run Generation or Participating Intermittent Resources that meet the scheduling obligations established in the Eligible Intermittent Resources Protocol. No other applicable charges will be affected by this exemption. The Uninstructed Deviation Penalty also will not apply to Qualifying Facilities (QFs) that have not executed a Participating Generator Agreement (PGA), pending resolution of QF-PGA issues at FERC;

f) For the Scheduling Coordinator of an MSS that has elected to follow the MSS Load and associated Transmission Losses pursuant to Section 23.12, the deviation penalties in Sections 23.12.2.1 and 23.12.2.2 will apply. For the Scheduling Coordinator of an MSS

that has not elected to follow the MSS Load, the Uninstructed Deviation Penalties in this Section 11.2.4.1.2 will apply;

g) The Uninstructed Deviation Penalty will apply to Generating Units providing Regulation and dynamically scheduled System Resources providing Regulation to the extent that uninstructed deviations from such resources exceed each resource's actual Regulation range plus the applicable Tolerance Band. Resources providing Regulation and generating within their relevant Regulating range (or outside their relevant Regulating range as a direct result of ISO control or instruction) will be deemed to have zero deviations for purposes of the Uninstructed Deviation Penalty.

h) The Uninstructed Deviation Penalty will be calculated and assessed for each resource individually, except that as specified in this Section, uninstructed deviations from individual resources may be aggregated. Uninstructed deviations can be aggregated for resources that: 1) are represented by the same Scheduling Coordinator, 2) are connected to the same ISO Controlled Grid bus and voltage level, and 3) are not Reliability Must Run Condition 2 resources. The ISO will consider, on a case-by-case basis, requests to aggregate uninstructed deviations amongst resources represented by the same Scheduling Coordinator based on an ISO review of impact on the ISO Controlled Grid. The ISO may temporarily suspend any aggregation as needed to ensure reliability. The applicable Pmax of aggregated groups of resources will exclude units that are not operating;

i) [Not Used]

j) [Not Used]

k) The Uninstructed Deviation Penalty will not apply when the Zonal Settlement Interval Ex Post Price is negative or zero;

l) The Uninstructed Deviation Penalty for positive Uninstructed Imbalance Energy will be the amount of the Uninstructed Imbalance Energy in excess of the Tolerance Band multiplied by a price equal to 100% of the corresponding Zonal Settlement Interval Ex Post Price. The net effect of the Uninstructed Deviation Penalty and the Settlement for positive Uninstructed Imbalance Energy beyond the Tolerance Band will be that the ISO will not pay for such Energy;

m) The Uninstructed Deviation Penalty for negative Uninstructed Imbalance Energy will be the amount of the Uninstructed Imbalance Energy in excess of the Tolerance Band multiplied by a price equal to 50% of the corresponding Zonal Settlement Interval Ex Post Price;

n) The Uninstructed Deviation Penalty will not apply to deviations from Energy delivered as part of a scheduled test so long as the test has been scheduled by the Scheduling Coordinator with the ISO or the ISO has initiated the test for the purposes of validating unit performance;

o) The Uninstructed Deviation Penalty shall apply to any excess Energy delivered from or any shortfall of Energy not delivered from an out-of-market (OOM) transaction involving a Generating Unit or a System Unit once the ISO and the supplier have agreed upon the time of, duration of, and the amount of Energy to be delivered in the OOM transaction. The Uninstructed Deviation Penalty shall apply to firm OOM transactions with System Resources to the extent the System Resource fails to deliver the agreed-to Energy or over-delivers the agreed-to Energy if that over- or under-delivery was due to action taken by or not taken by the System Resource and not the result of action taken by a Control Area operator due to a curtailment of firm transmission capability or to prevent curtailment of native firm load occurring subsequent to issuing the pre-Dispatch Instruction;

p) Generating Units with Uninstructed Imbalance Energy will be exempted from the Uninstructed Deviation Penalty if the Generating Unit was physically incapable of delivering the expected Energy, provided that the Generating Unit had notified the ISO within 30 minutes of the onset of an event that prevents the resource from performing its obligations. A Generating Unit must notify ISO operations staff of its reasons for failing to deliver the expected Energy in accordance with Section 2.3.3.9.5 and must provide information to the ISO that verifies the reason the resource failed to comply with the Dispatch instruction within 48 hours of the operating hour in which the instruction is issued;

q) Adjustments to any Generating Unit, Curtailable Demand and System Resource Final Hour-Ahead Schedules made in accordance with the terms of Existing Contracts shall not be subject to Uninstructed Deviation Penalties.

r) Any changes made to Schedules prior to the ISO issuing Final Hour-Ahead Schedules shall not be subject to Uninstructed Deviation Penalties.

s) Uninstructed Deviation Penalties shall not be charged to any deviation from a Dispatch Instruction that does not comply with the requirements set forth in the Dispatch Protocol.

Scheduling Coordinator for each Settlement Period for each such resource by application of either of the following payment options described below. For resources subject to a Reliability Must-Run Contract, the ISO will dispatch such resources according to the terms of the RMR Contract. In circumstances where an RMR Unit would be used to resolve Intra-Zonal Congestion and there are no such RMR Units available, a resource may be called upon and paid under this Section to resolve the Intra-Zonal Congestion.

By December 31 of each year for the following calendar year, each Scheduling Coordinator for a resource shall select one of the following payment options for each resource it schedules:

(a) the Uninstructed Imbalance Energy charge price as calculated in accordance with Section 2.5.23.2.2 (i.e., using the Hourly Ex Post Price) or

(b) a calculated price:

(i) for decremental dispatch orders that is an Energy payment to the ISO that is equal to the Market Clearing Price for the relevant Settlement Period for the applicable Energy market less verifiable daily gas imbalance charges, if any, that are solely attributable to the ISO's Dispatch Instruction and that the Scheduling Coordinator or Generator was not able to eliminate or reduce despite the application of best efforts, if the Scheduling Coordinator provides the resource's daily gas imbalance charges to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched; and

(ii) for incremental dispatch orders is the sum of: 1) a capacity payment equal to the average Day-Ahead Market prices for Spinning Reserve and Non-Spinning Reserve for the three (3)

most recent similar days for the same Settlement Period for which the resource is dispatched; 2) an Energy payment equal to the average calculated using the ISO Real Time Market Energy prices for the three (3) most recent similar days for the same Settlement Period for which the resource is dispatched; 3) such resource's verifiable Start-Up Fuel Costs, if the start-up was solely attributable to the ISO's Dispatch Instruction and if the Scheduling Coordinator provides the resource's Start-Up Fuel Costs to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched; and 4) verifiable daily gas imbalance charges, if any, that are solely attributable to the ISO's Dispatch Instruction and that the Scheduling Coordinator or Generator was not able to eliminate or reduce despite the application of best efforts, if the Scheduling Coordinator provides the resource's daily gas imbalance charges to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched. References to "similar days" in this Section refer to Business Days when the resource is dispatched on a Business Day and otherwise to days that are not Business Days.

To the extent a Scheduling Coordinator does not specify a payment option, the ISO will apply the payment provisions of the payment option described in Section 11.2.4.2(a).

11.2.4.2.1 Allocation of Costs Resulting From Dispatch Instructions

Pursuant to Section 11.2.4.1, the ISO may, at its discretion, Dispatch any Participating Generator, Participating Load and dispatchable System Resource that has not bid into the Imbalance Energy or

Ancillary Services markets, to avoid an intervention in market operations or to prevent or relieve a System Emergency. Such Dispatch may result from, among other things, planned and unplanned transmission facility Outages; bid insufficiency in the Ancillary Services and real-time Energy markets; and location-specific requirements of the ISO. The cost associated with each Dispatch instruction is broken into two components:

a) the portion of the Energy payment at or below the Market Clearing Price ("MCP") for the Settlement Interval, and

b) the portion of the Energy payment above the MCP, if any, for the Settlement Interval.

For each Settlement Interval, costs above the MCP incurred by the ISO for such Dispatch instructions necessary as a result of a transmission facility Outage or in order to satisfy a location-specific requirement in that Settlement Interval shall be payable to the ISO by the Participating Transmission Owner in whose Service Area the transmission facility is located or the location-specific requirement arose. The costs incurred by the ISO for such Dispatch instructions for reasons other than for a transmission facility Outage or a location-specific requirement will be recovered in the same way as for Instructed Imbalance Energy.

11.2.4.2.2 Allocation of Above-MCP Costs For Accepted Bids

For each Settlement Interval, the at or below-MCP costs incurred as a result of accepted bids in the ISO Imbalance Energy Markets shall be allocated in accordance with 11.2.4.1. Allocation of above-MCP costs for accepted bids in the ISO Imbalance Energy Markets shall be in accordance with this Section 11.2.4.2.2 as follows.

11.2.4.2.2.1 Allocation of Bid Costs Above the Maximum Bid Level

For each Settlement Interval, costs that are both above the MCP and above the Maximum Bid Level, incurred by the ISO as a result of Instructed Imbalance Energy and Dispatch instructions for reasons other than for a transmission facility Outage or a location-specific requirement shall

be charged to Scheduling Coordinators as follows in a three-step process. First, each Scheduling Coordinator's charge shall be the lesser of:

(a) the pro rata share of the total costs that are both above the MCP and above the Maximum Bid Level based upon the ratio of each Scheduling Coordinator's Net Negative Uninstructed Deviations to the total system Net Negative Uninstructed Deviations; or

(b) the amount obtained by multiplying the Scheduling Coordinator's Net Negative Uninstructed Deviation for each Settlement Interval and a weighted average price. The weighted average price is equal to the total costs that are both above the MCP and above the Maximum Bid Level divided by the MWh delivered as a result of ISO instructions with a cost component above the MCP.

Second, any remaining unallocated costs shall be reduced pursuant to Section 11.2.4.1.2.

Third, any remaining unallocated costs shall be allocated amongst all Scheduling Coordinators in that Settlement Interval pro rata based on their metered Demand, including exports.

A Scheduling Coordinator shall be exempt from the first allocation step of costs that are both above the MCP and above the Maximum Bid Level in a Settlement Interval if the Scheduling Coordinator has sufficient incremental Energy bids from physically available resources in the Imbalance Energy market to cover its Net Negative Uninstructed Deviation in the given Settlement Interval and the prices of such Energy bids do not exceed the applicable Maximum Bid Level as set forth in Section 28.1.2 of this Tariff.

11.2.4.2.2.2 Allocation of Bid Costs Above-MCP and Below the Maximum Bid Level

For each Settlement Interval, the total unrecovered costs pursuant to Section 11.2.4.1.1.1 that are above the MCP and below the Maximum Bid Level for each Trading Day will be allocated pro-rata to each Scheduling Coordinator based on its metered Demand. For a Scheduling Coordinator of an MSS Operator that has elected to follow Load, allocation of such unrecovered costs will be based on net metered Demand.

11.2.4.3 Unaccounted For Energy (UFE)

For settlement purposes, UFE is treated as Imbalance Energy. For each Settlement Interval, the ISO will calculate UFE on the ISO Controlled Grid, for each utility Service Area for which separate UFE calculation is performed. The UFE will be settled as Imbalance Energy at the Zonal Settlement Interval Ex Post Price. UFE attributable to meter measurement errors, load profile errors, Energy theft, and distribution loss deviations will be allocated to each Scheduling Coordinator based on the ratio of their metered Demand (including exports to neighboring Control Areas) within the relevant utility Service Area to total metered Demand within the utility Service Area.

11.2.4.4 High Voltage Access Charges and Transition Charges will be levied in accordance with Section 7.1 of this ISO Tariff and Appendix F, Schedule 3.

11.2.4.5 Participating Intermittent Resources

11.2.4.5.1 Uninstructed Energy and Transmission Losses by Participating Intermittent Resources

Uninstructed Imbalance Energy associated with deviations by a Participating Intermittent Resource and Transmission Losses shall be settled as provided in this Section 11.2.4.5.1 for every Settlement Period in which such Participating Intermittent Resource meets the scheduling requirements established in the ISO Protocols. In each Settlement Period such requirements are met, the Participating Intermittent Resource shall be exempt from the charges (payments) for Uninstructed Imbalance Energy. Instead, the net Uninstructed Imbalance Energy in each Settlement Interval, together with the transmission loss obligation calculated in accordance with Section 7.4.1.1, shall be assigned to a deviation account specific to each Participating Intermittent Resource. The net balance in each deviation account at the end of each calendar month shall be paid (or charged) to the Scheduling Coordinator for the associated Participating Intermittent Resource at the average price specified in Section 2.5.23.2.3 of the ISO Tariff. If the above-referenced scheduling requirements for Participating Intermittent Resources are not met, then charges (payments) for Uninstructed Imbalance Energy during such Settlement Periods shall be determined in accordance with Section 11.2.4.1.

11.2.4.5.2 Adjustment of Other Charges Related to Participating Intermittent Resources

Charges pursuant to Section 2.5.28.4 or Section 11.2.4.2.2 to Scheduling Coordinators representing Participating Intermittent Resources shall exclude the effect of uninstructed deviations by Participating Intermittent Resources that have scheduled in accordance with the ISO Protocols. The amount of such adjustments shall be accumulated and settled as provided in Section 11.2.4.5.3.

11.2.4.5.3 Allocation of Costs From Participating Intermittent Resources

The charges (payments) for Uninstructed Imbalance Energy that would have been calculated if the Settlement Interval deviations by each Participating Intermittent Resource were priced at the appropriate Dispatch Interval Ex Post Price shall be assigned to a monthly balancing account for all Participating Intermittent Resources in the ISO Control Area. The balance in such account at the end of each month shall be netted against the aggregate payments (charges) by Scheduling Coordinators on behalf of Participating Intermittent Resources pursuant to Section 11.2.4.5.1. The resulting balance, together with the adjustments to charges in each Settlement Interval or Settlement Period pursuant to Section 11.2.4.5.2 shall be assigned to each Scheduling Coordinator in the same proportion that such Scheduling Coordinator's aggregate Net Negative Uninstructed Deviations in that month bears to the aggregate Net Negative Uninstructed Deviations for all Scheduling Coordinators in the Control Area in that month.

11.2.4.5.4 Payment of Forecasting Fee

A fee to defray the costs of the implementation of the forecasting service for Participating Intermittent Resources shall be assessed to Scheduling Coordinators for Participating Intermittent Resources as specified in Schedule 4 of Appendix F.

11.2.14 The ISO shall calculate, charge and disburse all collected default Interest in accordance with the ISO Tariff Settlement and Billing Protocol Sections 2, 5, and 6.

11.3 Billing and Payment Process.

11.3.1 The billing and payment process shall be based on the issuance of Preliminary and Final Settlement Statements for each Settlement Period in each Trading Day.

11.3.2 Payment for the charges referred to in Section 11.1.6 of the ISO Tariff (except for the charges payable under long-term contracts) for each Trading Day in each calendar month shall be made five (5) Business Days after issuance of the Preliminary Settlement Statement for the last day of the relevant calendar month. Payment for adjustments will be made five (5) Business Days after issuance of the Final Settlement Statement for the last day of the relevant month. Payments for FERC Annual Charges will be made in accordance with Section 7.5 of this ISO Tariff.

11.3.3 [Not used]

11.3.4 [Not used]

11.4 General Principles for Production of Settlement Statements.

11.4.1 Basis of Settlement. The basis of each Settlement Statement shall be the debiting or crediting of an account in the name of the relevant Scheduling

calculated Meter Data. When actual verified Meter Data is available and all of the disputes raised by Scheduling Coordinators during the validation process described in Section 11.7 of this ISO Tariff have been determined, the ISO shall recalculate the amounts payable and receivable by the affected Scheduling Coordinators or by all Scheduling Coordinators, if applicable, as soon as reasonably practical and shall show any required adjustments as a debit or credit in the next Settlement Statement.

11.6 Settlements Cycle.

11.6.1 Timing of the Settlements Process.

11.6.1.1 The ISO shall provide to each Scheduling Coordinator for validation a Preliminary Settlement Statement of charges payable to or owed by the Scheduling Coordinator within thirty-eight (38) Business Days of the relevant Trading Day, covering all Settlement Periods in that Trading Day.

11.6.1.2 Each Scheduling Coordinator shall have a period of eight (8) Business Days from the issuance of a Preliminary Settlement Statement during which it may review the Preliminary Settlement Statement and notify the ISO of any errors. No later than fifty-one (51) Business Days after the Trading Day to which it relates, the ISO shall issue a Final Settlement Statement to each Scheduling Coordinator for that Trading Day.

11.6.1.3 Each Scheduling Coordinator shall have a period of ten (10) Business Days from the issuance of the Final Settlement Statement during which it may review the Incremental Changes on the Final Settlement Statement and notify the ISO of any errors. No later than twenty-five (25) Business Days from the date of issuance of the Final Settlement Statement, the ISO shall incorporate any required corrections in a subsequent Preliminary Settlement Statement.

11.6.2 Basis for Billing and Payment.

The Preliminary and the Final Settlement Statements shall constitute the basis for billing and associated automatic funds transfers in accordance with this ISO Tariff. The Preliminary Settlement Statement shall constitute the basis for billing and associated automatic funds transfers for all charges in the first instance. The Final Settlement Statement shall constitute the basis for billing and associated automatic funds transfers for adjustments to charges set forth in the Preliminary Settlement Statement. Each Scheduling Coordinator shall pay any net debit and shall be entitled to receive any net credit shown in an invoice on the Payment Date, whether or not there is any dispute regarding the amount of the debit or credit.

11.6.2.1 Elimination of Invoices under $10.00.

Preliminary and final invoices either due to or from any Market Participant for amounts less than $10.00 will be adjusted to $0.00 and no amount will be due to or from that Market Participant for that invoice.

11.6.3 Settlement Statement Re-runs and post final adjustments.

The ISO is authorized to perform Settlement Statement Re-runs following approval of the ISO Governing Board. A request to perform a Settlement Statement Re-run may be made at any time by a Scheduling Coordinator by notice in writing to the ISO Governing Board. The ISO Governing Board shall, in considering whether to approve a request for a Settlement Statement Re-run, determine in its reasonable discretion, whether there is good cause to justify the performance of a Settlement Statement Re-run.

11.6.3.1 If a Settlement Statement Re-run is ordered by the ISO Governing Board, the ISO shall arrange to have the Settlement Statement Re-run carried out as soon as is reasonably practicable following the ISO Governing Board's order, subject to the availability of staff and computer time, compatible software, appropriate data and other resources.

11.6.3.2 The ISO Governing Board may order the cost of a Settlement Statement Re-run to be borne by the Scheduling Coordinator requesting it, unless the Settlement Statement Re-run was needed due to a clerical oversight or error on the part of the ISO staff.

11.6.3.3 Where a Settlement Statement Re-run indicates that the accounts of Scheduling Coordinators should be debited or credited to reflect alterations to Settlements previously made under this ISO Tariff, for those Scheduling Coordinators affected by the statement re-run, the ISO shall reflect the amounts to be debited or credited in the next Preliminary Settlement Statements that it issues following the Settlement Statement Re-run to which the provisions of this Section 11 apply.

11.6.3.4 Reruns, post closing adjustments and the financial outcomes of Dispute Resolution may be invoiced separately from monthly market activities. The ISO shall provide a market notice at least 30 days prior to such invoicing identifying the components of such invoice.

11.7 Confirmation and Validation.

11.7.1 Confirmation.

It is the responsibility of each Scheduling Coordinator to notify the ISO if it fails to receive a Preliminary Settlement Statement or a Final Settlement Statement on the date specified for the publication of such Settlement Statement in the ISO Payments Calendar. Each Scheduling Coordinator shall be deemed to have received its Settlement Statement on the dates specified, unless it notifies the ISO to the contrary.

11.7.2 Validation.

Each Scheduling Coordinator shall have the opportunity to review the terms of the Preliminary Settlement Statements that it receives. The Scheduling Coordinator shall be deemed to have validated each Preliminary Settlement Statement unless it has raised a dispute or reported an exception within eight (8) Business Days from the date of issuance. Once validated, a Preliminary Settlement Statement shall be binding on the Scheduling

(a) the accurate, time-sequenced, end-to-end traceability of the Settlements process so that Scheduling Coordinators and Participating TOs can fully verify their Settlement Statements;

(b) the ability to specify and accept data that is specifically needed for audit trail requirements; and

(c) the archiving of Meter Data, Settlement runs and other information used to prepare Settlement Statements to be consistent with the time frame required to re-run the Settlement process by state laws and the rules of the Local Regulatory Authority.

11.21.2 Data Dissemination.

Data shall not be disseminated by the ISO except as permitted in this ISO Tariff.

11.22 Confidentiality.

The ISO shall implement and maintain a system of communications with Scheduling Coordinators that includes the strict use of passwords for access to data to ensure compliance with Section 20.3.

11.23 Communications.

Preliminary Settlement Statements, Final Settlement Statements and invoices will be considered issued to ISO Creditors or ISO Debtors when released by the ISO via direct computer link. If there is a failure of a communication system and it is not possible to communicate by electronic means, then the ISO or ISO Creditor or ISO Debtor, as the case may be, shall communicate by facsimile but only if the recipient is first advised by telephone to expect the facsimile.

date to mediate the dispute. Matters discussed during the mediation shall be confidential and shall not be referred to in any subsequent proceeding. With the consent of all disputing parties, a resolution may include referring the dispute directly to a technical body (such as a WECC technical advisory panel) for resolution or an advisory opinion, or referring the dispute directly to FERC. The ISO shall publish notice of the referral of the dispute in the ISO newsletter or WEnet, and any other method adopted by the ISO ADR Committee.

13.2.5 Demand for Arbitration.

If the disputing parties have not succeeded in negotiating a resolution of the dispute within thirty (30) days of the initial statement of claim or, if within that period the parties agreed to mediate, within thirty (30) days of the parties first meeting with the mediator, such parties shall be deemed to be at impasse and any such disputing party may then commence the arbitration process, unless the parties by mutual agreement agree to extend the time. A party seeking arbitration shall provide notice of its demand for arbitration to the other disputing parties, the ISO ADR Committee and the ISO Governing Board, which shall publish notice of such demand in the ISO newsletter or electronic bulletin board, and any other method adopted by the ISO ADR Committee.

13.3 Arbitration.

13.3.1 Selection of Arbitrator.

13.3.1.1 Disputes Under $1,000,000. Where the total amount of claims and counterclaims in controversy is less than $1,000,000 (exclusive of costs and interest), the disputing parties shall select an arbitrator from a list containing the names of at least 10 qualified individuals supplied by the ISO ADR Committee, or if the ISO is a party to the dispute, the names of at least ten (10) qualified individuals supplied by the American

which case the ISO shall give Market Participants as much notice as is reasonably practicable. Any notices issued under this provision shall be delivered in accordance with the procedures set out in Section 20.1 of this ISO Tariff and, in the case of the ISO Protocols, Section 16.2 of this ISO Tariff.

20.2 Waiver.

Any waiver at any time by the ISO or any Market Participant of its rights with respect to any default under this ISO Tariff, or with respect to any other matter arising in connection with this ISO Tariff, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this ISO Tariff. Any delay short of the statutory period of limitations in asserting or enforcing any right shall not constitute or be deemed a waiver.

20.3 Confidentiality.

20.3.1 ISO

The ISO shall maintain the confidentiality of all of the documents, data and information provided to it by any Market Participant that are treated as confidential or commercially sensitive under Section 20.3.2; provided, however, that the ISO need not keep confidential: (1) information that is explicitly subject to data exchange through WEnet pursuant to Section 6 of this ISO Tariff; (2) information that the ISO or the Market Participant providing the information is required to disclose pursuant to this ISO Tariff, or applicable regulatory requirements (provided that the ISO shall comply with any applicable limits on such disclosure); or (3) information that becomes available to the public on a non-confidential basis (other than as a result of the ISO's breach of this ISO Tariff).

20.3.2 Confidential Information

The following information provided to the ISO by Scheduling Coordinators shall be treated by the ISO as confidential:

(a) individual bids for Supplemental Energy;

(b) individual Adjustment Bids for Congestion Management which are not designated by the Scheduling Coordinator as available;

(c) individual bids for Ancillary Services;

(d) transactions between Scheduling Coordinators;

(e) individual Generator Outage programs unless a Generator makes a change to its Generator Outage program which causes Congestion in the short term (i.e. one month or less), in which case, the ISO may publish the identity of that Generator.

20.3.3 Other Parties

No Market Participant shall have the right hereunder to receive from the ISO or to review any documents, data or other information of another Market Participant to the extent such documents, data or information is to be treated as in accordance with Section 20.3.2; provided, however, a Market Participant may receive and review any composite documents, data, and other information that may be developed based upon such confidential documents, data, or information, if the composite document does not disclose such confidential data or information relating to an individual Market Participant and provided, however, that the ISO may disclose information as provided for in its bylaws.

Departmental Secretary to take such steps as are necessary to give effect to any provisions of this Tariff that are not enforceable against the federal entity.

(c) To the extent that the ISO suffers any loss as a result of being unable to enforce any indemnity as a result of such enforcement being in violation of federal laws or regulations to which it is entitled under the Tariff under this Section or otherwise, it shall be entitled to recover such loss through the Grid Management Charge.

21. GENERATION METER MULTIPLIERS.

21.1 Temporary Simplification Relating to GMM Loss Factors.

Notwithstanding any other provision in the ISO Tariff, including the ISO Protocols, in determining whether a Schedule is a Balanced Schedule, no allowance shall be made for Transmission Losses (i.e. the Generation Meter Multiplier shall be set at 1.0) for all Scheduling Coordinators.

21.2 Application.

Notwithstanding any other provision in this Tariff, including the ISO Protocols, the temporary simplification measure specified in this Section 21 shall have effect until discontinued by a Notice of Full-Scale Operations issued by the Chief Executive Officer of the ISO.

21.2.1 Pursuant to Subsections 21.3.1 and 21.3.2, the Chief Executive Officer of the ISO shall give notice to all Scheduling Coordinators that such Scheduling Coordinators shall use forecasted Generation Meter Multipliers, as published by the ISO, in their Schedules. Such notice shall be given only after the Chief Executive Officer determines that the ISO is capable of accepting Schedules using the forecasted Generation Meter Multipliers without adversely affecting operations or reliability.

21.2.2 [Not used]

21.3 Notices of Full-Scale Operations.

21.3.1 When the Chief Executive Officer of the ISO determines that the ISO is capable of implementing this Tariff, including the ISO Protocols, without modification in accordance with a temporary simplification measure specified in this Section 21, he shall issue a notice ("Notice of Full-Scale Operations") and shall specify the relevant temporary simplification measure and the date on which it will permanently cease to apply, which date shall be not less than seven (7) days after the Notice of Full-Scale Operations is issued.

21.3.2 A Notice of Full-Scale Operations shall be issued when it is posted on the ISO Internet "Home Page," at http://www.caiso.com or such other Internet address as the ISO may publish from time to time.

22. SCHEDULE VALIDATION TOLERANCES.

22.1 Temporary Simplification of Schedule Validation Tolerances.

Notwithstanding any other provision in the ISO Tariff, including the ISO Protocols, a Schedule shall be treated as a Balanced Schedule when aggregate Generation, adjusted for Transmission Losses, is within 20 MW of aggregate Demand, or such lower amount, greater than 1 MW, as may be established from time to time by the ISO. The ISO may establish the Schedule validation tolerance level at any time, between a range from 1 MW to 20 MW, by giving seven days' notice published on the ISO's "Home Page," at

23 METERED SUBSYSTEMS

23.1 General Nature of Relationship Between ISO and MSS

23.1.1 An entity that is determined by the ISO to qualify as a Metered Subsystem and that undertakes in writing to the ISO to comply with all applicable provisions of the ISO Tariff as specified in that written agreement as they may be amended from time to time, including, without limitation, the applicable provisions of this Section 23, shall be considered an MSS Operator and shall have the rights and obligations set forth in this Section 23. The ISO shall not be obligated to accept Schedules, Adjustment Bids or bids for Ancillary Services which would require Energy to be transmitted to or from a Metered Subsystem unless the written undertaking of the MSS Operator of the Metered Subsystem has become effective.

23.2 Coordination of Operations. Each MSS Operator shall operate its MSS at all times in accordance with Good Utility Practice and Applicable Reliability Criteria, including WECC and NERC criteria, and in a manner which ensures safe and reliable operation. All information pertaining to the physical state or operation, maintenance and failure of the MSS affecting the operation of the ISO Control Area that is made available to the ISO by the MSS Operator shall also be made available to Scheduling Coordinators, provided that the ISO shall provide reasonable notice to the MSS Operator. The ISO shall not be required to make information available to the MSS Operator other than information that is made available to Scheduling Coordinators.

23.3 Coordinating Maintenance Outages of MSS Facilities. Each MSS Operator shall make appropriate arrangements to coordinate Outages of Generating Units in accordance with Section 5. Each MSS Operator shall make appropriate arrangements to coordinate Outages of transmission facilities forming part of its MSS that will have an effect, or are reasonably likely to have an effect, on any interconnection between the MSS and the system of a Participating TO,

23.4.3 coordinate with the ISO, Participating TOs and Generators to ensure that ISO Controlled Grid Critical Protective Systems, including relay systems, are installed and maintained in order to function on a coordinated and complementary basis with the protective systems of the MSS, Participating TOs and Generators and notify the ISO as soon as is reasonably possible of any condition of which it becomes aware that may compromise the ISO Controlled Grid Protective Systems;

23.4.4 be responsible for any Reliability Must-Run Generation and Voltage Support required for reliability of the MSS, including the responsibility for any costs of such Reliability Must-Run Generation, and Voltage Support and may satisfy this requirement through Generating Units owned by the MSS or under contract to the MSS;

23.4.5 be responsible for Black Start requirements for reliability of the MSS, however, if the MSS can self-provide this requirement, the MSS shall not pay its pro rata share of the Black Start requirement in accordance with Section 2.5.28.6; and

23.4.6 be responsible for Intra-Zonal Congestion Management and transmission line Outages within or at the boundary of the MSS, and all associated costs and not responsible for Intra-Zonal Congestion Management elsewhere in the Zone except to the extent that a Scheduling Coordinator is delivering Energy to or from the MSS.

23.5 Scheduling by or on behalf of a MSS Operator. All Schedules submitted on behalf of an MSS Operator for the delivery of Energy and Ancillary Services to Loads connected to the MSS and for the delivery of Energy and Ancillary Services from Generating Units forming part of the MSS or System Units shall be submitted by a Scheduling Coordinator that complies with all applicable provisions of the ISO Tariff, which Scheduling Coordinator may be the MSS Operator,

provided that the MSS Operator complies with all applicable requirements for Scheduling Coordinators. A Scheduling Coordinator shall separately identify Schedules that it submits on behalf of an MSS Operator.

23.5.1 Without limiting the foregoing, the Scheduling Coordinator for the MSS must submit gross generation information for the System Unit, Generating Unit, and information regarding imports, exports and Gross Loads to the ISO in the format and in accordance with the timelines applicable to other Scheduling Coordinators.

23.5.2 The Scheduling Coordinator for the MSS will designate, in discrete quantities and with prices for both Ancillary Services and Energy: (1) Schedules in Day-Ahead and Hour-Ahead Energy markets (including Schedules for internal Generation and internal Demand within the MSS), (2) bids or self-provided Schedules for Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve capacity and associated bid Energy, (3) Adjustment Bids, (4) Supplemental Energy bids, or (5) any feasible combination thereof.

23.6 System Emergencies.

23.6.1 In the event a System Emergency occurs or the ISO determines that a System Emergency is threatened or imminent, each MSS Operator shall comply with all directions from the ISO concerning the avoidance, management and alleviation of the System Emergency and shall comply with all procedures concerning System Emergencies set forth in the ISO Tariff.

23.6.2 During a System Emergency, the ISO and the MSS Operator shall communicate through their respective control centers and in accordance with procedures established in the agreement through which the MSS Operator undertakes to the ISO to comply with the provisions of the ISO Tariff.

MSS Operator does not operate its System Unit or Generating Units and schedule imports into the MSS, to match the metered Demand in the MSS and exports from the MSS; and (b) if the deviation between the Generation in the MSS and imports into the MSS and metered Demand in the MSS and exports from the MSS exceeds a deviation band equal to three percent (3%) of the lesser of the MSS Operator's metered or Hour-Ahead scheduled Demand and exports from the MSS, adjusted for Forced Outages and any ISO directed firm Load Shedding for the MSS's portfolio as a whole (the "Deviation Band"), then the Scheduling Coordinator for the MSS Operator shall pay the additional amounts specified in Section 23.12.2. The Scheduling Coordinator for an MSS Operator that chooses to follow its Load in accordance with this Section 23.12 shall provide sixty (60) days advance notice to the ISO. If the Scheduling Coordinator later desires not to follow the Load of the MSS Operator, the Scheduling Coordinator shall provide sixty (60) days advance notice to the ISO that it will no longer follow Load.

23.12.2 Under the circumstances described in Section 23.12.1, the Scheduling Coordinator for an MSS Operator shall pay amounts based on a price that is the effective weighted average Ex Post Price applicable to the MSS's Scheduling Coordinator for the billing interval (the "Deviation Price"). The revenue received from these payments will be used as an off-set to the ISO's Grid Management Charge. The payments due from a Scheduling Coordinator will be calculated as follows:

23.12.2.1 If the metered Generation resources and imports into the MSS exceed the metered Demand and exports from the MSS, and Energy expected to be delivered by the Scheduling Coordinator for the MSS in response to the ISO's Dispatch Instructions and/or Regulation set-point signals issued by the ISO's AGC by more than the Deviation Band, then the Scheduling Coordinator for the MSS Operator will pay the ISO an amount equal to one hundred percent (100%) of the product of the Deviation Price and the amount of the Imbalance Energy that is supplied in excess of the Deviation Band.

23.12.2.2 If metered Generation resources and imports into the MSS are insufficient to meet the metered Demand and exports from the MSS, and Energy expected to be delivered by the Scheduling Coordinator for the MSS in response to the ISO's Dispatch instructions and/or Regulation set-point signals issued by the ISO's AGC by more than the Deviation Band, then the Scheduling Coordinator for the MSS Operator shall pay the ISO an amount equal to the product of the Deviation Price and two hundred percent (200%) of the shortfall that is outside of the Deviation Band, in addition to the Imbalance Energy charges that may be applicable under the ISO Tariff.

23.12.3 If the ISO is charging Grid Management Charges for uninstructed deviations, and the Scheduling Coordinator for the MSS has uninstructed deviations associated with Load following from the MSS's resources, then the ISO will net the Generation and imports into the MSS to match the Demand and exports out of the MSS, and will not assess GMC associated with uninstructed deviations for such portion of Energy that is used to match MSS Demand and net exports.

23.12.3.1 If Generation, above the amount to cover Demand and exports, was sold into the ISO's Imbalance Energy market, then the Scheduling Coordinator for the MSS will be charged GMC associated with uninstructed deviations for this quantity.

23.12.3.2 If insufficient Generation and imports was available to cover Demand and exports, and the Scheduling Coordinator for the MSS purchased Imbalance Energy from the ISO's market, then such Scheduling Coordinator will be charged GMC associated with uninstructed deviations for this quantity.

23.12.3.3 Only GMC associated with uninstructed deviations (the Ancillary Services and Real-Time Energy Operations Charge (ASREO)) will be treated on a net basis.

GMC for Control Area Services (CAS) will be charged based on Gross Load and exports out of the MSS. The Scheduling Coordinator for the MSS Operator will be assessed the GMC Congestion Management Charge (CONG) in accordance with Section 8.3. Ancillary Service bids accepted by the ISO and Instructed Energy will be assessed the GMC ASREO.

23.13 Information Sharing.

23.13.1 System Planning Studies and Forecasts.

The ISO, the MSS Operator and Participating TOs shall share information such as projected Load growth and system expansions necessary to conduct necessary system planning studies to the extent that these may impact the operation of the ISO Control Area. Each MSS Operator shall provide to the ISO annually its ten-year forecasts of Demand growth, internal Generation, and expansion of or replacement for any transmission facilities that are part of the MSS that will or may significantly affect any point of interconnection between the MSS and the ISO Controlled Grid. Such forecasts shall be provided on the date that UDCs are required to submit forecasts to the ISO under Section 4.8.1. Each MSS Operator or each Scheduling Coordinator for an MSS Operator shall also submit weekly and monthly peak Demand Forecasts in accordance with the ISO's protocols.

23.13.2 System Surveys and Inspections.

The ISO and each MSS Operator shall cooperate with each other in performing system surveys and inspections to the extent these relate to the operation of the ISO Control Area.

23.13.3 Reports.

23.13.3.1 The ISO shall make available to each MSS Operator any public annual reviews or reports regarding performance standards, measurements and incentives relating to the ISO

Controlled Grid or the integrity of the MSS respectively. Each MSS Operator and the ISO each shall also inform the other as promptly as possible of any incident of which it becomes aware (including, but not limited to, equipment outages, over-loads or alarms) which, in the case of the MSS Operator, is reasonably likely to threaten the reliability of the ISO Controlled Grid, or, in the case of the ISO, is reasonably likely to adversely affect the MSS. Such information shall be provided in a form and content which is reasonable in all the circumstances, sufficient to provide timely warning to the entity receiving the information of the threat and, in the case of the ISO, not unduly discriminatory with respect to the ISO's provision of similar information to other entities.

23.13.3.5 Forms. The ISO shall, in consultation with MSS Operators, jointly develop and, as necessary, revise, any necessary forms and procedures for collection, study, treatment, and transmittal of system data, information, reports and forecasts.

23.14 Installation of and Rights of Access to MSS Facilities.

23.14.1 Installation of Facilities.

23.14.1.1 Meeting Service Obligations.

The ISO and each MSS Operator shall each have the right, if mutually agreed, on reasonable notice to install or to have installed equipment (including metering equipment) or other facilities on the property of the other, to the extent that such installation is necessary for the installing party to meet its service obligations unless to do so would have a negative impact on the reliability of the service provided by the party owning the property.

23.14.1.2 Governing Agreements for Installations.

The ISO and the MSS Operator shall enter into agreements governing the installation of equipment or other facilities containing customary and reasonable terms and conditions.

Coordinator for the MSS Operator shall not be obligated to bear any share of the ISO's costs for any summer Demand reduction program or for any summer reliability Generation procurement program pursuant to ISO Tariff Section 2.3.5.1.8 for the calendar year for which the demonstration is made.

23.16.3 If the ISO is compensating Generating Units for Emissions Costs, Start-Up Fuel Costs and Minimum Load Costs, and if MSS Operator charges the ISO for the Emissions Costs, Start-Up Fuel Costs and Minimum Load Costs, of the Generating Units serving the Load of the MSS, then the Scheduling Coordinator for the MSS shall bear its proportionate share of the total amount of those costs incurred by the ISO based on the MSS gross metered Demand and exports and the Generating Units shall be made available to the ISO through the submittal of Supplemental Energy bids. If the MSS Operator chooses not to charge the ISO for the Emissions Costs, Start-Up Fuel Costs and Minimum Load Costs of the Generating Units serving the Load of the MSS, then the Scheduling Coordinator for the MSS shall bear its proportionate share of the total amount of those costs incurred by the ISO based on the MSS's net metered Demand and exports. The MSS Operator shall make the election whether to charge the ISO for these costs on an annual basis on November 1 for the following calendar year.

23.16.4 The Scheduling Coordinator for the MSS shall be responsible for Transmission Losses, in accordance with the ISO Tariff, only within the MSS, at any points of interconnection between the MSS and the ISO Controlled Grid, and for the delivery of Energy to the MSS or from the MSS, provided the MSS Operator fulfills its obligation to provide for Transmission Losses on the transmission facilities forming part of the MSS. A Generation Meter Multiplier shall be assigned to the Generating Units on the MSS at the Points of Interconnection for use of the ISO Controlled Grid. That GMM shall be 1.0 for all Generating Units within the MSS that are located at or behind a Point of Interconnection, to the extent that the Load at the Point of Interconnection for that portion of the MSS exceeds the amount of Generation produced by the Generating Units connected to that portion of the MSS, except that a GMM shall be calculated by the ISO for

Energy produced pursuant to a Dispatch instruction from the ISO.

23.16.5 If the MSS Operator has elected to follow its Load in accordance with Section 23.12, then the MSS is not eligible to receive bid cost recovery as provided for in Section 11.2.4.1.1.1 and the Scheduling Coordinator for the MSS shall be allocated costs associated with bid cost recovery on a net Metered Demand basis. If the MSS Operator has elected to not follow its Load in accordance with Section 23.12, then the MSS is eligible to receive bid cost recovery as provided for in Section 11.2.4.1.1.1, if applicable, subject to resource-specific performance review, and the Scheduling Coordinator for the MSS shall be allocated costs associated with bid cost recovery on a gross metered Demand basis.

24. [NOT USED]

25. [NOT USED]

26. TEMPORARY CHANGES TO ANCILLARY SERVICES PENALTIES

26.1 Application and Termination

The temporary change, respecting Ancillary Services penalties, set out in Section 26.2 shall continue in effect until such time as the Chief Executive Officer of the ISO issues a Notice of Full-Scale Operations, posted on the ISO Internet "Home Page", at http://www.caiso.com, or such other Internet address as the ISO may publish from time to time, specifying the date on which this Section 26 shall cease to apply, which date shall be not less than seven (7) days after the Notice of Full-Scale Operations is issued.

26.2 For so long as this Section 26.2 remains in effect, Scheduling Coordinators shall not be liable for the penalties specified in Section 2.5.26 of the ISO Tariff if, as a result of limitations associated with the ISO's Congestion Management software, the scheduled output of the resource from which the Scheduling Coordinator has committed to provide an Ancillary Service is adjusted by the ISO to a level that conflicts with the Scheduling Coordinator's Ancillary Service capacity commitments, thereby resulting in a failed availability test.

28.1.3 Negative Decremental Energy Bids

Negative decremental Energy bids into the ISO Markets less than -$30/MWh (minus thirty dollars per MWh) shall not be eligible to set any Market Clearing Price and, if Dispatched, shall be paid as bid. If the ISO Dispatches a bid below -$30/MWh, the supplier must submit a detailed breakdown of the component costs justifying the bid to the ISO and to the Federal Energy Regulatory Commission no later than seven (7) days after the end of the month in which the bid was submitted. The ISO will treat such information as confidential and will apply the procedures in Section 20.3.4 of this ISO Tariff with regard to requests for disclosure of such information. The ISO shall pay suppliers for amounts in excess of $-30/MWh after those amounts have been justified.

29. [NOT USED]

30. YEAR 2000 COMPLIANCE

30.1 Y2K Compliance

"Y2K Compliance" or "Y2K Compliant" means hardware, software, firmware, or other systems or processes (hereafter "systems and processes") that correctly manage, calculate, compare and sequence date data from, into and between the 20th and 21st centuries, including leap year calculations, without human intervention. Y2K Compliant systems and processes must utilize input and output date formats that are compatible with the ISO's systems and processes, must conform to the International Organization for Standardization ISO 8601:1988 standards for representation of dates and must not cause incorrect date calculations.

30.2 Responsibility for Y2K Compliance

It is the sole responsibility of each Market Participant or other entity that interfaces with the ISO's systems and processes to ensure that the entity's interfacing systems or processes are Y2K Compliant. The ISO will provide joint Y2K test opportunities to ensure interoperability between the ISO systems and external systems that interface with the ISO (e.g., Scheduling Coordinators, and other entities). This proactive test program is an opportunity to minimize the possibilities of transmitting Y2K related erroneous data to the ISO. Participation in this testing program is voluntary, and not a requirement.

30.3 Disconnection of Non-Y2K Compliant Systems and Processes

In order to protect and maintain the integrity of the ISO's systems and processes, the ISO shall have the authority to immediately disconnect the systems or processes of any Scheduling Coordinator or other entity that is believed by the ISO to be passing Y2K related erroneous data; i.e., data from systems and processes that do not meet the Section 30.1 standards for Y2K Compliance. The ISO will immediately notify the disconnected Scheduling Coordinator or other entity of the reason for the action taken by the ISO. The ISO shall permit such Scheduling Coordinator or other entity to reestablish interfaces with the ISO after receiving and approving documented test results showing that the disconnected systems or processes are Y2K Compliant and would not otherwise adversely affect the ISO's systems and processes. The ISO will review and approve or reject documented test results within two (2) Business Days of their receipt. The ISO will reconnect the entity within one (1) Business Day of the ISO's approval.

Access Charge A charge paid by all UDCs, MSSs and, in certain cases, Scheduling Coordinators, delivering Energy to Gross Load in the PTO Service Area, as set forth in Section 7.1. The Access Charge includes the High Voltage Access Charge, the Transition Charge and the Low Voltage Access Charge. The Access Charge will recover the Participating TO's Transmission Revenue Requirement in accordance with Appendix F, Schedule 3.

Active Zone The Zones so identified in Appendix I to the ISO Tariff.

Adjustment Bid A bid in the form of a curve defined by (i) the minimum MW output to which a Scheduling Coordinator will permit a resource (Generating Unit or Dispatchable Load) included in its Schedule or, in the case of an inter-Scheduling Coordinator trade, included in its Schedule or the Schedule of another Scheduling Coordinator, to be redispatched by the ISO; (ii) the maximum MW output to which a Scheduling Coordinator will permit the resource included in its Schedule or, in the case of an inter-Scheduling Coordinator trade, included in its Schedule or the Schedule of another Scheduling Coordinator, to be redispatched by the ISO; (iii) up to a specified number of MW values in between; (iv) a preferred MW operating point; and (v) for the ranges between each of the MW values greater than the preferred operating point, corresponding prices (in $/MWh) for

Alert Notice	A Notice issued by the ISO when the operating requirements of the ISO Controlled Grid are marginal because of Demand exceeding forecast, loss of major Generation, or loss of transmission capacity that has curtailed imports into the ISO Control Area, or if the Hour-Ahead Market is short on scheduled Energy and Ancillary Services for the ISO Control Area.
Ancillary Services	Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve, Voltage Support and Black Start together with such other interconnected operation services as the ISO may develop in cooperation with Market Participants to support the transmission of Energy from Generation resources to Loads while maintaining reliable operation of the ISO Controlled Grid in accordance with Good Utility Practice.
Ancillary Service Provider	A Participating Generator or Participating Load who is eligible to provide an Ancillary Serviced.

Applicable Reliability Criteria	The reliability standards established by NERC, WECC, and Local Reliability Criteria as amended from time to time, including any requirements of the NRC.
Applicants	Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company and any others as applicable.

Approved Credit Rating

With respect to whether security must be posted for payment of the Grid Management Charge:

(a) A short-term taxable commercial paper debt rating of not less than any one of the following: (i) A1 by Standard and Poor's Corporation; (ii) F1 by Fitch Ratings; or (iii) P1 by Moody's Investors Service. This rating shall be an issuer, or counterpart rating, without the benefit of credit enhancement.

(b) A short-term tax exempt commercial paper debt rating of not less than any one of the following: (i) A1 by Standard and Poor's Corporation; (ii) V1 by Fitch Ratings; or (iii) VMIG1 by Moody's Investors Service. This rating shall be an issuer, or counterparty rating, without the benefit of credit enhancement.

With respect to whether security must be posted for payment of all charges other than the Grid Management Charge:

(c) A short-term tax exempt commercial paper debt rating of not less than any one of the following: (i) A2 by Standard and Poor's Corporation; (ii) F2 by Fitch Ratings; or (iii) P2 by Moody's Investors Service. This rating shall be an issuer, or counterparty rating, without the benefit of credit enhancement.

(d) A short-term tax exempt commercial paper debt rating of not less than any one of the following: (i) A2 by Standard and Poor's Corporation; (ii) V2 by Fitch Ratings; or (iii) VMIG2 by Moody's Investors Service. This rating shall be an issuer, or counterparty rating, without the benefit of credit

enhancement.

(e) A long-term debt rating of not less than any one of the following: (i) A- by Standard and Poor's Corporation; (ii) A- by Fitch Ratings; or (iii) A3 by Moody's Investors Service. This rating shall be an issuer, or counterparty rating, without the benefit of credit enhancement.

With respect to whether security must be posted for payment of all charges:

(f) A federal agency shall be deemed to have an Approved Credit Rating if its financial obligations under the ISO Tariff are backed by the full faith and credit of the United States.

(g) A California state agency shall be deemed to have an Approved Credit Rating if its financial obligations under the ISO Tariff are backed by the full faith and credit of the State of California.

(h) Another credit rating approved by the ISO Governing Board.

Approved Load Profile Local Regulatory Authority approved Load profiles applied to cumulative End-Use Meter Data in order to allocate consumption of Energy to Settlement Periods.

Approved Maintenance Outage A Maintenance Outage which has been approved by the ISO through the ISO Outage Coordination Office.

Automatic Mitigation Procedure (AMP) The market power mitigation procedure described in MMIP Appendix A.

Available Transfer Capacity	For a given transmission path, the capacity rating in MW of the path established consistent with ISO and WECC transmission capacity rating guidelines, less any reserved uses applicable to the path.
Balanced Schedule	A Schedule shall be deemed balanced when Generation, adjusted for Transmission Losses equals forecast Demand with respect to all entities for which a Scheduling Coordinator schedules.
Balancing Account	An account set up to allow periodic balancing of financial transactions that, in the normal course of business, do not result in a zero balance of cash inflows and outflows.

Black Start	The procedure by which a Generating Unit self-starts without an external source of electricity thereby restoring power to the ISO Controlled Grid following system or local area blackouts.
Black Start Generator	A Participating Generator in its capacity as party to an Interim Black Start Agreement with the ISO for the provision of Black Start services, but shall exclude Participating Generators in their capacity as providers of Black Start services under their Reliability Must-Run Contracts.
Bulk Supply Point	A UDC metering point.
Business Day	A day on which banks are open to conduct general banking business in California.
C.F.R.	Code of Federal Regulations.
Circular Schedule	A Schedule or set of Schedules that creates a closed loop of Energy Schedules between the ISO Controlled Grid and one or more other Control Areas that do not have a source and sink in separate Control Areas, which includes Energy scheduled in a counter direction over a Congested Inter-Zonal Interface through two or more Scheduling Points. A closed loop of Energy Schedules that includes a transmission segment on the Pacific DC Intertie shall not be a Circular Schedule because such a Schedule directly changes power flows on the network and can mitigate Congestion between SP15 and NP15.

Completed Application Date	For purposes of Section 5.7, the date on which a New Facility Operator submits an Interconnection Application to the ISO that satisfies the requirements of the ISO Tariff and the TO Tariff of the Interconnecting PTO.
Completed Interconnection Application	An Interconnection Application that meets the information requirements as specified by the ISO and posted on the ISO Home Page.
Congestion	A condition that occurs when there is insufficient Available Transfer Capacity to implement all Preferred Schedules simultaneously or, in real time, to serve all Generation and Demand. "Congested" shall be construed accordingly.
Congestion Management	The alleviation of Congestion in accordance with Applicable ISO Protocols and Good Utility Practice.
Congestion Management Charge	The component of the Grid Management Charge that provides for the recovery of the ISO's costs of operating the Congestion Management process including, but not limited to, the management and operation of Inter-Zonal Congestion markets, Adjustment Bids, taking Firm Transmission Rights and Existing Contracts into account, and determining the price for mitigating Congestion for flows on Congested paths. The formula for determining the Congestion Management Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

that is separate from the switchyard to which the Generating Unit is connected will not be considered to be electrically connected at the same point); and

(b) Load that is isolated electrically from the ISO Control Area (*i.e.*, Load that is not synchronized with the ISO Control Area).

Converted Rights Those transmission service rights as defined in Section 2.4.4.2.1 of the ISO Tariff.

Core Reliability Services Charge The component of the Grid Management Charge that provides for the recovery of the ISO's costs of providing a basic, non-scalable level of reliable operation for the ISO Control Area and meeting regional and national reliability requirements. The formula for determining the Core Reliability Services Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

CPUC The California Public Utilities Commission, or its successor.

Critical Protective System	Facilities and sites with protective relay systems and Remedial Action Schemes that the ISO determines may have a direct impact on the ability of the ISO to maintain system security and over which the ISO exercises Operational Control.
CTC (Competition Transition Charge)	A non-bypassable charge that is the mechanism that the California Legislature and the CPUC mandated to permit recovery of costs stranded as a result of the shift to the new market structure.
Curtailable Demand	Demand from a Participating Load that can be curtailed at the direction of the ISO in the real-time Dispatch of the ISO Controlled Grid. Scheduling Coordinators with Curtailable Demand may offer it to the ISO to meet Non-Spinning Reserve or Replacement Reserve requirements.
Data Adequacy Requirement	Any applicable minimum data requirements of the state agency responsible for generation siting or of any Local Regulatory Authority.
Day-Ahead	Relating to a Day-Ahead Market or Day-Ahead Schedule.
Day-Ahead Market	The forward market for Energy and Ancillary Services to be supplied during the Settlement Periods of a particular Trading Day that is conducted by the ISO and other Scheduling Coordinators and which closes with the ISO's acceptance of the Final Day-Ahead Schedule.
Day-Ahead Schedule	A Schedule prepared by a Scheduling Coordinator or the ISO before the beginning of a Trading Day indicating the levels of Generation and Demand scheduled for each Settlement Period of that Trading Day.
Default GMM	Pre calculated GMM based on historical Load and interchange levels.

Delivery Point	The point where a transaction between Scheduling Coordinators is deemed to take place. It can be either the Generation input point, a Demand Take-Out Point, or a transmission bus at some intermediate location.
Delivery Upgrade	The transmission facilities, other than Direct Assignment Facilities and Reliability Upgrades, necessary to relieve Constraints on the ISO Controlled Grid and to ensure the delivery of energy from a New Facility to Load.
Demand	The rate at which Energy is delivered to Loads and Scheduling Points by Generation, transmission or distribution facilities. It is the product of voltage and the in-phase component of alternating current measured in units of watts or standard multiples thereof, e.g., 1,000W=1kW, 1,000kW=1MW, etc.
Demand Forecast	An estimate of Demand over a designated period of time.

Direct Assignment Facility The transmission facilities necessary to physically and electrically interconnect a New Facility Operator to the ISO Controlled Grid at the point of Interconnection.

Dispatch The operating control of an integrated electric system to: i) assign specific Generating Units and other sources of supply to effect the supply to meet the relevant area Demand taken as Load rises or falls; ii) control operations and maintenance of high voltage lines, substations, and equipment, including administration of safety procedures; iii) operate interconnections; iv) manage Energy transactions with other interconnected Control Areas; and v) curtail Demand.

Dispatch Instruction An instruction by the ISO to a resource for increasing or decreasing its energy supply or demand from the Hour-Ahead Schedule to a specified operating point.

Dispatch Interval The time period, which may range between five (5) and thirty (30) minutes, over which the ISO's RTD Software measures deviations in Generation and Demand, and selects Ancillary Service and Supplemental Energy resources to provide balancing Energy in response to such deviations. The Dispatch Interval shall be five (5) minutes. Following a decision by the ISO Governing Board, the ISO may, by seven (7) days' notice published on the ISO's Home Page, at http://www.caiso.com (or such other internet address as the ISO may publish from time to time), increase or decrease the Dispatch Interval within the range of five (5) to thirty (30) minutes.

Dispatch Interval Ex Post Prices	The price of Imbalance Energy determined each Dispatch Interval based on 1) the Imbalance Energy requirements in that Dispatch Interval, and 2) the Energy Bid price of the resource eligible to set the price. The Dispatch Interval Ex Post Price is used to determine other prices used to settle Imbalance Energy.
Dispatch Operating Point	The expected operating point of a resource that has received a Dispatch Instruction. The resource is expected to operate at the Dispatch Operating Point after completing the Dispatch Instruction, taking into account any relevant ramp rate and time delays. Energy expected to be produced or consumed above or below the Final Hour-Ahead Schedule in response to a Dispatch Instruction constitutes Instructed Imbalance Energy. For resources that have not received a Dispatch Instruction, the Dispatch Operating Point defaults to the corresponding Final Hour-Ahead Schedule.
Dispatchable Load	Load which is the subject of an Adjustment Bid.

Distribution System	The distribution assets of an IOU or Local Publicly Owned Electric Utility.
EEP (Electrical Emergency Plan)	A plan to be developed by the ISO in consultation with UDCs to address situations when Energy reserve margins are forecast to be below established levels.

Eligible Customer	(i) any utility (including Participating TOs, Market Participants and any power marketer), Federal power marketing agency, or any person generating Energy for sale or resale; Energy sold or produced by such entity may be Energy produced in the United States, Canada or Mexico; however, such entity is not eligible for transmission service that would be prohibited by Section 212(h)(2) of the Federal Power Act; and (ii) any retail customer taking unbundled transmission service pursuant to a state retail access program or pursuant to a voluntary offer of unbundled retail transmission service by the Participating TO.
Eligible Intermittent Resource	A Generating Unit that is powered solely by 1) wind, 2) solar energy, or 3) hydroelectric potential derived from small conduit water distribution facilities that do not have storage capability.
Emissions Cost Charge	The charge determined in accordance with Section 2.5.23.3.6
Emissions Cost Demand	The level of Demand specified in Section 2.5.23.3.6.3

Emissions Cost Invoice	The invoice submitted to the ISO in accordance with Section 2.5.23.3.6.6.
Emissions Cost Trust Account	The trust account established in accordance with Section 2.5.23.3.6.2.
Emissions Costs	The mitigation fees, excluding capital costs, assessed against a Generating Unit by a state or federal agency, including air quality districts, for exceeding applicable NOx emissions limitations.

EMS (Energy Management System)	A computer control system used by electric utility dispatchers to monitor the real-time performance of the various elements of an electric system and to control Generation and transmission facilities.
Encumbrance	A legal restriction or covenant binding on a Participating TO that affects the operation of any transmission lines or associated facilities and which the ISO needs to take into account in exercising Operational Control over such transmission lines or associated facilities if the Participating TO is not to risk incurring significant liability. Encumbrances shall include Existing Contracts and may include: (1) other legal restrictions or covenants meeting the definition of Encumbrance and arising under other arrangements entered into before the ISO Operations Date, if any; and (2) legal restrictions or covenants meeting the definition of Encumbrance and arising under a contract or other arrangement entered into after the ISO Operations Date.
End-Use Customer or End-User	A purchaser of electric power who purchases such power to satisfy a Load directly connected to the ISO Controlled Grid or to a Distribution System and who does not resell the power.
End-Use Meter Data	Meter Data that measures the Energy consumption in respect of End-Users gathered, edited and validated by Scheduling Coordinators and submitted to the ISO in Settlement quality form.
End-Use Meter	A metering device collecting Meter Data with respect to the Energy consumption of an End-User.

Energy	The electrical energy produced, flowing or supplied by generation, transmission or distribution facilities, being the integral with respect to time of the instantaneous power, measured in units of watt-hours or standard multiples thereof, e.g., 1,000 Wh=1kWh, 1,000 kWh=1MWh, etc.
Energy Bid	The price at or above which a Generator has agreed to produce the next increment of Energy.
Energy Transmission Services Net Energy Charge	The component of the Grid Management Charge that provides, in conjunction with the Energy Transmission Services Uninstructed Deviations Charge, for the recovery of the ISO's costs of providing reliability on a scalable basis, i.e., a function of the intensity of the use of the transmission system within the Control Area and the occurrence of system outages and disruptions. The formula for determining the Energy Transmission Services Net Energy Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.
Energy Transmission Services Uninstructed Deviations Charge	The component of the Grid Management Charge that provides, in conjunction with the Energy Transmission Services Net Energy Charge, for the recovery of the ISO's costs of providing reliability on a scalable basis, in particular for the costs associated with balancing transmission flows that result from uninstructed deviations. The formula for determining the Energy Transmission Services Uninstructed Deviations Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

Entitlements	The right of a Participating TO obtained through contract or other means to use another entity's transmission facilities for the transmission of Energy.
Environmental Dispatch	Dispatch designed to meet the requirements of air quality and other environmental legislation and environmental agencies having authority or jurisdiction over the ISO.
Ex Post GMM	GMM that is calculated utilizing the real-time Power Flow Model in accordance with Section 7.4.2.1.2.
Ex Post Price	The Hourly Ex Post Price, the Dispatch Interval Ex Post Price, the Resource-Specific Settlement Interval Ex Post Price, or the Zonal Settlement Interval Ex Post Price.
Ex Post Transmission Loss	Transmission Loss that is calculated based on Ex Post GMM.

Existing Contracts	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.
Existing High Voltage Facility	A High Voltage Transmission Facility of a Participating TO that was placed in service on or before the Transition Date defined in Section 4.2 of Schedule 3 of Appendix F.
Existing Rights	Those transmission service rights defined in Section 2.4.4.1.1 of the ISO Tariff.
Expedited Interconnection Agreement	A contract between a party which has submitted a Request for Expedited Interconnection Procedures and an Interconnection PTO under which the ISO and an Interconnecting PTO agree to process, on an expedited basis, the Interconnection Application of a New Facility Operator and which sets forth the terms, conditions, and cost responsibilities for such interconnection.
Facility Owner	An entity owning transmission, Generation, or distribution facilities connected to the ISO Controlled Grid.
Facility Study	An engineering study conducted by a Participating TO to determine required modifications to the Participating TO's transmission system, including the cost and scheduled completion date for such modifications that will be required to provide needed services.
Facility Study Agreement	An agreement between a Participating TO and either a Market Participant, Project Sponsor, or identified principal beneficiaries pursuant to which the Market Participants, Project Sponsor, and identified principal beneficiaries agree to reimburse the Participating TO for the cost of a Facility Study.

FERC	The Federal Energy Regulatory Commission or its successor.
FERC Annual Charges	Those charges assessed against a public utility by the FERC pursuant to 18 C.F.R. § 382.201 and any related statutes or regulations, as they may be amended from time to time.
FERC Annual Charge Recovery Rate	The rate to be paid by Scheduling Coordinators for recovery of FERC Annual Charges assessed against the ISO for transactions on the ISO Controlled Grid.
FERC Annual Charge Trust Account	An account to be established by the ISO for the purpose of maintaining funds collected from Scheduling Coordinators for FERC Annual Charges and disbursing such funds to the FERC.
Final Day-Ahead Schedule	The Day-Ahead Schedule which has been approved as feasible and consistent with all other Schedules by the ISO based upon the ISO's Day-Ahead Congestion Management procedures.

Final Hour-Ahead Schedule	The Hour-Ahead Schedule of Generation and Demand that has been approved by the ISO as feasible and consistent with all other Schedules based on the ISO's Hour-Ahead Congestion Management procedures.
Final Invoice	The invoice due from a RMR Owner to the ISO at termination of the RMR Contract.
Final Schedule	A Schedule developed by the ISO following receipt of a Revised Schedule from a Scheduling Coordinator.
Final Settlement Statement	The restatement or recalculation of the Preliminary Settlement Statement by the ISO following the issue of that Preliminary Settlement Statement.
Forbidden Operating Region	The operating region of a resource wherein the resource cannot operate in a stable manner and must ramp through at maximum ramp capacity.
Forced Outage	An Outage for which sufficient notice cannot be given to allow the Outage to be factored into the Day-Ahead Market or Hour-Ahead Market scheduling processes.
Forward Scheduling Charge	The component of the Grid Management Charge that provides for the recovery of the ISO's costs, including, but not limited to the costs of providing the ability to Scheduling Coordinators to forward schedule Energy and Ancillary Services and the cost of processing accepted Ancillary Service bids. For purposes of the Forward Scheduling Charge, a schedule is represented by each Final Hour-Ahead Schedule with a value other than 0 MW submitted to the scheduling infrastructure/scheduling

application system (import, export, Load, Generation, inter-Scheduling Coordinator trade, and Ancillary Services, including self-provided Ancillary Services) submitted to the ISO's scheduling infrastructure. The formula for determining the Forward Scheduling Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

FPA Parts II and III of the Federal Power Act, 16 U.S.C. § 824 et seq., as they may be amended from time to time.

FTR (Firm Transmission Right) A contractual right, subject to the terms and conditions of the ISO Tariff, that entitles the FTR Holder to receive, for each hour of the term of the FTR, a portion of the Usage Charges received by the ISO for transportation of energy from a specific originating Zone to a specific receiving Zone and, in the event of an uneconomic curtailment to manage Day-Ahead Congestion, to a Day-Ahead scheduling priority higher than that of a Schedule using Converted Rights capacity that does not have an FTR.

Generator	The seller of Energy or Ancillary Services produced by a Generating Unit.
GMM (Generation Meter Multiplier)	A number which when multiplied by a Generating Unit's Metered Quantity will give the total Demand to be served from that Generating Unit.
Good Faith Deposit	The deposit paid to the ISO by a New Facility Operator with submission of its Interconnection Application in accordance with Section 5.7.3.2, in an amount equal to $10,000, including any interest that accrues on the original amount, less any bank fees or other charges assessed on the escrow account. A New Facility Operator may satisfy its deposit obligation through any commercially available financial instrument determined to be satisfactory by the ISO.
Good Utility Practice	Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the

Grid Management Charge The ISO monthly charge on all Scheduling Coordinators that provides for the recovery of the ISO's costs listed in Section 8.2 through the seven service charges described in Section 8.3 calculated in accordance with the formula rate set forth in Appendix F, Schedule 1, Part A of this Tariff. The seven charges that comprise the Grid Management Charge consist of: 1) the Core Reliability Services Charge, 2) the Energy Transmission Services Net Energy Charge, 3) the Energy Transmission Services Uninstructed Deviations Charge, 4) the Forward Scheduling Charge, 5) the Congestion Management Charge, 6) the Market Usage Charge, and 7) the Settlements, Metering, and Client Relations Charge.

Grid Operations Charge An ISO charge that recovers Redispatch costs incurred due to Intra-Zonal Congestion in each Zone. These charges will be paid to the ISO by the Scheduling Coordinators, in proportion to their metered Demand within, and metered exports from, the Zone to a neighboring Control Area.

Gross Load For the purposes of calculating the transmission Access Charge, Gross Load is all Energy (adjusted for distribution losses) delivered for the supply of Loads directly connected to the transmission facilities or Distribution System of a UDC or MSS, and all Energy provided by a Scheduling Coordinator for the supply of Loads not directly connected to the transmission facilities or Distribution System of a UDC or MSS. Gross Load shall exclude Load with respect to which the Wheeling Access Charge is payable and the portion of the Load of an individual retail customer of a UDC, MSS, or Scheduling Coordinator that is served by a Generating Unit that: (a) is located on the customer's site or provides service to the customers site through arrangements as authorized by Section 218

High Voltage Wheeling Access Charge The Wheeling Access Charge associated with the recovery of a Participating TO's High Voltage Transmission Revenue Requirements in accordance with Section 7.1.

Hour-Ahead Relating to an Hour-Ahead Market or an Hour-Ahead Schedule.

Hour-Ahead Market The forward market for Energy and Ancillary Services to be supplied during a particular Settlement Period that is conducted by the ISO and other Scheduling Coordinators which opens after the ISO's acceptance of the Final Day-Ahead Schedule for the Trading Day in which the Settlement Period falls and closes with the ISO's acceptance of the Final Hour-Ahead Schedule.

Hour-Ahead Schedule A Schedule prepared by a Scheduling Coordinator or the ISO before the beginning of a Settlement Period indicating the changes to the levels of Generation and Demand scheduled for that Settlement Period from that shown in the Final Day-Ahead Schedule.

Hourly Ex Post Price	The Energy-weighted average of the Dispatch Interval Ex Post Prices in each Zone during each Settlement Period. The Hourly Ex Post Price will vary between Zones when Congestion is present. This price is used in the Regulation Energy Payment Adjustment and in RMR settlements.
Hourly Pre-Dispatch	The process in which the ISO Dispatches Energy Bids from System Resources before the start of the next Settlement Period for the entire duration of that Settlement Period.
Hydro Spill Generation	Hydro-electric Generation in existence prior to the ISO Operations Date that: i) has no storage capacity and that, if backed down, would spill; ii) has exceeded its storage capacity and is spilling even though the generators are at full output, or iii) has inadequate storage capacity to prevent loss of hydro-electric Energy either immediately or during the forecast period, if hydro-electric Generation is reduced; iv) has increased regulated water output to avoid an impending spill.
Identification Code	An identification number assigned to each Scheduling Coordinator by the ISO.
Imbalance Energy	Imbalance Energy is Energy from Regulation, Spinning and Non-Spinning Reserves, or Replacement Reserve, or Energy from other Generating Units, System Units, System Resources, or Loads that are able to respond to the ISO's request for more or less Energy.
Inactive Zone	All Zones which the ISO Governing Board has determined do not have a workably competitive Generation market and as set out in Appendix I to the ISO Tariff.

Incremental Change	The change in dollar value of a specific charge type from the Preliminary Settlement Statement to the Final Settlement Statement including any new charge types or Trading Day charges appearing for the first time on the Final Settlement Statement.
Instructed Imbalance Energy	The real-time change in Generation output or Demand (from dispatchable Generating Units, System Units, System Resources or Loads) which is instructed by the ISO to ensure that reliability of the ISO Control Area is maintained in accordance with Applicable Reliability Criteria. Sources of Imbalance Energy include Spinning and Non-Spinning Reserves, Replacement Reserve, and Energy from other dispatchable Generating Units, System Units, System Resources or Loads that are able to respond to the ISO's request for more or less Energy.
Inter-Scheduling Coordinator Ancillary Service Trades	Ancillary Service transactions between Scheduling Coordinators.
Inter-Scheduling Coordinator Energy Trades	Energy transactions between Scheduling Coordinators.
Inter-Zonal Congestion	Congestion across an Inter-Zonal Interface.

ISO ADR Procedures	The procedures for resolution of disputes or differences set out in Section 13 of the ISO Tariff, as amended from time to time.
ISO Audit Committee	A Committee of the ISO Governing Board appointed pursuant to Article IV, Section 5 of the ISO bylaws to (1) review the ISO's annual independent audit (2) report to the ISO Governing Board on such audit, and (3) to monitor compliance with the ISO Code of Conduct.
ISO Authorized Inspector	A person authorized by the ISO to certify, test, inspect and audit meters and Metering Facilities (as that term is defined in the ISO Metering Protocol) in accordance with the procedures established by the ISO pursuant to the ISO Protocols on metering.
ISO Bank	The bank appointed by the ISO from time to time for the purposes of operating the Settlement process.
ISO Clearing Account	The account in the name of the ISO with the ISO Bank to which payments are required to be transferred for allocation to ISO Creditors in accordance with their respective entitlements.
ISO Code of Conduct	For employees, the code of conduct for officers, employees and substantially full-time consultants and contractors of the ISO as set out in exhibit A to the ISO bylaws; for Governors, the code of conduct for governors of the ISO as set out in exhibit B to the ISO bylaws.
ISO Control Area Balancing Function	The real-time Dispatch of Generation (and Curtailable Demand), directed by the ISO, to balance with actual Demand during the current operating hour to meet operating Reliability Criteria.
ISO Control Center	The Control Center established, pursuant to Section 2.3.1.1 of the ISO Tariff.

ISO Market

Any of the markets administered by the ISO under the ISO Tariff, including, without limitation, Imbalance Energy, Ancillary Services, and FTRs.

ISO Memorandum Account

The memorandum account established by each California IOU pursuant to California Public Utilities Commission Order D. 96-08-038 date August 2, 1996 which records all ISO startup and development costs incurred by that California IOU.

ISO Metered Entity

a) any one of the following entities that is directly connected to the ISO Controlled Grid:

i. a Generator other than a Generator that sells all of its Energy (excluding any Energy consumed by auxiliary load equipment electrically connected to that Generator at the same point) and Ancillary Services to the UDC in whose Service Area it is located;

ii. an Eligible Customer; or

iii. an End-User other than an End-User that purchases all of its Energy from the UDC in whose Service Area it is located; and

(b) any one of the following entities:

i. a Participating Generator;

ii. a Participating TO in relation to its Tie Point Meters with other TOs or Control Areas;

iii. a Participating Load;

iv. a Participating Intermittent Resource; or

v. a utility that requests that UFE for its Service Area be calculated separately, in relation to its meters at points of connection of its Service Area with the systems of other

ISP (Internet Service Provider)	An independent network service organization engaged by the ISO to establish, implement and operate WEnet.
Load	An end-use device of an End-Use Customer that consumes power. Load should not be confused with Demand, which is the measure of power that a Load receives or requires.
Load Shedding	The systematic reduction of system Demand by temporarily decreasing the supply of Energy to Loads in response to transmission system or area capacity shortages, system instability, or voltage control considerations.
Local Furnishing Bond	Tax-exempt bonds utilized to finance facilities for the local furnishing of electric energy, as described in section 142(f) of the Internal Revenue Code, 26 U.S.C. § 142(f).
Local Furnishing Participating TO	Any Tax-Exempt Participating TO that owns facilities financed by Local Furnishing Bonds.
Local Publicly Owned Electric Utilities	A municipality or municipal corporation operating as a public utility furnishing electric service, a municipal utility district furnishing electric service, a public utility district furnishing electric services, an irrigation district furnishing electric services, a state agency or subdivision furnishing electric services, a rural cooperative furnishing electric services, or a joint powers authority that includes one or more of these agencies and that owns Generation or transmission facilities, or furnishes electric services over its own or its members' electric Distribution System.

Local Regulatory Authority	The state or local governmental authority responsible for the regulation or oversight of a utility.
Local Reliability Criteria	Reliability Criteria established at the ISO Operations Date, unique to the transmission systems of each of the Participating TOs.
Location Code	The code assigned by the ISO to Generation input points, and Demand Take-Out Points from the ISO Controlled Grid, and transaction points from trades between Scheduling Coordinators. This will be the information used by the ISO Controlled Grid, and transaction points for trades between Scheduling Coordinators. This will be the information used by the ISO to determine the location of the input, output, and trade points of Energy Schedules. Each Generation input and Demand Take-Out Point will have a designated Location Code identification for use in submitting Energy and Ancillary Service bids and Schedules.
Loop Flow	Energy flow over a transmission system caused by parties external to that system.
Loss Scale Factor	The ratio of expected Transmission Losses to the total Transmission Losses which would be collected if Full Marginal Loss Rates were utilized.
Low Voltage Access Charge	The Access Charge applicable under Section 7.1 to recover the Low Voltage Transmission Revenue Requirement of a Participating TO.
Low Voltage Transmission Facility	A transmission facility owned by a Participating TO or to which a Participating TO has an Entitlement that is represented by a Converted Right, which is not a High Voltage Transmission Facility, that is under the ISO Operational Control.

Low Voltage Transmission Revenue Requirement	The portion of a Participating TO's TRR associated with and allocable to the Participating TO's Low Voltage Transmission Facilities and Converted Rights associated with Low Voltage Transmission Facilities that are under the ISO Operational Control.
Low Voltage Wheeling Access Charge	The Wheeling Access Charge associated with the recovery of a Participating TO's Low Voltage Transmission Revenue Requirement in accordance with Section 7.1.
Maintenance Outage	A period of time during which an Operator (i) takes its transmission facilities out of service for the purposes of carrying out routine planned maintenance, or for the purposes of new construction work or for work on de-energized and live transmission facilities (e.g., relay maintenance or insulator washing) and associated equipment; or (ii) limits the capability of or takes its Generating Unit or System Unit out of service for the purposes of carrying out routine planned maintenance, or for the purposes of new construction work.

Metered Quantities	For each Direct Access End-User, the actual metered amount of MWh and MW; for each Participating Generator the actual metered amounts of MWh, MW, MVAr and MVArh.
Minimum Load Costs	The costs a Generating Unit incurs operating at minimum load.
Monthly Peak Load	The maximum hourly Demand on a Participating TO's transmission system for a calendar month, multiplied by the Operating Reserve Multiplier.
MSS (Metered Subsystem)	A geographically contiguous system located within a single Zone which has been operating as an electric utility for a number of years prior to the ISO Operations Date as a municipal utility, water district, irrigation district, State agency or Federal power administration subsumed within the ISO Control Area and encompassed by ISO certified revenue quality meters at each interface point with the ISO Controlled Grid and ISO certified revenue quality meters on all Generating Units or, if aggregated, each individual resource and Participating Load internal to the system, which is operated in accordance with a MSS Agreement described in Section 23.1.
MSS Operator	An entity that owns an MSS and has executed a MSS Agreement.

Municipal Tax Exempt Debt	An obligation the interest on which is excluded from gross income for federal tax purposes pursuant to Section 103(a) of the Internal Revenue Code of 1986 or the corresponding provisions of prior law without regard to the identity of the holder thereof. Municipal Tax Exempt Debt does not include Local Furnishing Bonds.
Must-Offer Generator	All entities defined in Section 5.11.1 of the ISO Tariff
Native Load	Load required to be served by a utility within its Service Area pursuant to applicable law, franchise, or statute.
NERC	The North American Electric Reliability Council or its successor.
Net FTR Revenue	The sum of: 1) the revenue received by the New Participating TO from the sale, auction, or other transfer of the FTRs provided to it pursuant to Section 9.4.3 FTR, or any substantively identical successor provision of the ISO Tariff; and 2) for each hour: a) the Usage Charge revenue received by the New Participating To associated with its Section 9.4.3 FTRs; minus b) Usage Charges that are: i) incurred by the Scheduling Coordinator for the New Participating TO under ISO Tariff Section 7.3.1.4, ii) associated with the New Participating TO's Section 9.4.3 FTRs, and iii) incurred by the New Participating TO for its energy transactions but not

incurred as a result of the use of the transmission by a third-party and minus c) the charges paid by the New Participating TO pursuant to Section 7.3.1.7, to the extent such charges are incurred by the Scheduling Coordinator of the New Participating TO on Congested Inter-Zonal Interfaces that are associated with the Section 9.4.3 FTRs provided to the New Participating TO. The component of New FTR Revenue represented by item 2) immediately above shall not be less than zero for any hour.

Net Negative Uninstructed Deviation

The real-time change in Generation or Demand associated with underscheduled Load (i.e., Load that appears unscheduled in real time) and overscheduled Generation (i.e., Generation that is scheduled in forward markets and does not appear in real time). Deviations are netted for each Settlement Interval, apply to a Scheduling Coordinator's entire portfolio, and include Load, Generation, imports and exports.

New Facility	A planned or Existing Generating Unit that requests, pursuant to Section 5.7 of the ISO Tariff, to interconnect or modify its interconnection to the ISO Controlled Grid.
New Facility License	A license issued by a federal, state or Local Regulatory Authority that enables an entity to build and operate a Generating Unit.
New Facility Operator	The owner of a planned New Facility, or its designee.
New High Voltage Facility	A High Voltage Transmission Facility of a Participating TO that is placed in service after the beginning of the transition period described in Section 4 of Schedule 3 of Appendix F, or a capital addition made and placed in service after the beginning of the transition period described in Section 4.2 of Schedule 3 of Appendix F to an Existing High Voltage Facility.
New Participating TO	A Participating TO that is not an Original Participating TO.
Nomogram	A set of operating or scheduling rules which are used to ensure that simultaneous operating limits are respected, in order to meet NERC and WECC operating criteria.

Non-Participating Generator	A Generator that is not a Participating Generator.
Non-Participating TO	A TO that is not a party to the TCA or for the purposes of Sections 2.4.3 and 2.4.4 of the ISO Tariff the holder of transmission service rights under an Existing Contract that is not a Participating TO.
Non-Spinning Reserve	The portion of off-line generating capacity that is capable of being synchronized and Ramping to a specified load in ten minutes (or load that is capable of being interrupted in ten minutes) and that is capable of running (or being interrupted) for at least two hours.
NRC	The Nuclear Regulatory Commission or its successor.
Operating Procedures	Procedures governing the operation of the ISO Controlled Grid as the ISO may from time to time develop, and/or procedures that Participating TOs currently employ which the ISO adopts for use.

Operating Reserve	The combination of Spinning and Non-Spinning Reserve required to meet WECC and NERC requirements for reliable operation of the ISO Control Area.
Operating Transfer Capability	The maximum capability of a transmission path to transmit real power, expressed in MW, at a given point in time.
Operational Control	The rights of the ISO under the Transmission Control Agreement and the ISO Tariff to direct Participating TOs how to operate their transmission lines and facilities and other electric plant affecting the reliability of those lines and facilities for the purpose of affording comparable non-discriminatory transmission access and meeting Applicable Reliability Criteria.
Operator	The operator of facilities that comprise the ISO Controlled Grid or a Participating Generator.
OPF (Optimal Power Flow)	A computer optimization program which uses a set of control variables (which may include active power and/or reactive power controls) to determine a steady-state operating condition for the transmission grid for which a set of system operating Constraints (which may include active power and/or reactive power constraints) are satisfied and an objective function (e.g. total cost or shift of schedules) is minimized.
Order No. 888	The final rule issued by FERC entitled "Promoting Wholesale Competition through Open Access Non- discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs., Regulations Preambles [1991-1996] ¶ 31,036 (1996), Order on Rehearing, Order No. 888-A, 78 FERC ¶ 61,220 (1997), as it may be amended from time to time.

Order No. 889 The final rule issued by FERC entitled "Open Access Same-Time Information System (formerly Real Time Information Networks) and Standards of Conduct," 61 Fed. Reg. 21,737 (May 10, 1996), FERC Stats. & Regs., Regulations Preambles [1991-1996] ¶ 31,035 (1996), Order on Rehearing, Order No. 889-A, 78 FERC ¶ 61,221 (1997), as it may be amended from time to time.

Original Participating TO A Participating TO that was a Participating TO as of January 1, 2000.

Outage Disconnection, separation or reduction in capacity, planned or forced, of one or more elements of an electric system.

Overgeneration A condition that occurs when total Generation exceeds total Demand in the ISO Control Area.

v) metered output is available only for the combined output of related multiple generating components and separate generating component metering is either impractical or economically inefficient.

Planning Procedures Procedures governing the planning, expansion and reliable interconnection to the ISO Controlled Grid that the ISO may, from time to time, develop.

PMS (Power Management System) The ISO computer control system used to monitor the real-time performance of the various elements of the ISO Controlled Grid, control Generation, and perform operational power flow studies.

Power Flow Model The computer software used by the ISO to model the voltages, power injections and power flows on the ISO Controlled Grid and determine the expected Transmission Losses and Generation Meter Multipliers.

Preferred Day-Ahead Schedule A Scheduling Coordinator's Preferred Schedule for the ISO Day-Ahead scheduling process.

Preferred Hour-Ahead Schedule A Scheduling Coordinator's Preferred Schedule for the ISO Hour-Ahead scheduling process.

Preferred Schedule The initial Schedule produced by a Scheduling Coordinator that represents its preferred mix of Generation to meet its Demand. For each Generator, the Schedule will include the quantity of output, details of any Adjustment Bids, and the location of the Generator. For each Load, the Schedule will include the quantity of consumption, details of any Adjustment Bids, and the location of the Load. The Schedule will also specify quantities and location of trades between the Scheduling Coordinator and all other Scheduling Coordinators. The

Preliminary Settlement Statement	The initial statement issued by the ISO of the calculation of the Settlements and allocation of the charges in respect of all Settlement Periods covered by the period to which it relates.
Price Overlap	The price range of bids for Supplemental Energy or Energy associated with Ancillary Services bids for any Dispatch Interval that includes decremental and incremental Energy Bids where the price of the decremental Energy Bids exceeds the price of the incremental Energy Bids.
Project Sponsor	A Market Participant or group of Market Participants or a Participating TO that proposes the construction of a transmission addition or upgrade in accordance with Section 3.2 of the ISO Tariff.
Proxy Price	The value determined for each gas-fired Generating Unit owned or controlled by a Must-Offer Generator in accordance with Section 2.5.23.3.4.
PTO Service Area	An area in which a Participating TO provides transmission service to itself, a UDC, a MSS, or End-Use Customers.

Ramping	Changing the loading level of a Generating Unit in a constant manner over a fixed time (e.g., ramping up or ramping down). Such changes may be directed by a computer or manual control.
RAS (Remedial Action Schemes)	Protective systems that typically utilize a combination of conventional protective relays, computer-based processors, and telecommunications to accomplish rapid, automated response to unplanned power system events. Also, details of RAS logic and any special requirements for arming of RAS schemes, or changes in RAS programming, that may be required.
Reactive Power Control	Generation or other equipment needed to maintain acceptable voltage levels on the ISO Controlled Grid and to meet reactive capacity requirements at points of interconnection on the ISO Controlled Grid.
Real Time Market	The competitive generation market controlled and coordinated by the ISO for arranging real-time Imbalance Energy.
Redispatch	The readjustment of scheduled Generation or Demand side management measures, to relieve Congestion or manage Energy imbalances.
Registered Data	Those items of technical data and operating characteristics relating to Generation, transmission or distribution facilities which are identified to the owners of such facilities as being information, supplied in accordance with ISO Protocols, to assist the ISO to maintain reliability of the ISO Controlled Grid and to carry out its functions.

Regulation

The service provided either by Generating Units certified by the ISO as equipped and capable of responding to the ISO's direct digital control signals, or by System Resources that have been certified by the ISO as capable of delivering such service to the ISO Control Area, in an upward and downward direction to match, on a real-time basis, Demand and resources, consistent with established NERC and WECC operating criteria. Regulation is used to control the power output of electric generators within a prescribed area in response to a change in system frequency, tieline loading, or the relation of these to each other so as to maintain the target system frequency and/or the established interchange with other areas within the predetermined limits. Regulation includes both the increase of output by a Generating Unit or System Resource ("Regulation Up") and the decrease in output by a Generating Unit or System Resource ("Regulation Down"). Regulation Up and Regulation Down are distinct capacity products, with separately stated requirements and Market Clearing Prices in each Settlement Period.

Regulation Energy Payment Adjustment

The additional value of regulating Energy.

Regulatory Must-Run Generation	Hydro Spill Generation and Generation which is required to run by applicable Federal or California laws, regulations, or other governing jurisdictional authority. Such requirements include but are not limited to hydrological flow requirements, environmental requirements, such as minimum fish releases, fish pulse releases and water quality requirements, irrigation and water supply requirements of solid waste Generation, or other Generation contracts specified or designated by the jurisdictional regulatory authority as it existed on December 20, 1995, or as revised by Federal or California law or Local Regulatory Authority.
Regulatory Must-Take Generation	Those Generation resources identified by CPUC, or a Local Regulatory Authority, the operation of which is not subject to competition. These resources will be scheduled by the relevant Scheduling Coordinator directly with the ISO on a must-take basis. Regulatory Must-Take Generation includes qualifying facility Generating Units as defined by federal law, nuclear units and pre-existing power purchase contracts with minimum energy take requirements.
Reliability Criteria	Pre-established criteria that are to be followed in order to maintain desired performance of the ISO Controlled Grid under contingency or steady state conditions.
Reliability Must-Run Charge (RMR Charge)	The sum payable by a Responsible Utility to the ISO pursuant to Section 5.2.7 of the ISO Tariff for the costs, net of all applicable credits, incurred under the RMR Contract.

Reliability Must-Run Contract (RMR Contract)	A Must-Run Service Agreement between the owner of an RMR Unit and the ISO.
Reliability Must-Run Generation (RMR Generation)	Generation that the ISO determines is required to be on line to meet Applicable Reliability Criteria requirements. This includes i) Generation constrained on line to meet NERC and WECC reliability criteria for interconnected systems operation; ii) Generation needed to meet Load demand in constrained areas; and iii) Generation needed to be operated to provide voltage or security support of the ISO or a local area.
Reliability Must-Run Unit (RMR Unit)	A Generating Unit which is the subject of a Reliability Must-Run Contract.
Reliability Upgrade	The transmission facilities, other than Direct Assignment Facilities, beyond the first point of interconnection necessary to interconnect a New Facility safely and reliably to the ISO Controlled Grid, which would not have been necessary but for the interconnection of a New Facility, including network upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of a New Facility to the ISO Controlled Grid. Reliability Upgrades also include, consistent with WECC practice, the facilities necessary to mitigate any adverse impact a New Facility's interconnection may have on a path's WECC path rating.
REMnet	The Wide Area Network through which the ISO acquires Meter Data.

Replacement Reserve	Generating capacity that is dedicated to the ISO, capable of starting up if not already operating, being synchronized to the ISO Controlled Grid, and Ramping to a specified operating level within a sixty (60) minute period, the output of which can be continuously maintained for a two hour period. Also, Curtailable Demand that is capable of being curtailed within sixty minutes and that can remain curtailed for two hours.
Request for Expedited Interconnection Procedures	A written request, submitted pursuant to Section 5.7.3.1.1 of the ISO Tariff, by which a New Facility Operator can request expedited processing of its Interconnection Application.
Resource-Specific Settlement Interval Ex Post Price	The Resource-Specific Settlement Interval Ex Post Price will equal the Energy-weighted average of the applicable Dispatch Interval Ex Post Prices for each Settlement Interval taking into account each resource's Instructed Imbalance Energy, except Regulation Energy. The Resource-Specific Settlement Interval Ex Post Price shall apply to those resources that are capable of responding to ISO Dispatch Instructions.

Responsible Utility	The utility which is a party to the TCA in whose Service Area the Reliability Must-Run Unit is located or whose Service Area is contiguous to the Service Area in which a Reliability Must-Run Unit owned by an entity outside of the ISO Controlled Grid is located.
Revenue Requirement	The revenue level required by a utility to cover expenses made on an investment, while earning a specified rate of return on the investment.
Revised Adjusted RMR Invoice	The monthly invoice issued by the RMR Owner to the ISO pursuant to the RMR Contract reflecting any appropriate revisions to the Adjusted RMR Invoice based on the ISO's validation and actual data for the billing month.
Revised Estimated RMR Invoice	The monthly invoice issued by the RMR Owner to the ISO pursuant to the RMR Contract reflecting appropriate revisions to the Estimated RMR Invoice based on the ISO's validation of the Estimated RMR Invoice.
Revised Schedule	A Schedule submitted by a Scheduling Coordinator to the ISO following receipt of the ISO's Suggested Adjusted Schedule.
RMR Owner	The provider of services under a Reliability Must-Run Contract.
Real-Time Dispatch (RTD) Software	The security constrained optimal dispatch and ex post pricing software used by the ISO to determine which Ancillary Service and Supplementary Energy resources to Dispatch and to calculate the Ex Post Prices.
SCADA (Supervisory Control and Data Acquisition)	A computer system that allows an electric system operator to remotely monitor and control elements of an electric system.

SC Application Form	The form specified by the ISO from time to time in which an SC Applicant must apply to the ISO for certification as a Scheduling Coordinator.
Scaled Marginal Loss Rate	A factor calculated by the ISO for a given Generator location for each hour by multiplying the Full Marginal Loss Rate for such Generator location by the Loss Scale Factor for the relevant hour.
Schedule	A statement of (i) Demand, including quantity, duration and Take-Out Points and (ii) Generation, including quantity, duration, location of Generating Unit, and Transmission Losses; and (iii) Ancillary Services which will be self-provided, (if any) submitted by a Scheduling Coordinator to the ISO. "Schedule" includes Preferred Schedules, Suggested Adjusted Schedules, Final Schedules and Revised Schedules.
Scheduled Maintenance	Maintenance on Participating Generators, TOs and UDC facilities scheduled more than twenty-four hours in advance.
Scheduling Coordinator	An entity certified by the ISO for the purposes of undertaking the functions specified in Section 2.2.6 of the ISO Tariff.
Scheduling Coordinator Metered Entity or SC Metered Entity	A Generator, Eligible Customer or End-User that is not an ISO Metered Entity.

Scheduling Point	A location at which the ISO Controlled Grid is connected, by a group of transmission paths for which a physical, non-simultaneous transmission capacity rating has been established for Congestion Management, to transmission facilities that are outside the ISO's Operational Control. A Scheduling Point typically is physically located at an "outside" boundary of the ISO Controlled Grid (e.g., at the point of interconnection between a Control Area utility and the ISO Controlled Grid). For most practical purposes, a Scheduling Point can be considered to be a Zone that is outside the ISO's Controlled Grid.
Security Monitoring	The real-time assessment of the ISO Controlled Grid that is conducted to ensure that the system is operating in a secure state, and in compliance with all Applicable Reliability Criteria.
Service Area	An area in which an IOU or a Local Publicly Owned Electric Utility is obligated to provide electric service to End-Use Customers.
Set Point	Scheduled operating level for each Generating Unit or other resource scheduled to run in the Hour-Ahead Schedule.

Severance Fee	The charge or periodic charge assessed to customers to recover the reasonable uneconomic portion of costs associated with Generation-related assets and obligations, nuclear decommissioning, and capitalized Energy efficiency investment programs approved prior to August 15, 1996 and as defined in the California Assembly Bill No. 1890 approved by the Governor on September 23, 1996.
Scheduling and Logging system for the ISO of California (SLIC)	A logging application that allows Market Participants to notify the ISO when a unit's properties change due to physical problems. Users can modify the maximum and minimum output of a unit, as well as the ramping capability of the unit.
Spinning Reserve	The portion of unloaded synchronized generating capacity that is immediately responsive to system frequency and that is capable of being loaded in ten minutes, and that is capable of running for at least two hours.
Standard Ramp (-ing)	A ramp calculated from two consecutive Final Hour Ahead Schedules that results in a straight trajectory between 10 minutes before the start of an operating hour to 10 minutes after the start of the operating hour
Standby Rate	A rate assessed a Standby Service Customer by the Participating TO that also provides retail electric service, as approved by the Local Regulatory Authority, or FERC, as applicable, for Standby Service which compensates the Participating TO, among other things, for costs of High Voltage Transmission Facilities.

Start-Up Fuel Cost Charge	The charge determined in accordance with Section 2.5.23.3.7.
Start-Up Fuel Cost Demand	The level of Demand specified in Section 2.5.23.3.7.3.
Start-Up Fuel Cost Invoice	The invoice submitted to the ISO in accordance with Section 2.5.23.3.7.6.
Start-Up Fuel Cost Trust Account	The trust account established in accordance with Section 2.5.23.3.7.2.
Start-Up Fuel Costs	The cost of the fuel consumed by a particular Generating Unit from the time of first fire, the time of receipt of an ISO Dispatch instruction, or the time the unit was last synchronized to the grid, whichever is later, until the time the generating unit is synchronized or re-synchronized to the grid and producing Energy. Start-Up Fuel Costs are determined by multiplying the actual amount of fuel consumed by the proxy gas price as determined in accordance with Section 2.5.23.3.4 at the time the fuel is consumed.

Suggested Adjusted Schedule The output of the ISO's initial Congestion Management for each Scheduling Coordinator for the Day-Ahead Market ("Suggested Adjusted Day-Ahead Schedule") or for the Hour-Ahead Market ("Suggested Adjusted Hour-Ahead Schedule"). These Schedules will reflect ISO suggested adjustments to each Scheduling Coordinator's Preferred Schedule to resolve Inter-Zonal Congestion on the ISO Controlled Grid, based on the Adjustment Bids submitted. These Schedules will be balanced with respect to Generation, Transmission Losses, Load, and trades between Scheduling Coordinators to resolve Inter-Zonal Congestion.

Supplemental Energy Energy from Generating Units bound by a Participating Generator Agreement, Loads bound by a Participating Load Agreement, System Units, and System Resources which have uncommitted capacity following finalization of the Hour-Ahead Schedules and for which Scheduling Coordinators have submitted bids to the ISO at least half an hour before the commencement of the Settlement Period.

Supply The rate at which Energy is delivered to the ISO Controlled Grid measured in units of watts or standard multiples thereof, e.g., 1,000W=1 KW; 1,000 KW = 1MW, etc.

System Emergency Conditions beyond the normal control of the ISO that affect the ability of the ISO Control Area to function normally including any abnormal system condition which requires immediate manual or automatic action to prevent loss of Load, equipment damage, or tripping of system elements which might result in cascading Outages or to restore system operation to meet the minimum operating reliability criteria.

System Impact Study An engineering study conducted to determine whether a New Facility Operator's request for interconnection to the ISO Controlled Grid would require new transmission additions, upgrades or other mitigation measures.

System Planning Studies Reports summarizing studies performed to assess the adequacy of the ISO Controlled Grid as regards conformance to Reliability Criteria.

System Reliability A measure of an electric system's ability to deliver uninterrupted service at the proper voltage and frequency.

System Resource A group of resources located outside of the ISO Control Area capable of providing Energy and/or Ancillary Services to the ISO Controlled Grid.

System Unit One or more individual Generating Units and/or Loads within a Metered Subsystem controlled so as to simulate a single resource with specified performance characteristics, as mutually determined and agreed to by the MSS Operator and the ISO. The Generating Units and/or Loads making up a System Unit must be in close physical proximity to each other such that the operation of the resources comprising the System Unit does not result in significant differences in flows on the ISO Controlled Grid.

Take-Out Point	The metering points at which a Scheduling Coordinator Metered Entity or ISO Metered Entity takes delivery of Energy.
Tax Exempt Debt	Municipal Tax Exempt Debt or Local Furnishing Bonds.
Tax Exempt Participating TO	A Participating TO that is the beneficiary of outstanding Tax Exempt Debt issued to finance any electric facilities, or rights associated therewith, which are part of an integrated system including transmission facilities the Operational Control of which is transferred to the ISO pursuant to the TCA.
TCA (Transmission Control Agreement)	The agreement between the ISO and Participating TOs establishing the terms and conditions under which TOs will become Participating TOs and how the ISO and each Participating TO will discharge their respective duties and responsibilities, as may be modified from time to time.
Tie Point Meter	A revenue meter, which is capable of providing Settlement Quality Meter Data, at a Scheduling Point or at a boundary between UDCs within the ISO Controlled Grid.
TO (Transmission Owner)	An entity owning transmission facilities or having firm contractual rights to use transmission facilities.
TO Tariff	A tariff setting out a Participating TO's rates and charges for transmission access to the ISO Controlled Grid and whose other terms and conditions are the same as those contained in the document referred to as the Transmission Owners Tariff approved by FERC as it may be amended from time to time.
Tolerance Band	The tolerance band expressed in terms of Energy (MWh) for the performance requirement for Generating Units and System Units for each Settlement Interval will equal the greater of the absolute value of: 1) 5 MW divided by number of Settlement Intervals per Settlement Period or 2) three percent

Transition Charge	The component of the Access Charge collected by the ISO with the High Voltage Access Charge in accordance with Section 5.7 of Appendix F, Schedule 3.
Transition Period	The period of time established by the California Legislature and CPUC to allow IOUs and Local Publicly Owned Electric Utilities an opportunity to recover Transition Costs or Severance Fees.
Transmission Losses	Energy that is lost as a natural part of the process of transmitting Energy from Generation to Load delivered at the ISO/UDC boundary or Control Area boundary.
Transmission Revenue Credit	For an Original Participating TO, the proceeds received from the ISO for Wheeling service, FTR auction revenue and Usage Charges, plus the shortfall or surplus resulting from any cost differences between Transmission Losses and Ancillary Service requirements associated with Existing Rights and the ISO's rules and protocols. For a New Participating TO during the 10-year transition period described in Section 4 of Schedule 3 of Appendix F, the proceeds received from the ISO for Wheeling service and Net FTR Revenue, plus the shortfall or surplus resulting from any cost differences between Transmission Losses and Ancillary Service requirements associated with Existing Rights and the ISO's rules and protocols. After the 10-year transition period, the New Participating TO Transmission

Unaccounted for Energy (UFE)	UFE is the difference in Energy, for each utility Service Area and Settlement Period, between the net Energy delivered into the utility Service Area, adjusted for utility Service Area Transmission Losses (calculated in accordance with Section 7.4.2), and the total metered Demand within the utility Service Area adjusted for distribution losses using Distribution System loss factors approved by the Local Regulatory Authority. This difference is attributable to meter measurement errors, power flow modeling errors, energy theft, statistical Load profile errors, and distribution loss deviations.
Uncontrollable Force	Any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm, flood, earthquake, explosion, any curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities or any other cause beyond the reasonable control of the ISO or Market Participant which could not be avoided through the exercise of Good Utility Practice.
Uninstructed Deviation Penalty	The penalty as set forth in Section 11.2.4.1.2 of this ISO Tariff.
Uninstructed Imbalance Energy	The real-time change in Generation or Demand other than that instructed by the ISO or which the ISO Tariff provides will be paid at the price for Uninstructed Imbalance Energy.
Unit Commitment	The process of determining which Generating Units will be committed (started) to meet Demand and provide Ancillary Services in the near future (e.g., the next Trading Day).
Usage Charge	The amount of money, per 1 kW of scheduled flow, that the ISO charges a Scheduling Coordinator for use of a specific Congested Inter-Zonal Interface during a given hour.

Voltage Limits	For all substation busses, the normal and post-contingency Voltage Limits (kV). The bandwidth for normal Voltage Limits must fall within the bandwidth of the post-contingency Voltage Limits. Special voltage limitations for abnormal operating conditions such as heavy or light Demand may be specified.
Voltage Support	Services provided by Generating Units or other equipment such as shunt capacitors, static var compensators, or synchronous condensers that are required to maintain established grid voltage criteria. This service is required under normal or System Emergency conditions.
Waiver Denial Period	The period determined in accordance with Section 5.11.6.
Warning Notice	A Notice issued by the ISO when the operating requirements for the ISO Controlled Grid are not met in the Hour-Ahead Market, or the quantity of Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve and Supplemental Energy available to the ISO does not satisfy the Applicable Reliability Criteria.
WEnet (Western Energy Network)	An electronic network that facilitates communications and data exchange among the ISO, Market Participants and the public in relation to the status and operation of the ISO Controlled Grid.
Wheeling	Wheeling Out or Wheeling Through.
Wheeling Access Charge	The charge assessed by the ISO that is paid by a Scheduling Coordinator for Wheeling in accordance with Section 7.1. Wheeling Access Charges shall not apply for Wheeling under a bundled non-economy Energy coordination agreement of a Participating TO executed prior to July 9, 1996. The Wheeling Access Charge may consist of a High Voltage Wheeling Access Charge and a Low Voltage Wheeling Access Charge.

Wheeling Out	Except for Existing Rights exercised under an Existing Contract in accordance with Sections 2.4.3 and 2.4.4, the use of the ISO Controlled Grid for the transmission of Energy from a Generating Unit located within the ISO Controlled Grid to serve a Load located outside the transmission and Distribution System of a Participating TO.
Wheeling Through	Except for Existing Rights exercised under an Existing Contract in accordance with Sections 2.4.3 and 2.4.4, the use of the ISO Controlled Grid for the transmission of Energy from a resource located outside the ISO Controlled Grid to serve a Load located outside the transmission and Distribution System of a Participating TO.
Wholesale Customer	A person wishing to purchase Energy and Ancillary Services at a Bulk Supply Point or a Scheduling Point for resale.
Wholesale Sales	The sale of Energy and Ancillary Services at a Bulk Supply Point or a Scheduling Point for resale.
WSCC (Western System Coordinating Council)	The Western Systems Coordinating Council or its successor, the WECC.
WECC (Western Electricity Oversight Council)	The Western Electricity Coordinating Council or its successor.
WSCC Reliability Criteria Agreement	The Western Systems Coordinating Council Reliability Criteria Agreement dated June 18, 1999 among the WSCC and certain of its Member transmission operators, as such may be amended from time to time.
Zone	A portion of the ISO Controlled Grid within which Congestion is expected to be small in magnitude or to occur infrequently. "Zonal" shall be construed accordingly.

Day-Aead Schedule Timeline

	Responsible Parties					
Line	**Time (Before or on)**	**ISO**	**SCs**	**Must-Take and Reliability generation**	**UDC**	**Actions**
	Two days ahead					
0	6:00 PM	x				Publish forecasted transmission conditions (Generator Meter Multipliers, system load forecast (by Zones), estimated Ancillary Service requirements, scheduled transmission Outages, Loop Flows, congestion, ATC, etc.)
	One day ahead					
1	5:00 AM	X				Notify Scheduling Coordinators of unit-specific Reliability Must Run requirements
2	6:00 AM	x				Update system load forecast and Ancillary Service requirements.
3			X			Notify ISO of price option for Reliability Must-Run Units for which notification was provided at 5:00 a.m.
4			x			Provide direct access load forecasts to the ISO.
5	6:30 AM	x				Provide net direct access load forecasts to UDCs.
6[not used]						
7 [not used]						
8 [not used]						
9 [not used]						
10			x			Submit initial preferred energy schedules to the ISO.
11			x			Submit Ancillary Service bids and/or self-provided Ancillary Service schedules to the ISO.
12	10:00 AM	x				Validate all SC energy schedules, including RMR requirements, and bids; notify and resolve incorrect schedules and bids, if any.

13		x				Validate all SC Ancillary Service schedules and bids; notify and resolve incorrect Ancillary Service schedules and bids, If any.
14		x				Start the Inter-Zonal Congestion Management evaluation process and Ancillary Services bid evaluation.
15	11:00 AM	x				If no Inter-Zonal Congestion exists, go to line 27.
16		x				Complete advisory dispatch schedules and transmission prices if Inter-Zonal Congestion exists.
17		x				Complete the advisory schedules and prices of each Ancillary Service.
18		x				Notify all SC if Inter-Zonal Congestion exists. Publish advisory transmission prices.
19		x				Inform all SCs their advisory dispatch schedules if Inter-Zonal Congestion exists.
20		x				Inform all SCs advisory AS schedules and prices if Inter-Zonal Congestion exists.
21	11:05 PM		x			Start the process of developing revised schedules and price bids.
22			x			Start the process of developing revised AS schedules and price bids.
23	12:00 PM		x			Submit revised Preferred Schedules and price bids to the ISO.
24			x			Submit revised preferred AS schedules and price bids to the ISO.
25	12:00 PM	x				Validate all SC schedules and bids; notify and resolve incorrect schedules and bids, if any.
26		x				Validate all SC AS schedules and bids; notify and resolve incorrect schedules and bids, if any.
27		x				Start the Inter-Zonal Congestion Management evaluation process and Ancillary Services bid evaluation.

28	1:00 PM	x				Complete final dispatch schedules and transmission prices.
29		x				Complete Final Schedules and prices of each Ancillary Service.
30	1:00 PM	x				Complete Final Schedules.
31	1:00 PM	x				Inform all SCs their final dispatch schedules.
32		x				Inform all SCs their final AS schedules and prices.
33		x				Publish transmission prices if Inter-Zonal Congestion exists.
34		x				Calculate and communicate with SC the specific SCs Zonal prices if asked.
35 [not used]						
36 [not used]						
37 [not used]						
38		x				Develop net schedules for each of the Control Area interfaces. These interfaces include SC net schedules, Control Area net schedules and/or individual transactions.
39		x				Call each adjacent Control Area and check that net schedules at each interface point match. Search for discrepancies and identify transactions that do not match. Resolve discrepancies with the involved SCs or eliminate the transactions with discrepancies.

Black Start Units

The following requirements must be met by Generating Units providing Black Start ("Black Start Units"):

(a) Black Start Units must be capable of starting and paralleling with the ISO Controlled Grid without aid from the ISO Controlled Grid;

(b) Black Start Units must be capable of making a minimum number of starts per event (to be without aid from the ISO Controlled Grid as determined by the ISO);

(c) Black Start Units must be equipped with governors capable of operating in the stand alone (asynchronous) and parallel (synchronous) modes.

(d) Black Start Units must have startup load pickup capabilities at a level to be determined by the ISO, including total startup load (MW) and largest startup load (MW) for such power output levels as the ISO may specify.

(e) All Black Start Units must be capable of producing Reactive Power (boost) and absorbing Reactive Power (buck) as required by the ISO to control system voltages. This requirement may be met by the operation of more than one Black Start Unit in parallel providing that:

(i) the Black Start generation supplier demonstrates that the proposed Generation resource shares reactive burden equitably;

(ii) all Participating Generators associated with the proposed Black Start source are located in the same general area.

Buck/boost capability requirement shall be dependent on the location of the proposed resource in relation to Black Start load.

(f) All Black Start Units must have the following communication/control requirements:

(i) dial-up telephone;

(ii) backup radio;

(iii) manning levels which accord with Good Utility Practice.

In response to an invalid schedule or bid, the Scheduling Coordinator shall be given a period of time to respond to the notification. The Scheduling Coordinator shall respond by resubmitting a corrected schedule or bid. If the Scheduling Coordinator does not respond to the notification within the required time frame, the ISO shall proceed without that Scheduling Coordinator's bid or schedule.

5. Treatment of Missing Values.

5.1 Missing Location Values. Any bid submitted without a Location Code shall be deemed to have a zero bid quantity for that Settlement Period.

5.2 Missing Quantity Values. Any bid submitted without a quantity value shall be deemed to have a zero bid quantity for Ancillary Service capacity for that Settlement Period.

5.3 Missing Price Values. Any bid submitted with non-zero quantity value, but with a missing price value, shall be rejected.

6. Treatment of Equal Price Bids. The ISO shall allow these Scheduling Coordinators to resubmit, at their own discretion, their bid no later than 2 hours the same day the original bid was submitted. In the event identical prices still exist following resubmission of bids, the ISO shall determine the merit order for each Ancillary Service by considering applicable constraint information for each Generating Unit, Load or other resource, and optimize overall costs for the Trading Day. If equal bids still remain, the ISO shall proportion participation in the Final Day-Ahead or Hour-Ahead Schedule (as the case may be) amongst the bidding Generating Units, Loads and resources with identical bids to the extent permitted by operating constraints and in a manner deemed appropriate by the ISO.

7. Receipt of Bids and Schedules. The ISO shall maintain an audit trail relating to the receipt of bids and schedules and the processing of those bids and schedules.

Schedule 1

Grid Management Charge

Part A – Monthly Calculation of Grid Management Charge (GMC)

The Grid Management Charge consists of seven separate service charges: (1) the Core Reliability Services Charge, (2) the Energy Transmission Services Net Energy Charge, (3) the Energy Transmission Services Uninstructed Deviations Charge, (4) the Forward Scheduling Charge, (5) the Congestion Management Charge, (6) the Market Usage Charge, and (7) the Settlements, Metering, and Client Relations Charge.

1. The rate in $/MW for the Core Reliability Services Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total of the forecasted Scheduling Coordinators' metered non-coincident peak hourly demand in MW for all months during the year.

2. The rate in $/MWh for the Energy Transmission Services Net Energy Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecast Metered Control Area Load in MWh.

3. The rate in $/MWh for the Energy Transmission Services Uninstructed Deviations Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the absolute value of total annual forecast net uninstructed deviations (netted within a Settlement Interval) in MWh.

4. The rate in $ per Schedule for the Forward Scheduling Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecast number of non-zero MW Final Hour-Ahead Schedules, including all awarded Ancillary Service bids.

5. The rate in $/MWh for the Congestion Management Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecast Scheduling Coordinators' inter-zonal scheduled flow (excluding flows pursuant to Existing Contracts) per path in MWh.

6. The rate in $/MWh for the Market Usage Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecast total purchases and sales (including out-of-market transactions) of Ancillary Services, Supplemental Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with uninstructed deviations being netted by Settlement Interval) in MWh.

7. The rate for the Settlements, Metering, and Client Relations Charge will be fixed at $500.00 per month, per Scheduling Coordinator Identification Number ("SC ID") with an invoice value other than $0.00 in the current trade month.

The rates for the foregoing charges shall be adjusted automatically each year, effective January 1 for the following twelve months, in the manner set forth in Part D of this Schedule.

Part B – Quarterly Adjustment, If Required

Each component rate of the Grid Management Charge will be adjusted automatically on a quarterly basis, up or down, so that rates reflect the annual revenue requirement as stated in the ISO's annual informational filing, if the estimated billing determinant volumes for that component, on an annual basis, change by 5% or more during the year. Such adjustment may be implemented not more than once per calendar quarter, and will be effective the first day of the next calendar month.

The rates will be adjusted in accordance with the following formula:

According to the formulae listed in Appendix F, Schedule 1, Part A with the billing determinant(s) readjusted on a going-forward basis to reflect the 5% or greater change from the estimated billing determinant provided in the annual informational filing.

Part C – Costs Recovered through the GMC

As provided in Section 8 of the ISO Tariff, the Grid Management Charge includes the following costs, as projected in the ISO's budget for the year to which the Grid Management Charge applies:

- Operating costs (as defined in Section 8.2.2)
- Financing costs (as defined in Section 8.2.3), including Start-Up and Development costs and
- Operating and Capital Reserve costs (as defined in Section 8.2.4)

Such costs, for the ISO as a whole, are allocated to the seven service charges that comprise the Grid Management Charge: (1) Core Reliability Services Charge, (2) Energy Transmission Services Net Energy Charge, (3) Energy Transmission Services Uninstructed Deviations Charge, (4) Forward Scheduling Charge, (5) Congestion Management Charge, (6) Market Usage Charge, and (7) Settlements, Metering, and Client Relations Charge, according to the factors listed in Part E of this Schedule 1, and

adjusted annually for:

- any surplus revenues from the previous year as deposited in the Operating and Capital Reserve Account, as defined under Section 8.5, or deficiency of revenues, as recorded in a memorandum account;

divided by:

- forecasted annual billing determinant volumes;

adjusted quarterly for:

- a change in the volume estimate used to calculate the individual Grid Management Charge components, if, on an annual basis, the change is 5% or more.

The Grid Management Charge revenue requirement formula is as follows:

Grid Management Charge revenue requirement =

- Operating Expenses + Debt Service + [(Coverage Requirement x Senior Lien Debt Service) and/or (Cash Funded Capital Expenditures)] - Interest Earnings - Other Revenues - Reserve Transfer

Where,

- **Operating Expenses** = O&M Expenses plus Taxes Other Than Income Taxes and Penalties

- **O&M Expenses** = Transmission O&M Expenses (Accounts 560-574) plus Customer Accounting Expenses (Accounts 901-905) plus Customer Service and Informational Expenses (Accounts 906-910) plus Sales Expenses (Accounts 911-917) plus Administrative & General Expenses (Accounts 920-935)
- **Taxes Other Than Income Taxes =** those taxes other than income taxes which relate to ISO operating income (Account 408.1)
- **Penalties** = payments by the ISO for penalties or fines incurred for violation of WECC reliability criteria (Account 426.3)
- **Debt Service** = for any fiscal year, scheduled principal and interest payments, sinking fund payments related to balloon maturities, repayment of commercial paper notes, net payments required pursuant to a payment obligation, or payments due on any ISO notes. This amount includes the current year accrued principal and interest payments due in April of the following year.
- **Coverage Requirement** = 25% of the Senior Lien Debt Service.
- **Senior Lien Debt Service** = all Debt Service that has a first lien on ISO Net Operating Revenues (Account 128 subaccounts).
- **Cash Funded Capital Expenditures** = Post current fiscal year capital additions (Accounts 301-399) funded on a pay-as-you-go basis.
- **Interest Earnings** = Interest earnings on Operating and Capital Reserve balances (Account 419). Interest on bond or note proceeds specifically designated for capital projects or capitalized interest is excluded.
- **Other Revenues** = Amounts booked to Account 456 subaccounts. Such amounts include but are not limited to application fees, WECC reliability coordinator reimbursements, and fines assessed and collected by the ISO.
- **Reserve Transfer** = the projected reserve balance for December 31 of the prior year less the Reserve Requirement as adopted by the ISO Governing Board and FERC. If such amount is negative, the amount may be divided by two, so that the reserve is replenished within a two-year period. (Account 128 subaccounts)
- **Reserve Requirement** = 15% of Annual Operating Expenses.

A separate revenue requirement shall be established for each component of the Grid Management Charge by developing the revenue requirement for the ISO as a whole and then assigning such costs to the seven service categories using the allocation factors provided in Appendix F, Schedule 1, Part E of this Tariff.

Part D – Information Requirements

Budget Schedule

The ISO Governing Board shall set forth a budget schedule that shall specify the dates for the budget posting and public workshop events noted below and other significant budget related milestones providing an opportunity for public input.

Budget Posting

The ISO will post on its Internet site the preliminary proposed ISO operating and capital budget to be effective during the subsequent fiscal year, and the projected billing determinant volumes used to develop the rate for each component of the Grid Management Charge.

Public Workshop

Subsequent to the website posting, and prior to (i) the ISO Governing Board approval of the budget and (ii) the submission of the informational filing described in the next paragraph of this Part D, the ISO shall hold a public budget workshop where it will provide an overview of and answer questions from stakeholders on the proposed budget, cost allocation, and the charges for each of the ISO's services for the following year.

Annual Informational Filing

The ISO will make a filing each year no later than December 15, or the first Business Day thereafter, at FERC that shall contain projected cost data on the ISO presented in conformance with the budget approved by the ISO Governing Board and the FERC Uniform System of Accounts (USOA). This filing shall contain such information as is required to update the GMC rates resulting from the application of the formulae in Part A of this Schedule for the following calendar year.

Periodic Financial Reports

The ISO will create periodic financial reports consisting of an income statement, balance sheet, statement of operating reserves, and such other reports as are required by the ISO Governing Board. The periodic financial reports will be posted on the ISO's Website not less than quarterly.

1558	Transmission Maintenance	58%	42%	0%	0%	0%	0%	100%
1559	Operations Application Support	60%	40%	0%	0%	0%	0%	100%
1561	Operations Engineering South	65%	35%	0%	0%	0%	0%	100%
1562	Operations Engineering North	55%	45%	0%	0%	0%	0%	100%
1563	Operations Coordination	75%	25%	0%	0%	0%	0%	100%
1564	Operations Scheduling	100%	0%	0%	0%	0%	0%	100%
1565	Pre-Scheduling and Support	77%	23%	0%	0%	0%	0%	100%
1566	Regional Coordination - General	100%	0%	0%	0%	0%	0%	100%
1600	**Legal and Regulatory Division**	**36%**	**22%**	**4%**	**7%**	**17%**	**15%**	**100%**
1611	VP General Counsel - General	36%	22%	4%	7%	17%	15%	100%
1631	Legal and Regulatory	44%	22%	4%	5%	10%	16%	100%
1641	Market Analysis	15%	26%	0%	20%	31%	7%	100%
1642	Market Surveillance Committee	25%	25%	0%	25%	25%	0%	100%
1651	ISO Governing Board	44%	22%	4%	5%	10%	16%	100%
1661	Compliance - General	22%	20%	12%	0%	29%	17%	100%
1662	Compliance - Audits	8%	0%	0%	0%	50%	42%	100%
1700	**Market Services Division**	**17%**	**2%**	**9%**	**9%**	**20%**	**41%**	**100%**
1711	VP Market Services - General	17%	2%	9%	9%	20%	41%	100%
1721	Billing and Settlements-General	25%	0%	0%	0%	0%	75%	100%
1722	Business Development Support	0%	0%	0%	0%	0%	100%	100%
1723	RMR Settlements	80%	20%	0%	0%	0%	0%	100%
1724	BBS - PSS	0%	0%	0%	0%	0%	100%	100%
1725	BBS - FSS	0%	0%	0%	0%	0%	100%	100%
1731	Contracts and Special Projects	43%	7%	0%	0%	0%	50%	100%
1741	Client Relations	0%	0%	0%	0%	0%	100%	100%
1751	Market Operations - General	31%	0%	15%	15%	35%	4%	100%
1752	Manager of Markets	27%	5%	27%	22%	18%	0%	100%
1753	Market Engineering	21%	0%	0%	28%	43%	7%	100%
1755	Business Solutions	6%	0%	47%	12%	29%	6%	100%
1756	Market Quality - General	0%	0%	0%	0%	71%	29%	100%
1757	Market Integration	7%	0%	30%	30%	26%	7%	100%

Schedule 2

Other Charges

Voltage Support Service

The user rate per unit of purchased Voltage Support will be calculated in accordance with the formula in ISO Tariff Section 2.5.28.5.

Regulation Service

Regulation Obligation:

The amount of Regulation required will be calculated in accordance with Section 4.1 of the Ancillary Services Requirements Protocol (ASRP).

Regulation Rates:

The formulas for calculating the amount of and charges for Regulation Service are referenced in ISO Tariff Sections 2.5.20.1, 2.5.27, and 2.5.28.

The ISO will calculate the user rate for Regulation in each Zone for each Settlement Period in accordance with Section 2.5.28.1.

Spinning Reserve Service

Spinning Reserve Obligation:

The amount of Spinning Reserve required as a component of Operating Reserves is specified in Section 5.1 of the Ancillary Services Requirements Protocol (ASRP).

Spinning Reserve Rates:

The formulas for calculating the amount of and charges for Spinning Reserve Service are referenced in ISO Tariff Sections 2.5.27.2, 2.5.28.2.

The ISO will calculate the user rate for Spinning Reserve in each Zone for each Settlement Period in accordance with ISO Tariff Section 2.5.28.2.

Non-Spinning Reserve Service

Non-Spinning Reserve Obligation:

The amount of Non-Spinning Reserve required as a component of Operating Reserves is specified in Section 5.1 of the Ancillary Services Requirements Protocol (ASRP).

Non-Spinning Reserve Rates:

The formulas for calculating the amount of and charges for Non-Spinning Reserve Service are referenced in ISO Tariff Sections 2.5.27.3, 2.5.28.3.

The ISO will calculate the user rate for Non-Spinning Reserve in each Zone for each Settlement Period in accordance with ISO Tariff Section 2.5.28.3.

Replacement Reserves

The formulas for calculating the amount of and charges for Replacement Reserve Service are referenced in ISO Tariff Sections 2.5.27.4 and 2.5.28.4.

Black Start Capability

The user rate per unit of purchased Black Start capability for each Settlement Period will be calculated in accordance with ISO Tariff Section 2.5.28.6.

3.7 If the Imperial Irrigation District or an entity outside the State of California should apply to become a Participating TO, the ISO Governing Board will review the reasonableness of integrating the entity into one of the existing TAC Areas. If the entity cannot be integrated without the potential for significant cost shifts, the ISO Governing Board may establish a separate TAC Area.

4. Transition Date

4.1 New Participating TOs shall provide the ISO with a notice of intent to join and execute the Transmission Control Agreement by either January 1 or July 1 of any year and provide the ISO with an application within 15 days of such notice of intent.

4.2 The transition shall begin on either January 1 or July 1 after the date the first New Participating TO's execution of the Transmission Control Agreement takes effect (Transition Date). The Transition Date shall be the same for the Northern Area, East Central Area and the Southern Area. The Transition Date shall also be the same for the West Central Area, should it come into existence in accordance with Section 3.2 of this Schedule 3, unless the ISO provides additional information demonstrating the need for a deferral. The 10-year transition defined in Section 5.8 of Schedule 3 shall start from that date. If the West Central TAC Area is created after the Transition Date, the applicable High Voltage Access Charge shall transition to an ISO Grid-wide High Voltage Access Charge over the period remaining from the Transition Date, on the same schedule as the other TAC Areas.

4.3 **Application to Additional TAC Areas.** For any TAC Areas other than those specified in Section 4.2 of this Schedule 3, created after the Transition Date, including any TAC Area created as a result of the application of Section 3.7 of this Schedule 3, whether and over what period the applicable High Voltage Access Charge shall transition to an ISO Grid-wide charge shall be determined by the ISO Governing Board.

4.4 **Application to Wheeling Access Charges.** The transition described in this Section 4 shall also apply, on the same schedule, to High Voltage Wheeling Access Charges.

4.5 **Conversion of Existing Rights.** During the process by which a New Participating TO executes the Transmission Control Agreement, the ISO and potential New Participating TO that has an obligation to serve Load shall determine the amount of FTRs to be allocated to the New Participating TO for each Existing Right that the New Participating TO converts to Converted Rights. In making that determination, the ISO will consider the amount of contracted transmission capacity, the firmness of the contracted transmission capacity, and other characteristics of the contracted

transmission capacity to determine the amount of FTRs to be given to the New Participating TO in accordance with Section 9.4.3 of the ISO Tariff.

5. Determination of the Access Charge.

5.1 The Access Charge consists of a High Voltage Access Charge (HVAC) that is based on a TAC Area component and an ISO Grid-wide component, a Transmission Charge, and a Low Voltage Access Charge (LVAC) that is based on a utility-specific rate established by each Participating TO in accordance with its TO Tariff.

5.2 Each Participating TO will develop, in accordance with Section 6 of this Schedule 3, a High Voltage Transmission Revenue Requirement ($HVTRR_{PTO}$) consisting of a Transmission Revenue Requirement for Existing High Voltage Facility ($EHVTRR_{PTO}$) and a Transmission Revenue Requirement for New High Voltage Facility ($NHVTRR_{PTO}$). The $HVTRR_{PTO}$ includes the TRBA adjustment described in Section 6.1 of this Schedule 3.

5.3 The Gross Load amount in MWh shall be established by each Participating TO and filed at FERC with each Participating TO's Transmission Revenue Requirement (GL_{PTO}).

5.4 The HVAC applicable to each UDC and MSS in a PTO Service Area and Scheduling Coordinator serving Demand in the PTO Service Area, shall be based on a TAC Area component ($HVAC_A$) and an ISO Grid-wide component ($HVAC_I$).

$$HVAC = HVAC_A + HVAC_I$$

5.5 The Existing Transmission Revenue Requirement for the TAC Area component ($ETRR_A$) is the summation of each Participating TO's $EHVTRR_{PTO}$ in that TAC Area. The Gross Load in the TAC Area (GL_A) is the summation of each Participating TO's Gross Load in that TAC Area (GL_{PTO}). The TAC Area component will be based on the product of Existing Transmission Revenue Requirement for the TAC Area ($ETRR_A$) and the applicable annual transition percentage (%TA) in Section 5.8 of this Schedule 3, divided by the Gross Load in the TAC Area (GL_A).

$$ETRR_A = \Sigma\, EHVTRR_{PTO}$$

$$GL_A = \Sigma\, GL_{PTO}$$

$$HVAC_A = (ETRR_A * \%TA) / GL_A$$

5.6 The Existing Transmission Revenue Requirement for the ISO Grid-wide component ($ETRR_I$) will be the summation of all TAC Areas' $ETRR_A$ multiplied by the applicable annual transition percentage (%IGW) in Section 5.8 of this Schedule 3. The New Transmission Revenue Requirement (NTRR) is the summation of each Participating TO's $NHVTRR_{PTO}$. The ISO Grid-wide component will be based on the $ETRR_I$ plus the NTRR, divided by the summation of all Gross Loads in the TAC Areas (GL_A).

$$ETRR_I = \Sigma\, ETRR_A * \%IGW$$

$$HVAC_I = (ETRR_I + NTRR) / \Sigma\, GL_A$$

The foregoing formulas will be adjusted, as necessary to take account of new TAC Areas.

(b) the annual high voltage TRBA adjustment shall be based on the principal balance in the high voltage TRBA as of September 30, which shall be calculated as a dollar amount based on the projected Transmission Revenue Credits as adjusted for the true up of the prior year's difference between projected and actual credits. For a Participating TO that is not a UDC, MSS or a Scheduling Coordinator serving End-Use Customers and that does not have Gross Load in its TO Tariff in accordance with Appendix F, Schedule 3, Section 9, the Participating TO shall include any over- or under-recovery of its annual High Voltage Transmission Revenue Requirement in its high voltage TRBA. If the annual high voltage TRBA adjustment involves only a partial year of operations, the Participating TO's over- or under-recovery shall be based on a partial year revenue requirement, calculated by multiplying the Participating TO's High Voltage Transmission Revenue Requirement by the number of days the High Voltage Transmission Facilities were under the ISO's Operational Control divided by the number of days in the year.

7 Limitation

(a) During each year of the transition period described in this Schedule 3, the increase in the total payment responsibility applicable to deliveries of Energy to Gross Loads in the PTO Service Area of an Original Participating TO attributable to the total for the year of (i) the amount applicable for the Original Participating TO under Section 8.6 of the ISO Tariff; plus (ii) the amount applicable to the implementation of the High Voltage Access Charge shall not exceed the amount specified in paragraph (b) of this section. This limitation shall be calculated individually for each Original Participating TO, provided that, if the net effect of clauses (i) and (ii) of this paragraph is positive for one or more Original Participating TOs for any year, the combined net effect shall be allocated among all Original Participating TOs in proportion to the amounts specified in paragraph (b) of this section. This limitation shall be applied by the ISO's calculation annually of amounts payable by New Participating TOs to Original Participating TOs such that the combined effect of clauses (i) and (ii) of this paragraph, and the payments received by each Original Participating TO shall not exceed the amounts specified in paragraph (b) of this section. The amount receivable by the Original Participating TO from the New Participating TOs to implement the limitation in paragraph (b) of this section, shall be credited through the Transition Charge established pursuant to Section 5.7 of this Schedule 3.

8. Updates to High Voltage Access Charges.

8.1 High Voltage Access Charges and High Voltage Wheeling Access Charges shall be adjusted: (1) on January 1 and July 1 of each year when necessary to reflect the addition of any New Participating TO and (2) on the date FERC makes effective a change to the High Voltage Transmission Revenue Requirements of any Participating TO. Using the High Voltage Transmission Revenue Requirement accepted or authorized by FERC, consistent with Section 9 of this Schedule 3, for each Participating TO, the ISO will recalculate on a monthly basis the High Voltage Access Charge and Transition Charge applicable during such period. Revisions to the Transmission Revenue Balancing Account adjustment shall be made effective annually on January 1 based on the principal balance in the TRBA as of September 30 of the prior year and a forecast of Transmission Revenue Credits for the next year.

8.2 For service provided by a Participating TO prior to the Transition Date, no refund ordered by FERC or amount accrued to that Participating TO's Transmission Revenue Balancing Account related to such service shall be reflected in the High Voltage Access Charge, Low Voltage Access Charge, the High Voltage Transmission Revenue Requirement, or the Low Voltage Transmission Revenue Requirement of a Participating TO. For service provided by a Participating TO following the Transition Date, any refund associated with a Participating TO's Transmission Revenue Requirement that has been accepted by FERC, subject to refund, shall be provided as ordered by FERC. Such refund shall be invoiced separately from the Market Invoice.

8.3 If the Participating TO withdraws one or more of its transmission facilities from the ISO Operational Control in accordance with Section 3.4 of the Transmission Control Agreement, then the ISO will no longer collect the TRR for that transmission facility through the ISO's Access Charge effective upon the date the transmission facility is no longer under the Operational Control of the ISO. The withdrawing Participating TO shall be obligated to provide the ISO will all necessary information to implement the withdrawal of the Participating TO's transmission facilities and to make any necessary filings at FERC to revise its TRR. The ISO shall revise its transmission Access Charge to reflect the withdrawal of one or more transmission facilities from ISO Operational Control.

9. Approval of Updated High Voltage Revenue Requirements

9.1 Participating TOs will make the appropriate filings at FERC to establish their Transmission Revenue Requirements for their Low Voltage Access Charges and the applicable High Voltage Access Charges, and to obtain approval of any changes thereto. All such filings with the FERC will include a separate appendix that states the HVTRR,

LVTRR (if applicable) and the appropriate Gross Load data and other information required by the FERC to support the Access Charges. The Participating TO will provide a copy of its filing to the ISO and the other Participating TOs in accordance with the notice provisions in the Transmission Control Agreement.

Methodology for Developing the Weighted Average Rate for Wheeling Service

The weighted average rate payable for Wheeling over joint facilities at each Scheduling Point shall be calculated as follows, applying the formula separately to the applicable Wheeling Access Charges:

$$\text{WBAC} = \sum\left(P_n \times \frac{Q_n}{\sum Q_n}\right)$$

Where:

WBAC	=	Weighted-average Wheeling Access Charge for each ISO Scheduling Point
P_n	=	The applicable Wheeling Access Charge rate for a TAC Area or Participating TO_n in $/kWh as set forth in Section 7.1.4 of the ISO Tariff and Section 5 of the TO Tariff.
Q_n	=	The Available Transfer Capacity (in MW), whether from transmission ownership or contractual entitlements, of each Participating TO_n for each ISO Scheduling Point which has been placed within the ISO Controlled Grid. Available Transfer Capacity shall not include capacity associated with Existing Rights of a Participating TO as defined in Section 2.4.4 of the ISO Tariff.
n	=	the number of Participating TOs from 1 to n

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ANCILLARY SERVICES REQUIREMENTS PROTOCOL

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ANCILLARY SERVICES REQUIREMENTS PROTOCOL (ASRP)

ASRP 1 OBJECTIVES, DEFINITIONS AND SCOPE

ASRP 1.1 Objectives

(a) The ISO needs to have available to it sufficient Ancillary Services of a standard necessary to enable it to maintain the reliability of the ISO Controlled Grid.

(b) This Protocol describes the ISO's basis for determining its Ancillary Services requirements and the required standard for each Ancillary Service.

(c) These requirements and standards apply to all Ancillary Services whether self-provided or procured by the ISO.

(d) This Protocol also describes the means by which the ISO will monitor performance of these Ancillary Services to ensure that the required standards are met and maintained.

ASRP 1.2 Definitions

ASRP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is to a Section or an Appendix of the ISO Tariff. References to ASRP are to this Protocol or to the stated paragraph of or Appendix to this Protocol.

ASRP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following expression shall have the meaning set opposite it:

"Area Control Error (ACE)" means the sum of the instantaneous difference between the actual net interchange and the scheduled net interchange between the ISO Control Area and all adjacent Control Areas and the ISO Control Area's frequency correction and time error correction obligations.

"Dynamic Schedule" means a telemetered reading or value which is updated in real time and which is used as a schedule in the ISO EMS calculation of ACE and the integrated value of which is treated as a schedule for interchange accounting purposes.

ASRP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of

the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

ASRP 1.3 Scope

ASRP 1.3.1 Scope of Application to Parties

This Protocol applies to the ISO and to the following:

(a) Participating Generators

(b) Operators

(c) UDCs

(d) Providers of Curtailable Demand

(e) Scheduling Coordinators

(f) Metered Subsystem Operators.

ASRP 1.3.2 Liability of the ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

ASRP 2 ANCILLARY SERVICES STANDARDS

ASRP 2.1 Basis of Standards

ASRP 2.1.1 Basic criteria

(a) The ISO shall base its Ancillary Services standards upon the Western Electricity Coordinating Council (WECC) Minimum Operating Reliability Criteria (MORC) and North American Electric Reliability Council (NERC) Criteria to the extent they are applicable to the ISO Controlled Grid.

(b) The ISO may adjust the Ancillary Services standards temporarily to take into account, among other things, variations in system conditions, real-time Dispatch constraints, contingencies, and voltage and dynamic stability assessments.

ASRP 2.2 **Review of Standards**

ASRP 2.2.1 **Grid Operations Committee Review**

The ISO Grid Operations Committee shall periodically undertake a review of the ISO Controlled Grid operations to determine any revision to the Ancillary Services standards to be used in the ISO Control Area. As a minimum the ISO Technical Advisory Committee shall conduct such reviews to accommodate revisions to WECC and NERC standards.

ASRP 2.2.2 **Contents of Grid Operations Committee Reviews**

Periodic reviews may include, but are not limited to:

(a) analysis of the deviation between actual and forecast Demand;

(b) analysis of patterns of unplanned Generating Unit Outages;

(c) analysis of compliance with NERC and WECC Criteria;

(d) analysis of operation during system disturbances;

(e) analysis of patterns of shortfalls between Final Day-Ahead Schedules and actual Generation and Demand; and

(f) analysis of patterns of unplanned transmission Outages.

ASRP 2.3 **Communications**

A Participating Generator or provider of Curtailable Demand wishing to offer any Ancillary Service must provide a direct ring down voice communications circuit (or a dedicated telephone line available 24 hours a day every day of the year) between the control room operator for the Generating Unit or Curtailable Demand providing the Ancillary Service and the ISO Control Center. Each Participating Generator must also provide an alternate method of voice communications with the ISO from the control room in addition to the direct communication link required above.

ASRP 3 **ANCILLARY SERVICE OBLIGATIONS FOR SCHEDULING COORDINATORS**

ASRP 3.1 **Ancillary Service Obligations**

The ISO shall assign to each Scheduling Coordinator a share of the ISO's total Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve requirements. The ISO will calculate the share for which each Scheduling Coordinator is responsible (its "obligation") in accordance with the standards set forth in the ASRP.

ASRP 3.2 **Right to Self-Provide**

Each Scheduling Coordinator may self-provide all, or a portion, of its Regulation and Reserve obligation within each Zone or adjust its obligation through Inter-Scheduling Coordinator Ancillary Service Trades

ASRP 4 **REGULATION STANDARDS**

ASRP 4.1 **Standard for Regulation: Quantity Needed**

ASRP 4.1.1 **Basis for Standard**

The ISO needs sufficient Generating Units immediately responsive to Automatic Generation Control (AGC) in order to allow the ISO Control Area to meet the WECC and NERC control performance criteria by continuously balancing Generation to meet deviations between actual and scheduled Demand and to maintain interchange schedules.

ASRP 4.1.2 **Determination of Regulation Quantity Needed**

The quantity of Regulation capacity needed for each Settlement Period of the Day-Ahead Market and the Hour-Ahead Markets shall be determined as a percentage of the aggregate scheduled Demand for that Settlement Period.

ASRP 4.1.3 **Percentage Determination**

The exact percentage required for each Settlement Period of the Day-Ahead Market and the Hour-Ahead Markets shall be determined by the ISO based upon its need to meet the WECC and NERC control performance criteria.

ASRP 4.1.4 **Publication of Estimated Percentage for Day-Ahead Market**

In accordance with the requirements of SP 3.2.1, the ISO will publish on WEnet its estimate of the percentage it will use for determining the quantity of Regulation it requires for each Settlement Period of the Day-Ahead Market for that Trading Day.

ASRP 4.1.5 **Publication of Estimated Percentage for Hour-Ahead Market**

The ISO will publish on WEnet its estimate of the percentage it will use to determine the quantity of Regulation it requires for each Hour-Ahead Market.

ASRP 4.1.6 **Additional Regulation Requirement**

Additional Regulation capacity may be procured by the ISO for the real-time operating period if needed to meet the WECC and NERC control performance criteria.

ASRP 4.2 **Standard for Regulation: Performance**

ASRP 4.2.1 **Operating Characteristics of Generating Unit**

A Generating Unit offering Regulation must have the following operating characteristics and technical capabilities:

(a) it must be capable of being controlled and monitored by the ISO Energy Management System (EMS) by means of the installation and use of a standard ISO direct communication and direct control system, a description of which and criteria for any temporary exemption from which, the ISO shall publish on the ISO internet "Home Page;"

function in accordance with the ISO's standards and procedures posted on the ISO Home Page.

ASRP 4.5 **Standard for Regulation: Procurement**

ASRP 4.5.1 **Procurement of Non Self-Provided Regulation**

Regulation necessary to meet ISO requirements not met by self-provided Regulation will be procured by the ISO as described in the ISO Tariff.

ASRP 4.5.2 **Certification and Testing Requirements**

Each Generating Unit and System Unit used to bid Regulation or used to self-provide Regulation must have been certified and tested by the ISO using the process defined in Appendix A to this Protocol.

ASRP 4.5.3 **[Not Used]**

ASRP 4.5.4 **[Not Used]**

ASRP 5 **OPERATING RESERVE STANDARDS**

The ISO needs, as a minimum, Operating Reserve, consisting of Spinning Reserve and Non-Spinning Reserve, sufficient to meet WECC MORC. The Operating Reserve requirement shall be equal to (a) 5% of the Demand (except the Demand covered by firm purchases from outside the ISO Control Area) to be met by Generation from hydroelectric resources, plus 7% of the Demand (except the Demand covered by firm purchases from outside the ISO Control Area) to be met by Generation from other resources, or (b) the single largest Contingency, if this is greater or (c) by reference to such more stringent criteria as the ISO may determine from time to time. This Operating Reserve requirement does not include the Operating Reserve required to cover the Generation or services described in ASRP 5.2(a) and (b).

ASRP 5.1 **Standard for Spinning Reserve: Quantity Needed**

ASRP 5.1.1 **Minimum Spinning Reserve Quantity**

The Spinning Reserve component of Operating Reserve shall be no less than one-half the Operating Reserve required for each Settlement Period of the Day-Ahead Market, the Hour-Ahead Market and the Real Time Market.

ASRP 5.1.2 **Providing both Spinning Reserve and Regulation**

Spinning Reserve and Regulation may be provided as separate services from the same Generating Unit, provided that the sum of Spinning Reserve and Regulation provided is not greater than the maximum ramp rate of the Generating Unit (MW/minute) times ten.

ASRP 5.2 **Standard for Non-Spinning Reserve: Quantity Needed**

The required quantity of Non-Spinning Reserve shall be equal to the required quantity of Operating Reserve less the quantity of Spinning Reserve determined in ASRP 5.1 plus;

(a) an amount of Non-Spinning Reserve equal to Interruptible Imports (which must either be self-provided by the Scheduling Coordinators responsible for the Interruptible Imports from resources within the ISO Controlled Grid or purchased from the ISO); and

(b) an amount of Non-Spinning Reserve equal to on-demand obligations to other entities or Control Areas (which must be self-provided by the Scheduling Coordinators responsible for the on-demand obligations from resources within the ISO Controlled Grid).

Scheduling Coordinators may self-provide their allocated quantity of Non-Spinning Reserve under ASRP 5.2(a) and (b) from Spinning Reserve not already committed to the ISO, if they wish.

ASRP 5.3 **Standard for Spinning Reserve: Performance**

ASRP 5.3.1 **Spinning Reserve Capability**

Each Generating Unit or external import of a System Resource scheduled to provide Spinning Reserve must be capable of converting the full capacity reserved to Energy production within ten minutes after the issue of the Dispatch instruction by the ISO, and of maintaining that output or scheduled interchange for at least two hours.

ASRP 5.3.2 **Availability**

Each Participating Generator shall ensure:

(a) that its Generating Units scheduled to provide Spinning Reserve are available for Dispatch throughout the Settlement Period for which it has been scheduled; and

(b) that its Generating Units scheduled to provide Spinning Reserve are responsive to frequency deviations throughout the Settlement Period for which they have been scheduled.

ASRP 5.4 **Standard for Non-Spinning Reserve Performance**

ASRP 5.4.1 **Non-Spinning Reserve Resources**

Non-Spinning Reserve may be provided by, among others, the following resources:

(a) Demand which can be reduced by Dispatch;

(b) interruptible exports;

(c) on-demand rights from other entities or Control Areas;

(d) off line Generating Units qualified to provide Non-Spinning Reserve; and

ASRP 5.8 **Standard for Operating Reserve: Procurement**

ASRP 5.8.1 **Procurement of Non Self-Provided Operating Reserve**

Operating Reserve necessary to meet ISO requirements not met by self-provided Operating Reserve will be procured by the ISO as described in the ISO Tariff.

ASRP 5.8.2 **Procurement Not Limited to ISO Control Area**

The ISO will procure Spinning and Non-Spinning Reserves from Generating Units operating within the ISO Control Area and external imports of System Resources.

ASRP 5.8.3 **Spinning Reserve Certification and Testing Requirements**

Spinning Reserve may only be provided from

(1) Generating Units;

(2) System Resources from external imports; or

(3) System Units;

which have been certified and tested by the ISO using the process defined in Appendix B to this Protocol.

ASRP 5.8.4 **Non-Spinning Reserve Certification and Testing Requirements**

Non-Spinning Reserve may only be provided from resources including

(1) Loads;

(2) Generating Units;

(3) System Resources from external imports; and

(4) System Units;

which have been certified and tested by the ISO using the process defined in Appendix C to this Protocol.

ASRP 5.8.5 **Self-Provision of Operating Reserve**

Scheduling Coordinators may self-provide Spinning and Non-Spinning Reserves from resources outside the ISO Control Area.

ASRP 6 **REPLACEMENT RESERVE STANDARDS**

ASRP 6.1 **Standard for Replacement Reserve: Quantity Needed**

ASRP 6.1.1 **Basis for Standard**

The ISO needs sufficient Replacement Reserve to be available to allow restoration of Dispatched Operating Reserve within sixty minutes to its Set Point scheduled for the Settlement Period concerned.

ASRP 6.1.2 **Replacement Reserve Requirements**

The ISO shall have discretion to determine the quantity of Replacement Reserve it requires in each Zone. The ISO shall

make its determination of the required quantity of Replacement Reserve based on:

(a) analysis of the deviation between aggregate forecast Demands supplied by Scheduling Coordinators and that forecast by ISO;

(b) analysis of patterns of unplanned Generating Unit Outages;

(c) analysis of patterns of shortfalls between Final Day-Ahead Schedules and actual Generation and Demand;

(d) analysis of patterns of unexpected transmission Outages;

(e) analysis of seasonal variations that may require additional Replacement Reserves; and

(f) other factors influencing the ISO Controlled Grid's ability to meet Applicable Reliability Criteria.

ASRP 6.2 **Standard for Replacement Reserve: Performance**

ASRP 6.2.1 **Replacement Reserve Supply Capability**

Each resource providing Replacement Reserve must be capable of supplying any level of output up to and including its full reserved capacity within sixty minutes after issue of Dispatch instructions by the ISO.

ASRP 6.2.2 **Replacement Reserve Availability**

Each resource providing Replacement Reserve must be capable of sustaining the instructed output for at least two hours.

ASRP 6.2.3 **Resources already Providing Ancillary Service**

Replacement Reserve may be supplied from resources already providing another Ancillary Service, such as Spinning Reserve, but only to the extent that the ability to provide the other Ancillary Service is not restricted in any way by the provision of Replacement Reserve. The sum of Ancillary Service capacity supplied by the same resource cannot exceed the capacity of said resource.

ASRP 6.3 **Scheduling Coordinator's Obligation for Replacement Reserve**

Scheduling Coordinator's Obligation for Replacement Reserve for each Settlement Period of the Day-Ahead Market and for each Hour-Ahead Market in each Zone shall be based upon the ratio of the metered Demand (excluding exports) by each Scheduling Coordinator in each identified Zone for that Settlement Period to the total metered Demand (excluding exports) for that Settlement Period in that Zone.

ASRP 6.4 **Standard for Replacement Reserve: Control**

Each provider of Replacement Reserve must be capable of receiving a Dispatch instruction within one minute from the time the ISO Control Center elects to Dispatch the Replacement Reserve resource and must ensure that its resource can be at the Dispatched operating level or condition within sixty minutes after issue of the Dispatch instruction.

ASRP 6.5 **Standard for Replacement Reserve: Procurement**

ASRP 6.5.1 **Procurement of Non Self-Provided Replacement Reserve**

Replacement Reserve necessary to meet ISO requirements not met by self-provided Replacement Reserve will be procured by the ISO as described in the ISO Tariff.

ASRP 6.5.2 **Procurement Not Limited to ISO Control Area**

The ISO will procure Replacement Reserves from Generating Units operating within the ISO Control Area and external imports of System Resources.

ASRP 6.5.3 **Self-Provision of Replacement Reserve**

Scheduling Coordinators may self-provide Replacement Reserves as external imports from System Resources located outside the ISO Control Area.

ASRP 6.5.4 **Certification and Testing Requirements**

Replacement Reserve may only be provided from resources including

(1) Loads;

(2) Generating Units;

(3) System Resources from external imports; and

(4) System Units

which have been certified and tested by the ISO using the process defined in Appendix C to this Protocol.

ASRP 7 **VOLTAGE SUPPORT STANDARDS**

ASRP 7.1 **Standard for Voltage Support: Quantity Needed**

The ISO shall determine on a daily basis for each Settlement Period for each Trading Day the quantity and location of Voltage Support required to maintain voltage levels and reactive margins within WECC and NERC criteria using a power flow study based on *the quantity and location of Demand scheduled in each Settlement* Period of the Day-Ahead Market. The ISO shall issue daily voltage schedules (Dispatch instructions) to Generators, Participating TOs and UDCs for each Trading Day, which are required to be *maintained for ISO Controlled Grid reliability.*

ASRP 7.2 **Standard for Voltage Support: Performance**

ASRP 7.2.1 **Automatic Voltage Regulation Requirement**

A Generating Unit providing Voltage Support must be under the control of generator automatic voltage regulators throughout the time period during which Voltage Support is required to be provided. A Generating Unit may be required to operate underexcited (absorb reactive power) at periods of light system Demand to avoid potential high voltage conditions, or overexcited

(produce reactive power) at periods of heavy system Demand to avoid potential low voltage conditions.

ASRP 7.2.2 **Compensation for Operating Outside of Range**

The ISO will not compensate Generators for operating their Generating Units within the power factor band of 0.90 lag to 0.95 lead. If the ISO requires additional Voltage Support in the short term it may instruct a reduction in a Generating Unit's MW output so that it operates outside its specified power factor range. The ISO will compensate Generators for this service as provided in the ISO Tariff.

ASRP 7.3 **Standard for Voltage Support: Distribution and Location**

Each Generator, Participating TO and UDC shall ensure that sufficient Voltage Support is available in the vicinity of each designated substation bus to maintain voltage within the Voltage Limits prescribed by the ISO in its voltage schedules for each Settlement Period. Each Generator, Participating TO and UDC shall provide sufficient reactive supply in each local area to take into account real power losses created by reactive power flow on the system. Reactive power flow at Scheduling Points shall be maintained within a power factor bandwidth of 0.97 lag to 0.99 lead.

ASRP 7.4 **Standard for Voltage Support: Control**

Generating Units providing Voltage Support must have automatic voltage regulators which can correct the bus voltages to be within the prescribed voltage limits and within the machine capability in less than one minute.

ASRP 7.5 **Standard for of Voltage Support: Procurement**

ASRP 7.5.1 **Long-Term Voltage Support**

As of the ISO Operations Date, the ISO will contract for long-term Voltage Support service with Owners of Reliability Must-Run Units under Reliability Must-Run Contracts.

ASRP 7.5.2 **Certification and Testing Requirements**

Voltage Support may only be provided from resources including Loads, Generating Units and System Units which have been certified and tested by the ISO using the process defined in Appendix E to this Protocol.

ASRP 8 **BLACK START STANDARDS**

ASRP 8.1 **Standard for Black Start: Quantity Needed**

ASRP 8.1.1 **Determination of Black Start Capability**

The ISO shall determine the amount and location of Black Start capability it requires by reference to contingency studies which will be used as the basis of the ISO's emergency plans.

instructions to start and synchronize the resource, testing of all communications circuits, simulating switching needed to connect the Black Start Generating Unit to the transmission system, and testing the features unique to each facility that relate to Black Start service.

ASRP 9.7 **Consequences of Failure to Pass Compliance Testing**

ASRP 9.7.1 **Notification of Compliance Testing Results**

If a Generating Unit, Load, or System Resource fails a compliance test, the ISO shall notify the Scheduling Coordinator whose resource was the subject of the test and the Ancillary Service Provider or owner or operator of a System Resource providing Ancillary Services of such failure by any means as soon as reasonably practicable after the completion of the test. In addition, regardless of the outcome of the test, the ISO shall provide the Scheduling Coordinator whose resource was subject to a compliance test written notice of the results of such test. The ISO shall at the same time send a copy of the notice to the Ancillary Service Provider or owner or operator of a System Resource providing Ancillary Services.

ASRP 9.7.2 **Penalties for Failure to Pass Compliance Testing**

The Scheduling Coordinator whose resource fails a compliance test shall be subject to the financial penalties provided for in the ISO Tariff. In addition, the ISO shall institute the sanctions described in ASRP 11.

ASRP 10 **PERFORMANCE AUDITS FOR STANDARD COMPLIANCE**

In addition to testing under ASRP 9, the ISO will periodically audit the performance of resources providing Ancillary Services to confirm the ability of such resources to meet the applicable Ancillary Service standard for performance and control.

ASRP 10.1 ***Performance Audit for Regulation***

The ISO will audit the performance of a Generating Unit providing Regulation by monitoring its response to ISO EMS control or, in the case of an external import of a System Resource providing Regulation, by monitoring the dynamic interchange response to ISO EMS control around its Set Point within its rated MW/minute capability over the range of Regulation capacity scheduled for the current Settlement Period.

ASRP 10.2 **Performance Audit for Spinning Reserve**

The ISO will audit the performance of a Generating Unit or external import of a System Resource providing Spinning Reserve by auditing its response to Dispatch instructions and by analysis of Meter Data associated with the Generating Unit. Such audits may not necessarily occur on the hour. A Generating Unit providing Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move at the MW/minute capability stated in its bid, reach the amount of Spinning Reserve capacity scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO, and respond to system frequency deviations outside the allowed frequency deadband. An external import of a System Resource providing Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move at the MW/minute capability stated in its bid, reach the amount of Spinning Reserve capacity scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO.

ASRP 10.3 **Performance Audit for Non-Spinning Reserve**

The ISO will audit the performance of a Generating Unit, Load, or System Resource providing Non-Spinning Reserve by auditing its response to Dispatch instructions, and by analysis of Meter Data associated with the resource. Such audits may not necessarily occur on the hour. A Generating Unit providing Non-Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move in accordance with the time delay and MW/minute capability stated in its bid, and reach the amount of Non-Spinning Reserve capacity under the control of the ISO scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO. An external import of a System Resource providing Non-Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move in accordance with the time delay and MW/minute capability stated in its bid, and reach the amount of Non-Spinning Reserve capacity scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO. A Load providing Non-Spinning Reserve from Curtailable Demand shall be evaluated on its ability to respond to a Dispatch instruction, move in accordance with the time delay and MW/minute capability stated in its bid, and reach the amount of Non-Spinning Reserve capacity scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO.

ASRP 10.4 **Performance Audit for Replacement Reserve**

The ISO will audit the performance of a Generating Unit, Load, or System Resource providing Replacement Reserve by auditing its response to Dispatch instructions, and by analysis of Meter Data associated with the resource. Such audits may not necessarily occur on the hour. A Generating Unit providing Replacement Reserve shall be evaluated on its ability to respond to a Dispatch instruction, start within the designated time delay, move at the MW/minute capability stated in its bid, reach the amount of Replacement Reserve capacity scheduled for the Settlement Period concerned within sixty minutes of issue of the Dispatch instruction, and sustain operation at this level for a sufficient time to assure availability over the specified period. An external import of a System Resource providing Replacement Reserve shall be evaluated on its ability to respond to a Dispatch instruction, start within the designated time delay, move at the MW/minute capability stated in its bid, reach the amount of Replacement Reserve capacity scheduled for the Settlement Period concerned within sixty minutes of issue of the Dispatch instruction, and sustain operation at this level for a sufficient time to assure availability over the specified period. A Load providing Replacement Reserve from Curtailable Demand shall be evaluated on its ability to respond to a Dispatch instruction, start within the designated time delay, move at the MW/minute capability stated in its bid, reach the amount of Replacement Reserve capacity scheduled for the Settlement Period concerned within sixty minutes of issue of the Dispatch instruction, and sustain operation at this level for a sufficient time to assure availability over the specified period.

ASRP 10.5 **Performance Audit for Voltage Support**

The ISO will audit the performance of a resource providing Voltage Support by auditing of its response to Dispatch instructions, and by analysis of Meter Data associated with the resource. A resource providing Voltage Support shall be evaluated on its ability to provide reactive support over the stated power factor range of the resource, provide reactive support within the prescribed time periods, and demonstrate the effective function of automatic voltage control equipment for

performance audit which gave rise to the issue of the warning notice, whichever is the earlier.

ASRP 11.4 **Second failure**

An Ancillary Service resource which fails a compliance test or a performance audit conducted during the period when a warning notice for that resource is in effect shall be disqualified immediately from providing the Ancillary Service concerned whether as part of the ISO's auction or as part of a self-provision arrangement, and shall not be permitted to submit a bid to the ISO or be part of a self-provision arrangement until such time as it has successfully re-passed the approval and certification procedure described in the relevant Appendix to this ASRP.

ASRP 12 **AMENDMENTS TO THE PROTOCOL**

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

DEMAND FORECASTING PROTOCOL (DFP)

DFP 1 Objectives, Definitions and Scope

DFP 1.1 Objectives

The objective of the DFP is to set forth procedures for submission of Demand Forecasts which will provide information to the ISO for projecting future Demand requirements to be served by the ISO Controlled Grid. The ISO shall utilize such forecasts to enable it to assess System Reliability and carry out its functions under the Scheduling Protocol (SP) and the Outage Coordination Protocol (OCP).

DFP 1.2 Definitions

DFP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix refers to a Section or an Appendix of the ISO Tariff unless otherwise indicated. References to DFP are to this Protocol or to the stated paragraph of this Protocol.

DFP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meaning set opposite them:

"Annual Peak Demand Forecast" means a Demand Forecast of the highest Hourly Demand in any hour in a calendar year, in MW.

"Congestion Zone" means a Zone identified as an Active Zone in Appendix I of the ISO Tariff.

"Hourly Demand" means the average of the instantaneous Demand integrated over a single clock hour, in MW.

"Weekly Peak Demand Forecast" means a Demand Forecast of the highest Hourly Demand in any hour in a period beginning at the start of the hour ending 0100 on Sunday and ending at the end of the hour ending 2400 the following Saturday, in MW.

DFP 2.3 Timing of Submission of Demand Forecasts

The Demand Forecasts described in DFP 2.1 shall be submitted by SCs to the ISO on a monthly basis by noon of the 18th working day of the month.

DFP 2.4 Forecast Standards

DFP 2.4.1 Avoiding Duplication

SCs submitting Demand Forecasts to the ISO shall ensure, to the best of their ability, that any Demand they are forecasting is not included in another SC's Demand Forecasts. To accomplish this, each SC's Demand Forecasts should only reflect those End-Use Customers who they actually have under contract and who have notified their UDC or previous SC of their intention to change to another SC, and which are actually scheduled to convert.

DFP 2.4.2 Required Performance

SCs submitting its Demand Forecasts to the ISO shall take all necessary actions to provide Demand Forecasts that reflect the best judgment of the submitting SC to help avoid potential System Reliability concerns and to enable the ISO to administer a meaningful market for Energy and Ancillary Services. From time to time the ISO may publish information on the accuracy of SC Demand Forecasts.

DFP 2.4.3 Incomplete or Unsuitable Demand Forecasts

If the Demand Forecasts supplied by a SC to the ISO are, in the ISO's opinion, incomplete or otherwise unsuitable for use, or a particular Demand Forecast has not been supplied by a SC to the ISO as required under this Protocol, the ISO will substitute the last valid Demand Forecast received from the SC in replacement for any incomplete, unsuitable or not supplied Demand Forecasts.

DFP 3 UDC Responsibilities

DFP 3.1 Data to be Submitted to the ISO by UDCs

At the time specified in DFP 3.3, each UDC shall submit to the ISO its Weekly Peak Demand Forecasts by Congestion Zone reflecting the Weekly Peak Demand Forecast for Load expected to be served by facilities under the control of the UDC. All Weekly Peak Demand Forecasts submitted shall include Demand Forecasts for the following 52 weeks.

DFP 3.2 Format of Demand Forecasts

Demand Forecasts must be submitted to the ISO electronically in the format set forth in Schedule 2 of this Protocol.

DISPATCH PROTOCOL

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DISPATCH PROTOCOL (DP)

DP 1 OBJECTIVES, DEFINITIONS AND SCOPE

DP 1.1 *Objectives*

The objectives of this Protocol are:

(a) to implement those sections of the ISO Tariff which involve real-time and emergency operations;

(b) to describe the real-time Dispatch of the Ancillary Services specified in the Ancillary Services Requirements Protocol (ASRP);

(c) to describe the operational activities of the ISO after all commitments have been made in the Hour-Ahead Market as described in the Scheduling Protocol (SP);

(d) to describe the use of Supplemental Energy bids received by the ISO in accordance with the Schedules and Bids Protocol (SBP); and

(e) to describe how the ISO will meet the operational requirements of NERC and WECC guidelines.

DP 1.2 Definitions

DP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is a reference to a Section or an Appendix of the ISO Tariff. References to DP are to this Protocol or to the stated paragraph of this Protocol.

DP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meanings set opposite them:

"Backup ISO Control Center" means the ISO Control Center located in Alhambra, California.

"Control Area Operator" means the person responsible for managing the real-time operations of a Control Area.

"Dispatch Instruction" means an operating order that is issued by the ISO to a Participant pertaining to real-time operations.

"GCC" means the single point of contact at the grid control center of Southern California Edison Company.

"Primary ISO Control Center" means the ISO Control Center located in Folsom, California.

"Participant" means any of those entities referred to in DP 1.3.1(a)-(f).

"Power System Stabilizer (PSS)" means an electronic control system applied on a Generating Unit that helps to damp out dynamic oscillations on a power system. The PSS senses Generator variables, such as voltage, current and shaft speed, processes this information and sends control signals to the Generator voltage regulator.

"Qualifying Facility" *means a qualifying co-generation or small power* production facility recognized by FERC.

"Reliability Coordinator" means the person responsible for Security Monitoring in real time for the California Area.

"TOC" means the single point of contact at the transmission operations center of Pacific Gas & Electric Company.

"Total Transfer Capability (TTC)" means the amount of power that can be transferred over an interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre-contingency and post-contingency system conditions.

"Western Interconnection" means a network of transmission lines embodied within the WECC Region.

DP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

(e) Time references in this Protocol are references to prevailing Pacific time.

DP 1.3 Scope

DP 1.3.1 Scope of Application to Parties

This Protocol applies to the ISO and to the Participants:

(a) Scheduling Coordinators (SCs);

(b) Utility Distribution Companies (UDCs);

(c) Participating Transmission Owners (PTOs);

(d) Participating Generators;

(e) Control Area Operators, to the extent the agreement between the Control Area Operator and the ISO so provides; and

(f) Metered Subsystem (MSS) Operators.

DP 1.3.2 Liability of the ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

DP 2 STANDARDS TO BE OBSERVED

DP 2.1 Applicable Reliability Criteria

The ISO shall exercise Operational Control over the ISO Controlled Grid in compliance with all Applicable Reliability Criteria. Applicable Reliability Criteria are defined as the standards established by NERC, WECC and Local Reliability Criteria and include the requirements of the Nuclear Regulatory Commission (NRC).

DP 2.1.1 WECC Criteria (Standards)

(a) Western Interconnection

The WECC set of standards for the Western Interconnection, which are based on the NERC standards. The WECC further

defines procedures and policies applicable to the Western Interconnection. WECC guidelines include:

(i) Part 1 – Reliability Criteria for Transmission System Planning

(ii) Part 2 – Power Supply Design Criteria

(iii) Part 3 – Minimum Operating Reliability Criteria (MORC)

(iv) Part 4 – Definitions

(b) Operating Procedures

The WECC Operating Procedures submitted to WECC by individual utilities and the ISO to address specific operating problems in their respective grids that could affect operations of the interconnected grid.

(c) Dispatcher's Handbook

The WECC Dispatcher's Handbook supplied by WECC to all utilities and Control Areas as a reference for dispatchers to use during normal and emergency operations of the grid.

DP 2.1.2 NERC Policies and Standards

(a) National Standards

The NERC national level standards for all utilities to follow to allow for safe and reliable operation of electric systems.

(b) Operating Manual

The NERC Operating Manual supplied by NERC to all utilities and Control Areas as a reference for dispatchers to use during normal and emergency operations of the grid.

DP 2.1.3 Local Reliability Criteria (Standards)

The reliability criteria unique to the transmission systems of each of the PTOs established at the later of: (1) the ISO Operations Date or (2) the date upon which a new Participating TO places its facilities under the control of the ISO. Each Participating TO must provide its Local Reliability Criteria to the ISO, as required by the TCA.

DP 2.1.4 NRC (Standards)

The reliability standards published by the NRC from time to time.

DP 2.2 Ancillary Services

The ISO will base its standards for the Dispatch of Ancillary Services upon WECC MORC and ISO Controlled Grid reliability requirements.

DP 2.3 ISO Standards

The ISO Governing Board may establish guidelines more stringent than those established by NERC and WECC as needed for the secure and reliable operation of the ISO Controlled Grid.

DP 2.4 Good Utility Practice (Standards)

When the ISO is exercising Operational Control of the ISO Controlled Grid, the ISO and Participants shall comply with Good Utility Practice. The ISO Tariff defines Good Utility Practice which, for ease of use of the DP, is repeated as follows:

> "Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be any one of a number of the optimum practices, methods, or acts to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region."

DP 2.5 Existing Contracts

The ISO will implement Sections 2.4.3 and 2.4.4 of the ISO Tariff with respect to Existing Contracts after the close of the Hour-Ahead Market and in real time.

DP 2.6 The Role of Participants

In issuing the Dispatch Instructions, the ISO will not intentionally request UDCs, Participating Generators, Generating Unit operators, or SCs to exceed any inherent plant rating or local restriction imposed by the plant or transmission owner in order to protect the design and/or operational integrity of its plant or equipment. In issuing Dispatch Instructions to PTOs, the ISO will comply with Section 5.1.7 of the TCA. Any conflict that may arise between an ISO issued Dispatch Instruction and a plant or transmission owner's restriction as mentioned above must be immediately brought to the ISO's attention by the person receiving such Dispatch Instruction prior to any attempt to implement that Dispatch Instruction.

DP 3 SCHEDULING AND REAL-TIME INFORMATION

DP 3.1 Final Schedules

The scheduling process described in the SP will produce for the ISO real-time dispatchers for each Settlement Period of the Trading Day a Final Schedule consisting of the combined commitments contained in the Final Day-Ahead Schedules and the Final Hour-Ahead Schedules for the relevant Settlement Period. The Final Schedule will include information with respect to:

(a) Generation schedules;

(b) Demand schedules;

(c) Ancillary Services schedules based on the ISO's Ancillary Services auction;

(d) Ancillary Services schedules, based on SCs' ISO accepted schedules and forecast load, for self-provided Ancillary Services;

(e) Interconnection schedules between the ISO Control Area and other Control Areas; and

(f) Inter-Scheduling Coordinator Energy Trades.

DP 3.2 Supplemental Energy

In addition to the Final Schedules, Supplemental Energy bids will be available to the ISO real-time dispatchers, as described in the SBP, by sixty (60) minutes prior to the start of the Settlement Period to which such Supplemental Energy bids apply.

DP 3.3 SC Intertie Schedules

In accordance with the SBP and the SP, SCs shall provide the ISO with Interconnection schedules prepared in accordance with all NERC, WECC and ISO requirements. The provisions of the SBP and the SP shall apply to real-time changes in Interconnection schedules under Existing Contracts.

DP 3.4 Information to be Supplied by SCs

DP 3.4.1 SC Dispatch

Each SC shall be responsible for the scheduling and Dispatch of Generation and Demand in accordance with its Final Schedule.

DP 3.4.2 Generator or Interconnection Schedule Change

Each SC shall keep the ISO appraised of any change or potential change in the current status of all Generating Units, Interconnection schedules and Inter-Scheduling Coordinator Energy Trades. This will

its SC any actual or potential concerns or problems that it may have with respect to Generating Unit direct digital control equipment, Generating Unit voltage control equipment, or any other equipment that may impact the reliable operation of the ISO Controlled Grid.

DP 3.7.2 Generator Schedules

In the event that a Generator cannot meet its Generation schedule, whether due to a Generating Unit trip or the loss of a piece of equipment causing a reduction in capacity or output, the Generator shall notify the ISO, through its SC at once. If a Generator will not be able to meet a time commitment or requires the cancellation of a Generating Unit start up, it shall notify the ISO, through its SC at once.

DP 3.8 Information to be Supplied by Control Area Operators

DP 3.8.1 System Status Change

The ISO and each adjacent Control Area Operator shall keep each other informed of any change or potential change in the status of the Interconnection and any changes in the Interconnection's TTC. The ISO and each adjacent Control Area Operator shall keep each other informed of situations such as adverse weather conditions, fires, etc., that could affect the reliability of any Interconnection. Each Control Area Operator of the Control Areas in the California area, as defined by the WECC Regional Security Plan, shall keep the ISO informed of all information required by WECC for use by the Reliability Coordinator.

DP 3.8.2 Scheduling Procedure

The ISO and each adjacent Control Area Operator shall follow all applicable NERC and WECC scheduling procedures. This will include checking the Interconnection schedules for the next Settlement Period prior to the start of the Energy ramp going into that hour. The ISO and each adjacent Control Area Operator shall check and agree on actual MWh net interchange after the hour for the previous Settlement Period. One Control Area shall change its actual number to reflect that of the other Control Area in accordance with WECC standard procedures.

DP 3.8.3 Data Exchange

The ISO and each adjacent Control Area Operator shall exchange MW, MVar, terminal and bus voltage data with each other on a four second update basis. MWh data for the previous hour shall be exchanged once per hour. All MW and MWh data for both the ISO Control Area and the adjacent Control Areas must originate from the same metering equipment.

DP 5.7.3 Notification of Restoration of Backup ISO Control Center

Once the Backup ISO Control Center is again available all functions will be transferred back, and the Backup ISO Control Center will notify all Participants via the WEnet.

DP 5.8 Use of IOUs' Energy Control Center Computers

The ISO and the IOUs will comply with the procedures for the utilization by the ISO of the IOUs' Energy control center computers when developed. The ISO will post such procedures on the WEnet when agreed.

DP 6 ROUTINE OPERATION OF THE ISO CONTROLLED GRID

DP 6.1 Overview/Responsibility

The ISO shall operate the ISO Controlled Grid in accordance with the standards described in DP 2 and within the limit of all applicable Nomograms and established operating limits and procedures.

DP 6.2 ISO Controlled Facilities

DP 6.2.1 General

The ISO shall have Operational Control of all transmission lines and associated station equipment that have been transferred to the ISO Controlled Grid from the PTOs as listed in the ISO Register.

DP 6.2.2 Primary ISO Control Center

The Primary ISO Control Center shall have Operational Control over:

(a) all transmission lines greater than 230kV and associated station equipment on the ISO Controlled Grid;

(b) all Interconnections; and

(c) all 230 kV and lower voltage transmission lines and associated station equipment identified in the ISO Register as that portion of the ISO Controlled Grid located in the PG&E Service Area.

DP 6.2.3 Backup ISO Control Center

The Backup ISO Control Center shall have Operational Control over all 230 kV and lower voltage transmission lines and associated station equipment identified in the ISO Register as that portion of the ISO Controlled Grid located in the SCE and SDGE Service Areas.

DP 6.3 Clearing Equipment for Work

The clearance procedures of the ISO and the relevant UDC and PTO must be adhered to by all parties, to ensure the safety of all personnel working on ISO Controlled Grid transmission lines and equipment. In accordance with the OCP, no work shall start on any equipment or line which is under the Operational Control of the ISO unless final approval has first been obtained from the appropriate ISO Control Center. Prior

to starting the switching to return any line or equipment to service the ISO shall confirm that all formal requests to work on the cleared line or equipment have been released.

DP 6.4 Equipment De-energized for Work

In some circumstances, System Reliability requirements may require a recall capability that can only be achieved by allowing work to proceed with the line or equipment de-energized only (i.e. not cleared and grounded). Any personnel working on such de-energized lines and equipment must take all precautions as if the line or equipment were energized. Prior to energizing any such lines or equipment deenergized for work, the ISO shall confirm that all formal requests to work on the de-energized line or equipment have been released.

DP 6.5 Hot-Line Work

The ISO has full authority to approve requests by PTOs to work on energized equipment under the Operational Control of the ISO, and no such work shall be commenced until the ISO has given its approval.

DP 6.6 Intertie Switching

The ISO and the appropriate single point of contact for the relevant PTO and the adjacent Control Area shall coordinate during the de-energizing or energizing of any Interconnection.

DP 6.7 Operating Voltage Control Equipment

DP 6.7.1 Operating Voltage Control Equipment Under ISO Control

The ISO will direct each PTO's single point of contact in the operation of voltage control equipment that is under the ISO's Operational Control.

DP 6.7.2 Operating Voltage Control Equipment Under UDC Control

Each UDC must operate voltage control equipment under UDC control in accordance with existing UDC voltage control guidelines.

DP 6.7.3 Special ISO Voltage Control Requirements

The ISO may request a PTO via its single point of contact or a UDC via its single point of contact to operate under special voltage control requirements from time to time due to special system conditions.

DP 6.8 Outages

The ISO will coordinate and approve Maintenance Outages and coordinate responses to Forced Outages of all transmission facilities in the ISO Controlled Grid and Reliability Must-Run Units in accordance with the OCP.

Any scheduled Outages that are cancelled by ISO real-time operations due to system requirements must be rescheduled with the ISO Outage Coordination Department in accordance with the OCP.

DP 6.9 Security Monitoring

The ISO shall be the Reliability Coordinator for the California Area. As Reliability Coordinator, the ISO, in conjunction with the other WECC Reliability Coordinators, will be responsible for the stable and reliable operation of the Western Interconnection in accordance with the WECC Regional Security Plan.

DP 6.9.1 Reliability Coordinator

As Reliability Coordinator, the ISO may direct activities as appropriate to curtail Schedules, Dispatch Generation or impose transfer limitations as necessary to relieve grid Congestion, mitigate potential overloads or eliminate operation outside of existing Nomogram criteria.

DP 6.9.2 Authority of WECC Reliability Coordinators

(a) The Reliability Coordinator has the final authority to direct operations before, during and after problems or disturbances that have regional impacts. The WECC Security Monitoring plans include collaboration with sub-regional Reliability Coordinators and Control Area operators to determine actions for anticipated problems. If there is insufficient time, or mutual concurrence is not reached, the Reliability Coordinator is authorized to direct actions and the control area operators must comply.

(b) In the event of any situation occurring which is outside those problems already identified in the list of known problems, the Reliability Coordinator shall have the responsibility and authority to implement whatever measures are necessary to maintain System Reliability. Those actions include but are not limited to; interchange curtailment, generation Dispatch adjustment (real power, reactive power and voltage), transmission configuration adjustments, special protection activation, load curtailment and any other action deemed necessary to maintain System Reliability.

(c) The Reliability Coordinator shall also have the responsibility and authority to take action in its sub-region for problems in another sub-region that it may help resolve. This must be accomplished at the request of and in coordination with the Reliability Coordinators of the other sub-regions.

DP 7 REAL-TIME OPERATIONAL ACTIVITIES – THE HOUR PRIOR TO THE SETTLEMENT PERIOD

DP 7.1 Schedule Confirmation

In the hour prior to the beginning of the Settlement Period, the ISO will review and evaluate the current system operating conditions to ensure sufficient Energy and Ancillary Services resources are available for the next Settlement Period. The ISO will:

DP 8 REAL-TIME OPERATIONAL ACTIVITIES – THE SETTLEMENT PERIOD

DP 8.1 Settlement Period

DP 8.1.1 Responsibility of the ISO in Real-Time Dispatch

During real-time Dispatch, the ISO, using RTD Software will be responsible for Dispatching Generating Units, Curtailable Demands and Interconnection schedules to meet real-time imbalances between actual and scheduled Demand and Generation and to relieve Congestion, if necessary, to ensure System Reliability and to maintain Applicable Reliability Criteria.

DP 8.1.2 [Not Used]

DP 8.2 Generating Units, Loads and Interconnection Schedules Dispatched for Congestion

The ISO will use the RTD Software to alleviate Inter-Zonal Congestion as described in DP 8.3. The ISO will manage Intra-Zonal Congestion in real time as set forth in Section 7.2.6.

DP 8.3 Inter-Zonal Congestion

DP 8.3.1 Treatment by Zone

If there is Inter-Zonal Congestion in real time, the ISO's RTD Software shall increase Generation and/or reduce Demand separately for each Zone to optimally Dispatch available resources to resolve the Congestion.

DP 8.3.2 Selection of Generating Unit or Load to Increase Generation or Reduce Demand

Where the ISO determines that it is necessary to increase Generation or reduce Demand in a Zone in order to relieve Inter-Zonal Congestion the ISO shall select in merit order, the Generating Unit within the Zone (or the Interconnection schedule in a Control Area adjacent to the Zone) with a non-zero capacity remaining to increment which has the lowest incremental bid price ($/MWh) or the Curtailable Demand located within the Zone (or the Interconnection schedule in a Control Area adjacent to the Zone) with a non-zero capacity remaining to reduce which has the lowest Demand reduction bid price.

DP 8.3.3 Selection of Generating Unit to Reduce Generation

Where the ISO determines that it is necessary to reduce Generation in a Zone in order to relieve Inter-Zonal Congestion, the ISO shall select in merit order the Generating Unit within the Zone with a non-zero capacity remaining to decrement which has the highest decremental bid price.

DP 8.4 Intra-Zonal Congestion

Except as provided in Section 5.2 of the ISO Tariff, in the event of Intra-Zonal Congestion, the ISO shall adjust Generating Units and Curtailable Demands (or Interconnection schedules of System Resources in the Control Areas) to alleviate the Constraints as described in Section 7.2.6.

DP 8.5 Additional Congestion Relief

In the event that there are insufficient resources which provide financial bids to mitigate Inter-Zonal and Intra-Zonal Congestion, Final Schedules which do not rely on Existing Contracts will be adjusted in real time by allocating transmission capacity on a pro rata basis. Final Schedules which rely on Existing Contracts will be adjusted in real time by allocating transmission capacity in accordance with the operating instructions submitted under SBP 3.3. With respect to facilities financed with Local Furnishing Bonds the ISO shall adjust Final Schedules in real time in a fashion consistent with Section 2.1.3 and 7.1.6.3 of the ISO Tariff, Appendix B of the TCA, and Operating Procedures governing the use of such facilities.

DP 8.6 Real-Time Dispatch Application

DP 8.6.1 Real-Time Dispatch

During real time, the ISO shall Dispatch Generating Units, Curtailable Demands and Interconnection schedules to meet imbalances between actual and scheduled Demand and Generation.

In addition, the ISO may need to purchase additional Ancillary Services if Ancillary Services arranged in advance are used to provide balancing Energy, and such depletion needs to be recovered to meet System Reliability contingency requirements.

DP 8.6.2 Utilization of the Energy Bids

The ISO will use the Energy Bids to Dispatch Supplemental Energy and Ancillary Services to procure balancing Energy for:

(a) satisfying needs for Imbalance Energy;

(b) mitigating Inter-Zonal Congestion;

(c) allowing resources providing Regulation service to return to the preferred operating point within their regulating ranges;

(d) allowing recovery of Operating Reserves utilized in real-time operations;

(e) procuring additional Voltage Support required from resources beyond their power factor ranges in real time; and

(f) Dispatching System Resources and Dispatchable Loads and increasing Generating Units' output to manage Intra-Zonal Congestion in real time using Energy Bids Dispatched out of sequence.

DP 8.6.3 Basis for Real-Time Dispatch

The ISO shall base real-time Dispatch of Generating Units, Curtailable Demands and Interconnection schedules on the following principles:

(a) the ISO shall Dispatch Generating Units and Dispatchable Interconnection schedules providing Regulation service to meet WECC and NERC Area Control Error (ACE) performance criteria;

(b) in each Dispatch Interval, following the loss of a resource and once ACE has returned to zero, the ISO shall determine if the Regulation Generating Units and Dispatchable Interconnection schedules are operating at a point away from their Set Point. The ISO shall then adjust the output of Generating Units, Curtailable Demands, and Dispatchable Interconnection schedules (either providing Spinning Reserve, Non-Spinning Reserve, Replacement Reserve, or Supplemental Energy) to return the Regulation Generating Units and Dispatchable Interconnection schedules to their Set Points to restore their full regulating margin;

(c) in each Dispatch Interval, the ISO shall Dispatch Generating Units, Curtailable Demands and Dispatchable Interconnection schedules to meet its balancing Energy requirements and eliminate any Price Overlap between Energy Bids, thereby, Dispatching the relevant resources in real time for economic trades either between SCs or within a SC's portfolio;

(d) the ISO shall select the Generating Units, Curtailable Demands and Dispatchable Interconnection schedules to be Dispatched to meet its balancing Energy requirements in merit order according to their Energy Bids;

(e) the ISO shall not discriminate between Generating Units, Curtailable Demands and Dispatchable Interconnection schedules other than based on price, and the effectiveness (location and ramp rate) of the resource concerned to respond to the fluctuation in Demand or Generation, or to resolve Inter-Zonal Congestion;

(f) Generating Units, Curtailable Demands or Dispatchable Interconnection schedules shall be Dispatched during the Settlement Period only until the next variation in Generation or Demand or the end of the Settlement Period, whichever is sooner. In Dispatching such resources, the ISO may make commitments beyond the current Settlement Period;

(g) The ISO will not differentiate between Ancillary Services procured by the ISO and Ancillary Services which are being self-provided;

(i) The operational ramp rate(s) of a resource will be considered by the RTD Software in determining the amount of Instructed Imbalance Energy by Dispatch Interval, and such consideration may result in Instructed Imbalance Energy in Dispatch Intervals prior to or subsequent to the Dispatch Interval to which the Dispatch Instruction applies;

(j) System Resources identified as Dispatchable within the operating hour pursuant to SBP Section 6.1.3 shall be Dispatched optimally through the RTD Software. Such bids will be settled pursuant to Section 11.2.4.1.1.2;

(k) The ISO will pre-dispatch Energy Bids from System Resources, subject to Hourly Pre-Dispatch as indicated in SBP 6.1.3, prior to the beginning of each hour consistent with applicable WECC interchange scheduling practices, assuring that any Price Overlap between such decremental and incremental Energy Bids will be eliminated. Such bids will be settled pursuant to Section 11.2.4.1.1.2.

DP 8.7 Ancillary Services Requirements

The following requirements apply to the Dispatch of Ancillary Services in real time:

DP 8.7.1 Regulation

(a) Regulation provided from Generating Units or System Resources must meet the standards specified in the ASRP;

(b) Non-Spinning Reserve:

(i) Non-Spinning Reserve provided from Generating Units, Demands, and external imports of System Resources must meet the standards specified in the ASRP;

(ii) the ISO may Dispatch Non-Spinning Reserve in place of Spinning Reserve to meet Applicable Reliability Criteria;

(iii) the ISO will Dispatch Non-Spinning Reserve in merit order of Energy bid prices as determined by the RTD Software; and

(iv) the ISO may Dispatch Non-Spinning Reserve to replace Spinning Reserve if there is a shortfall in Spinning Reserve because of a deficiency of balancing Energy;

DP 8.7.3 Replacement Reserve

(a) Replacement Reserve provided from Generating Units, Curtailable Demands and Interconnection schedules must meet the standards specified in the ASRP;

(b) the ISO will utilize Replacement Reserve to replace Operating Reserve that has been Dispatched due to a shortfall in Generation or an increase in Demand;

(c) the ISO may Dispatch Replacement Reserve to replace Operating Reserve that has been Dispatched for balancing Energy; and

(d) the ISO will Dispatch Replacement Reserve in merit order of Energy Bid prices as determined by RTD;

DP 8.7.4 Replacement of Operating Reserve

(a) in the event of an un-forecasted increase in system Demand or a shortfall in Generation output, the ISO shall utilize Replacement Reserve to restore Operating Reserve;

(b) if pre-arranged Operating Reserve is used to meet balancing Energy requirements, the ISO may replace such Operating Reserve by Dispatch of additional balancing Energy available from Supplemental Energy bids;

(c) any additional Operating Reserve needs may also be met the same way;

(d) where the ISO elects to rely upon Supplemental Energy bids, the ISO shall select the resources with the lowest incremental Energy Bid price as established by RTD; and

(e) if the ISO restores Operating Reserve through utilization of Replacement Reserve, the ISO is not required to replace the utilized Replacement Reserve;

DP 8.7.5 Voltage Support

(a) Voltage Support provided from Generating Units shall meet the standards specified in the ASRP;

(b) the ISO may Dispatch Generating Units to increase or decrease MVar output within the power factor limits of 0.9 lagging to 0.95 leading (or within other limits specified by the ISO in any exemption granted pursuant to Section 2.5.3.4 of the ISO Tariff) at no cost to the ISO when required for System Reliability;

(c) may Dispatch each Generating Unit to increase or decrease MVar output outside of established power factor limits, but within the range of the Generating Unit's capability curve, at a price calculated in accordance with ISO Tariff;

(d) If Voltage Support is required in addition to that provided pursuant to DP 8.7.5 (b) and (c), the ISO will reduce output of Participating Generators certified in accordance with the ASRP. The ISO will select Participating Generators in the vicinity where such additional Voltage Support is required; and

(e) the ISO will monitor voltage levels at Interconnections to maintain them in accordance with the applicable Inter-Control Area Agreements.

DP 8.7.6 Black Start

(a) Black Start shall meet the standards specified for Black Start in the ASRP; and

(b) the ISO will Dispatch Black Start as required in accordance with the applicable Black Start agreement.

DP 8.8 Real-Time Management of Overgeneration Conditions

In the event that Overgeneration conditions occur during real time, the ISO will direct the SCs to take the steps described in Section 2.3.4 of the ISO Tariff and SCs shall implement ISO directions without delay.

DP 9 DISPATCH INSTRUCTIONS

DP 9.1 ISO Dispatch Authority

DP 9.1.1 Range of ISO Authority

The ISO has full authority to:

(a) direct the physical operation of the ISO Controlled Grid, including (without limitation) circuit breakers, switches, voltage control equipment, protective relays, metering and Load Shedding equipment;

(b) commit Reliability Must-Run Generation, except that the ISO shall only commit Reliability Must-Run Generation for Ancillary Services capacity according to Section 5.2 of the Tariff;

(b) shall not be eligible to set the Dispatch Interval Ex Post Price.

DP 9.5.2 Sanctions

The ISO will develop additional mechanisms to deter Generating Units and Loads in the ISO or other Control Areas from failing to respond at a particular time or adequately respond over a particular period of time to a Dispatch Instruction or failing to perform according to Dispatch Instructions, for example, reduction in payments to SCs or suspension of the SC's Ancillary Services certificate for the Generating Unit, Curtailable Demand or System Resource concerned.

DP 10 EMERGENCY OPERATIONS

DP 10.1 Notifications by ISO

The ISO will provide the following notifications to Participants to communicate unusual system conditions or emergencies.

DP 10.1.1 System alert

ISO will give a system Alert Notice when the operating requirements of the ISO Controlled Grid are marginal because of Demand exceeding forecast, loss of major Generation or loss of transmission capacity that has curtailed imports into the ISO Control Area, or if the Hour-Ahead Market is short on scheduled Energy and Ancillary Services for the ISO Control Area.

DP 10.1.2 System warning

The ISO will give a system warning notice when the operating requirements for the ISO Controlled Grid are not being met in the Hour-Ahead Market, or the quantity of Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve and Supplemental Energy available to the ISO is not acceptable for the Applicable Reliability Criteria. This system warning notice will notify Participants that the ISO will, acting in accordance with Good Utility Practice, take such steps as it considers necessary to ensure compliance with Applicable Reliability Criteria, including the negotiation of Generation through processes other than competitive bids.

DP 10.1.3 System Emergency

When, in the judgement of the ISO, the System Reliability of the ISO Controlled Grid is in danger of instability, voltage collapse or under-frequency caused by transmission or Generation trouble in the ISO Control Area, or events outside of the ISO Control Area that could result in a cascade of events throughout the WECC grid, the ISO will declare a System Emergency. This declaration may include a notice to suspend the Day-Ahead, Hour-Ahead and Real Time Markets, authorize full use of Black Start Generation, initiate full control of manual Load Shedding, authorize the curtailment of Curtailable Demand (even though not scheduled as an Ancillary Service). The ISO will reduce the System Emergency declaration to a lower alert status when it is satisfied, after conferring with Reliability Coordinators within the WECC that the major contributing factors have been corrected, all

involuntarily interrupted Demand is back in service (except interrupted Curtailable Demand selected as an Ancillary Service). This reduction in alert status will reinstate the competitive markets if they have been suspended.

DP 10.2 Management of System Emergencies

DP 10.2.1 Declaration of System Emergencies

The ISO shall, when it determines that a System Emergency exists, declare the existence of such System Emergency. A declaration of System Emergency by the ISO shall be binding on all Participants until the ISO announces that the System Emergency no longer exists.

DP 10.2.2 Emergency Procedures

In the event of a System Emergency, the ISO shall:

(a) take action as it considers necessary to preserve or restore stable operation of the ISO Controlled Grid;

(b) act in accordance with Good Utility Practice to preserve or restore reliable, safe and efficient service as quickly as reasonably practicable;

(c) keep adjacent Control Area Operators informed as to the nature and extent of the System Emergency in accordance with WECC procedures; and

(d) where practicable, keep the Participants within the ISO Control Area informed.

DP 10.2.3 Intervention in Market Operations

(a) The ISO may intervene in the operation of the Day-Ahead, Hour-Ahead or Real Time Markets and set the Administrative Price if the ISO determines that such intervention is necessary in order to contain or correct the System Emergency.

(b) The ISO will not intervene in the operation of the Day-Ahead Market unless there has been a total or major collapse of the ISO Controlled Grid and the ISO is in the process of restoring it.

(c) Before any such intervention, the ISO must (in the following order):

(i) Dispatch all scheduled Generation and all other Generation offered or available to it, regardless of price (including all Supplemental Energy bids, and Ancillary Services);

(ii) Dispatch all interruptible Loads made available by UDCs to the ISO in accordance with the UDC Operating Agreements;

(c) instruct the alteration of scheduled deliveries of Energy and/or Ancillary Services into or out of the ISO Controlled Grid,

if such an instruction is reasonably necessary to prevent an imminent System Emergency or to retain Operational Control over the ISO Controlled Grid during an actual System Emergency, and provided that the ISO has, where reasonably practicable, utilized Ancillary Services which it has the contractual right to instruct and which are capable of contributing to or containing or correcting actual, imminent or threatened System Emergencies prior to issuing such instructions.

DP 10.3 External Support/Assistance

If, on a real-time basis, the ISO is unable to comply with the Applicable Reliability Criteria, the ISO shall take such steps as it considers necessary, to ensure compliance, including the negotiation of contracts for Ancillary Services through processes other than competitive solicitations. If the ISO is unable to obtain such resources from within the ISO Controlled Grid, the ISO may solicit Ancillary Services from other Control Areas on a real-time basis.

DP 10.4 UDC Emergency Procedures

In the event of a System Emergency, each UDC shall comply with all directions from the ISO concerning the management and alleviation of the System Emergency and shall comply with all procedures outlined in this Protocol.

DP 10.4.1 Use of UDC's Existing Load Curtailment Programs.

(a) UDC Electrical Emergency Plans

The ISO shall have the authority to implement a UDC's Electrical Emergency Plan in consultation with the UDC, when Energy reserve margins are forecast to be at the levels specified in the existing plan.

(b) UDC Under-Frequency Load Shedding Programs (UFLS):

The ISO shall:

(i) with the UDC, review that UDC's UFLS program periodically to ensure compliance with Applicable Reliability Criteria;

(ii) perform periodic audits of each UDC's UFLS to verify that the system is properly configured for each UDC; and

(iii) use reasonable endeavors to ensure that the total ISO UFLS is coordinated among the UDCs so that no UDC bears a disproportionate share of the total ISO UFLS program.

(c) UDC Disconnect Load

The ISO shall have the authority to direct a UDC to disconnect Load from the ISO Controlled Grid if necessary to avoid an anticipated System Emergency or to regain Operational Control over the ISO Controlled Grid during an actual System Emergency.

(d) UDC Load Curtailment Programs

As an additional resource for maintaining reliability and managing System Emergencies, the ISO may notify UDCs when the conditions exist which require the UDCs to implement their Load curtailment programs. The UDCs will exercise their best efforts, including seeking any necessary regulatory approvals, to enable the ISO to rely on their curtailment rights at specified levels of Operating Reserve.

DP 10.4.2 Load Curtailment

A SC may specify that Load will be reduced at specified Market Clearing Prices or offer the right to exercise Load curtailment to the ISO as an Ancillary Service or utilize Load curtailment itself (by way of self-provision of Ancillary Services) as Non-Spinning Reserve or Replacement Reserve. The ISO, at its discretion, may require direct control over such Curtailable Demand to assume response capability for managing System Emergencies. The ISO may establish standards for automatic communication of curtailment instructions to implement Load curtailment as a condition for accepting any offered Load curtailment as an Ancillary Service.

DP 11 ALGORITHMS TO BE USED

The ISO shall develop Dispatch algorithms for use by the ISO for Dispatching Generating Units and Curtailable Demands in accordance with the ISO Tariff.

DP 12 INFORMATION MANAGEMENT

The ISO shall provide all Participants with non-discriminatory access to information concerning the status of the ISO Controlled Grid by posting such information on the WEnet, or other similar computer communications device, or by telephone or facsimile in the event of computer systems failure.

DP 13 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

ISO MARKET MONITORING AND INFORMATION PROTOCOL

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MMIP 1.2.2 Special Terms for This Protocol

In this Protocol, the following words and expressions shall have the meanings set opposite them:

"Market Surveillance Unit" means the unit established under MMIP 3.1.

"ISO Market Surveillance Committee (ISO MSC)" means the committee established under MMIP 5.1.

"Activity Rules" means the rules relating to the activities of ISO Participants set forth in or referred to in the ISO Tariff and Protocols.

MMIP 1.2.3 Rules of Interpretation

MMIP 1.2.3.1 Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

MMIP 1.2.3.2 A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

MMIP 1.2.3.3 The captions and headings in this MMIP are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

MMIP 1.2.3.4 This Protocol shall be effective as of January 1, 1998.

MMIP 1.3 Scope

MMIP 1.3.1 Scope of Application to Parties

The MMIP applies to:

MMIP 1.3.1.1 All ISO Market Participants;

MMIP 1.3.1.2 The ISO.

MMIP 1.3.2 Liability of ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

MMIP 2 PRACTICES SUBJECT TO SCRUTINY

MMIP 2.1 Practices Subject to Scrutiny - General

The Market Surveillance Unit shall monitor the activities of Market Participants and other entities described in MMIP 1.3.1. It shall monitor

such activities that affect the operation of the ISO Markets and that provide indications of the phenomena set forth below in this Section 2.1 and, where appropriate, it will take such further action as it considers necessary under Section 2.3.

MMIP 2.1.1 **Anomalous Market Behavior**

Anomalous market behavior, which is defined as behavior that departs significantly from the normal behavior in competitive markets that do not require continuing regulation or as behavior leading to unusual or unexplained market outcomes. Evidence of such behavior may be derived from a number of circumstances, including:

MMIP 2.1.1.1 withholding of Generation capacity under circumstances in which it would normally be offered in a competitive market;

MMIP 2.1.1.2 unexplained or unusual redeclarations of availability by Generators;

MMIP 2.1.1.3 unusual trades or transactions;

MMIP 2.1.1.4 pricing and bidding patterns that are inconsistent with prevailing supply and demand conditions, *e.g.,* prices and bids that appear consistently excessive for or otherwise inconsistent with such conditions; and

MMIP 2.1.1.5 unusual activity or circumstances relating to imports from or exports to other markets or exchanges.

The Market Surveillance Unit shall evaluate, on an ongoing basis, whether the continued or persistent presence of such circumstances indicates the presence of behavior that is designed to or has the potential to distort the operation and efficient functioning of a competitive market, *e.g.,* the strategic withholding and redeclaring of capacity, and whether it indicates the presence and exercise of market power or of other unacceptable practices.

MMIP 2.1.2 **Abuse of Reliability Must-Run Unit Status**

Where Generating Units are determined by the ISO to be Reliability Must-Run Units, circumstances that indicate that such Generating Units are being operated in a manner that will adversely affect the competitive nature and efficient workings of the ISO Markets.

MMIP 2.1.3 **Gaming**

"Gaming", or taking unfair advantage of the rules and procedures set forth in the ISO Tariff, Protocols or Activity Rules, or of transmission Constraints in periods in which exist substantial Congestion, to the detriment of the efficiency of, and of consumers in, the ISO Markets. "Gaming" may also include taking undue advantage of other conditions that may affect the availability of transmission and generation capacity, such as Loop Flow, facility outages, level of hydropower output or seasonal limits on energy imports from out-of-state, or actions or behaviors that may otherwise render the system and the ISO Markets vulnerable to price manipulation to the detriment of their efficiency.

MMIP 2.1.4 ISO and Other Design Flaws

Design flaws and inefficiencies in the ISO Tariff, ISO Protocols and operational rules and procedures of the ISO, including the potential for problems between the ISO and other independent power exchanges, insofar as they affect the ISO Markets which may be evident from anomalous market behavior monitored under MMIP 2.1.1 above, from evidence of gaming monitored under MMIP 2.1.3 above, or from other activities.

MMIP 2.1.5 Market Structure Flaws

With respect to flaws in the overall structure of the California energy markets that may reveal undue concentrations of market power in Generation or other structural flaws, the Market Surveillance Unit shall provide such information or evidence of such flaws and such analysis as it may conduct to the ISO CEO, the ISO Market Surveillance Committee or to the ISO Governing Board, subject to due protections of confidential or commercially sensitive information. After due internal consultation, if instructed by any of such ISO institutions or persons, the Market Surveillance Unit shall also provide such information or evidence to the appropriate regulatory and antitrust enforcement agency or agencies, subject to due protections of confidential or commercially sensitive information. The Market Surveillance Unit shall, provide such other evidence, views, analyses or testimony as may be appropriate or required and as it is reasonably capable of providing to assist the investigations of such agencies.

MMIP 2.2 Practices Subject to Scrutiny Pending Divestiture

In the transition periods pending completion of the various divestiture plans undertaken by certain of the IOU's ("the pre-divestiture period"), the Market Surveillance Unit shall undertake the following measures to monitor the special circumstances that may affect the operation of the ISO Markets during this period and may recommend corrective actions as provided in Section 2.3.

MMIP 2.2.1 Exercises of Horizontal Market Power

The Market Surveillance Unit shall consider issues that have been raised that some ISO Participants may be able to exercise horizontal market power in the short term during this transition period.

MMIP 2.2.2 IOU Mitigation Plans

The Market Surveillance Unit shall review all IOU mitigation plans, as approved and modified by the FERC and other regulatory agencies, that might affect the competitiveness of and the efficient operation of the ISO Markets. The Market Surveillance Unit shall analyze what further actions may be necessary to ensure the effective implementation of these mitigation plans with respect to the ISO Markets, and may make such recommendations for further actions as it considers appropriate to the ISO CEO and Governing Board, the FERC, the CPUC or other regulatory agencies. The Market Surveillance Unit shall monitor the

ongoing implementation of such plans to the extent feasible within the area of its responsibility, capability and resources.

MMIP 2.2.3 Effects Pending Divestiture

In the pre-divestiture period, the Market Surveillance Unit shall monitor and analyze the combined effect of the operations of the CTC and the rate freeze under which the Companies are required to operate during the pre-divestiture period on the state of competition in and the efficient operation of the ISO Markets.

MMIP 2.3 Response Action by ISO

MMIP 2.3.1 Corrective Actions

Where the monitoring activities or any consequent investigations carried out by the Market Surveillance Unit pursuant to MMIP 2 and MMIP 4 reveal a significant possibility of the presence of or potential for exercises of market power that would adversely affect the operation of the ISO Markets, or the markets otherwise operating in the State of California, the Market Surveillance Unit shall take the appropriate measures under this section and under MMIP 4, 6, and 7 to institute the corrective action most effective and appropriate for the situation or, in the case of markets otherwise operating in the State of California, the Market Surveillance Unit may recommend corrective actions to the appropriate regulatory agencies.

MMIP 2.3.2 Further Actions

Where the monitoring activities of or any consequent investigations carried out by the Market Surveillance Unit pursuant to MMIP 2.1 and 2.2 reveal that activities or behavior of Market Participants in the ISO Markets have the effect of, or potential for, undermining the efficiency, workability or reliability of the ISO Markets to give or to serve such Market Participants an unfair competitive advantage over other Market Participants, the Market Surveillance Unit shall fully investigate and analyze the effect of such activities or behavior and, where appropriate, make recommendations to the ISO CEO and the ISO MSC for further action by the ISO or, where necessary, by other entities. The ISO may publicize such activities or behavior and its recommendations thereof, in whatever medium it believes most appropriate. The Market Surveillance Unit may, where appropriate, make specific recommendations for amendment to rules and protocols under its control, or for changes to the structure of the ISO Markets, and the Market Surveillance Unit may recommend actions, including fines or suspensions, against specific entities in order to deter such activities or behavior.

MMIP 2.3.3 Response to Gaming Behavior

If evidence of "gaming" or taking undue advantage exists, as described in MMIP 2.1.4, the Market Surveillance Unit shall review the "gaming" behavior and/or the relationship between system conditions and market behavior and pricing in order to assess the potential for and impact of such gaming behavior, with a view to taking appropriate action, if necessary, either with respect to structural changes such as Zone changes, or to changes to the ISO Tariff, Protocols or Activity Rules, or to proscribe specific behavior by Market Participants. In carrying out such activities the Market Surveillance Unit shall in appropriate circumstances seek the advice of the ISO MSC on the merits of such actions. In appropriate circumstances, the Market Surveillance Unit may institute or arrange for ADR procedures involving Market Participants with conflicting perspectives, e.g. as to whether a particular practice is better characterized as improper gaming or legitimate aggressive competition or as to whether rule changes may resolve conflicts.

MMIP 2.3.4 Adverse Effects of Transition Mechanisms

Should the monitoring and analysis conducted under MMIP 2.2.3 reveal significant adverse effects of transition mechanisms on competition in or the efficient operation of the ISO Markets, the Market Surveillance Unit shall examine and fully assess the efficacy of all possible measures that may be taken by the ISO, in order to prevent or to *mitigate such adverse effects. The Market Surveillance Unit shall make* such recommendations to the CEO of the ISO and to the ISO MSC as it considers appropriate for action in this regard by the ISO or for referral to the regulatory or antitrust enforcement agencies. Such proposed measures may include, but shall not be limited to the following:

MMIP 2.3.4.1 the use of direct bid caps as a mechanism to prevent or mitigate artificially high Market Clearing Prices caused by abuses of market power;

MMIP 2.3.4.2 the use of contracts for differences for eliminating the incentive for Generators to bid ISO prices to artificially high levels enabled by the presence of market power;

MMIP 2.3.4.3 calling upon Reliability Must-Run Units to operate; and to modify Reliability Must-Run Contracts;

MMIP 2.3.4.4 bid floors to prevent or mitigate the possible exercise of below-cost bidding or predatory pricing that may arise from the incentives provided by the combined effect of the CTC and the rate freeze when the IOUs are net buyers of Energy.

The CEO and the ISO MSC shall consult on such recommendations and each may, after due consideration, propose any of such measures to the ISO Governing Board. In the event that the ISO Governing Board adopts, and where necessary obtains regulatory approval for, any

MMIP 3.3.3.2 The ISO CEO shall ensure that the Market Surveillance Unit has adequate resources and full access to data and the full cooperation of all parts of the ISO organization in developing the database necessary for the effective functioning of the Market Surveillance Unit and the fulfillment of its monitoring function. The ISO CEO shall institute within the ISO such data collection, organization and analytic activities as may be necessary for the Market Surveillance Unit to fulfill its functions and responsibilities.

MMIP 3.3.4 Regulatory and Antitrust Enforcement Agencies

Where considered necessary and appropriate, or where so ordered by the regulatory or antitrust agency with jurisdiction over the matter in question, or by a court of competent jurisdiction, the Market Surveillance Unit shall refer a matter through the ISO CEO to the regulatory or antitrust enforcement agency concerned, *e.g.,* in cases of serious abuse requiring expeditious investigation or action by the agency. In all such cases of direct referral, the ISO CEO shall promptly inform the ISO Governing Board and the ISO MSC of the fact of and the content of the referral.

MMIP 3.3.5 Complaints

Any Market Participant, or any other interested entity, may at any time submit information to or make a complaint to the Market Surveillance Unit concerning any matter that it believes may be relevant to the Market Surveillance Unit's monitoring responsibilities. Such submissions or complaints may be made on a confidential basis in which case the Market Surveillance Unit shall preserve the confidentiality thereof. The Market Surveillance Unit, at its discretion, may request further information from such entity and carry out any investigation that it considers appropriate as to the concern raised. The Market Surveillance Unit shall periodically make reports to the ISO CEO and ISO Governing Board on complaints received.

MMIP 4 SPECIFIC FUNCTIONS OF ISO MARKET SURVEILLANCE UNIT

MMIP 4.1 Information Gathering and Market Monitoring Indices for Evaluation

MMIP 4.1.1 Information System

The Market Surveillance Unit shall be responsible for developing an information system and criteria for evaluation that will permit it to effectively monitor the ISO Markets to identify and investigate abuses of that market, whether caused by exercises of market power or by other actions or inactions.

MMIP 4.1.2 Data Categories

To develop the information system set forth in MMIP 4.1.1, the Market Surveillance Unit shall initially develop, and shall refine on the basis of experience, a detailed catalog of all the categories of data it will have the means of acquiring, and the procedures it will use (including procedures for protecting confidential data) to handle such data.

MMIP 4.1.3 Catalog of Market Monitoring Indices

The Market Surveillance Unit shall initially develop, and shall refine on the basis of experience, a catalog of the ISO Market monitoring indices that it will use to evaluate the data so collected.

MMIP 4.2 Evaluation of Information

MMIP 4.2.1 Ongoing Evaluation

The Market Surveillance Unit shall evaluate and reevaluate on an ongoing basis the data categories and market monitoring indices that it has developed under MMIP 4.1.2 and 4.1.3, and the information it collects and receives from various other sources, including and in particular the ISO's operation of the ISO Markets. Such ongoing evaluations shall provide the basis for its reporting and publication responsibilities as set forth in this Protocol, for recommendations on proposed changes to the ISO Tariff and ISO Protocols and other potential rules affecting the ISO Markets, and for the development of criteria or standards for the initiation of proposed corrective or enforcement actions. In evaluating such information, the Market Surveillance Unit may consult the ISO MSC or such external bodies as may be appropriate.

MMIP 4.2.2 Submission of Evaluation Results

The final results of the Market Surveillance Unit's evaluations shall routinely and promptly be submitted simultaneously to the ISO CEO and to the ISO MSC for comment.

MMIP 4.3 Review of Activity Rules

When an iterative bidding process is developed that requires the application of Activity Rules developed by the ISO, the Market Surveillance Unit shall review such Activity Rules for their effectiveness and consistency with its market monitoring activities and standards. The Market Surveillance Unit may at that time, and from time to time thereafter based on its experience in monitoring the ISO Markets, propose that changes be made in such Activity Rules.

MMIP 4.4 Reports and Recommendations

MMIP 4.4.1 ISO CEO and Governing Board

On the basis of the evaluation conducted under MMIP 4.2 or the review conducted under MMIP 4.3, the Market Surveillance Unit shall prepare periodic reports, as required by the ISO CEO, and specific ad hoc reports as appropriate, for the ISO CEO and ISO Governing Board on the state of competition in or the efficiency of the ISO Markets; and on its monitoring activities, the results of its evaluation and review activities, and its development and implementation of recommendations. Where appropriate, the ISO Market Surveillance Unit may recommend actions to be taken, including the amendment of the ISO Tariff and ISO Protocols and corrective or enforcement action against specific entities. Such reports shall be made not less frequently than quarterly in the case of the ISO CEO and ISO MSC and annually in

the case of the ISO Governing Board and shall contain such information and be in such form as specified by such entities. Such reports shall be made public and publicized as specified by such entities except to the extent that they contain confidential or commercially sensitive information or to the extent such entities determine that effective enforcement of the monitoring function dictates otherwise.

MMIP 4.4.2 Regulatory Agencies

As required in the ISO Tariff or by the ISO CEO and ISO Governing Board, or as required by the regulatory agency with jurisdiction over the matters in question, the Market Surveillance Unit shall prepare reports to the FERC and other regulatory agencies, which shall be reviewed and approved by the ISO CEO and Governing Board and then submitted as required. When publicly available reports are made to one regulatory agency with competent jurisdiction, such as the FERC, the Market Surveillance Unit may simultaneously make such reports available to other regulatory agencies with legitimate interests in their contents, such as the CPUC and CEC.

MMIP 4.4.3 ISO Market Surveillance Committee

All reports and recommendations to be made to the ISO CEO and ISO Governing Board under MMIP 4.4.1, or to regulatory agencies under MMIP 4.4.2, unless urgency requires otherwise, shall first be submitted to the ISO MSC for comments, which comments shall be reflected in the submittal to the ISO Governing Board. In addition, the Market Surveillance Unit may submit specific reports to the ISO MSC itself, as it considers appropriate. All final reports made to external regulatory agencies shall be simultaneously submitted to the ISO MSC.

MMIP 4.5 ISO Participants

MMIP 4.5.1 Collection of Data

The Market Surveillance Unit may request the submission of any information or data determined by the Market Surveillance Unit to be potentially relevant by ISO Participants or other entities whose activities may affect the operation of the ISO Market. This data will be subject to due safeguards to protect confidential and commercially sensitive data. Failures by ISO Participants to provide such data shall be treated under MMIP 4.5.2. In the event of failures by other entities to provide such data, the Market Surveillance Unit may report the failure to the ISO CEO and Governing Board or the pertinent regulatory agency, as appropriate, after providing such entity the opportunity to respond in writing as to the reason for the alleged failure.

MMIP 4.5.2 Provision of Data by ISO Participants

Failure by an ISO Participant to provide information requested pursuant to MMIP 4.5.1, or otherwise to cooperate in the Market Surveillance Unit's data collection or investigation activities, may be treated as grounds for action against the ISO Participant entity concerned. Such action may lead to the imposition of such penalties or sanctions as are permitted under the ISO Tariff or related protocols approved by FERC

and may include possible exclusion from the ISO Markets or termination of any relevant ISO agreements or certifications. Before any such action is taken, the ISO Participant shall be provided the opportunity to respond in writing as to the reason for the alleged failure.

MMIP 4.5.3 Dissemination of Data

ISO Participants may request that the ISO provide data that it has collected; and, upon approval of the ISO CEO and at his sole discretion, such data may, subject to constraints on the ISO's resources, be provided by the ISO subject to due safeguards to protect confidential and commercially sensitive data. Where such activity imposes a significant burden or expense on the ISO, the data may be provided on the condition that a reasonable contribution to the cost incurred by the ISO is made to the ISO by the requesting party.

MMIP 4.6 External Consulting Assistance and Expert Advice

In carrying out any of its responsibilities under this MMIP 4, including the development of an information system, market monitoring indices and evaluation criteria, and the catalogs associated therewith, and in its analysis and ongoing evaluation of these catalogs and of the Activity Rules under MMIP 4.3, the Market Surveillance Unit may hire consulting assistance subject to the budgetary approval of the ISO CEO and may seek such expert external advice as it believes necessary.

MMIP 4.7 **Liability for Damages**

As provided in Section 14.1 and 14.2 of the ISO Tariff, the Market Surveillance Unit, the ISO MSC, the ISO CEO and other ISO staff shall not be liable to any Market Participant under any circumstances whatsoever for any matter described in those sections, including but not limited to any financial loss or loss of economic advantage resulting from the performance or non-performance by such ISO entities of their functions under this Protocol.

MMIP 5 **ISO MARKET SURVEILLANCE COMMITTEE**

MMIP 5.1 **Establishment**

There shall be established on or before ISO Operations Date an ISO Market Surveillance Committee (ISO MSC), whose role it shall be to provide independent external expertise on the ISO market monitoring process as described in this Protocol and, in particular, to provide independent expert advice and recommendations to the ISO CEO and Governing Board. Members of the Committee are not employees or agents of the ISO. Members are not available to provide expert witness services to the ISO or any other party in a FERC proceeding relating to the ISO, except to the extent that the ISO MSC makes an advance determination that providing such service is not inconsistent with the independence of the ISO MSC.

MMIP 5.2 **Composition**

MMIP 5.2.1 **Qualifications**

The ISO MSC shall comprise a body of three or more independent and recognized experts whose combined professional expertise and experience shall encompass the following:

MMIP 5.2.1.1 economics, with emphasis on antitrust, competition, and market power issues in the electricity industry;

MMIP 5.2.1.2 experience in operational aspects of Generation and transmission in electricity markets;

MMIP 5.2.1.3 experience in antitrust or competition law in regulated industries; and

MMIP 5.2.1.4 financial expertise relevant to energy or other commodity trading.

MMIP 5.2.2 **Criteria for Independence**

Each member of the ISO MSC must meet the following criteria for independence in order to be appointed:

MMIP 5.2.2.1 no material affiliation, through employment, consulting or otherwise, with any Market Participant or Affiliate thereof consistent with the pertinent FERC Standards of Conduct; and

MMIP 5.2.2.2 no material financial interest in any Market Participant or Affiliate thereof consistent with the pertinent FERC Standards of Conduct.

MMIP 5.3 **Appointments to the ISO MSC**

For each position on the ISO MSC, the ISO CEO shall conduct a thorough search and requisite due diligence to develop a nomination to the ISO Governing Board, which nomination shall be consistent with meeting the combined professional expertise and experience of the ISO MSC set forth in MMIP 5.2.1 and with the criteria for independence set forth in MMIP 5.2.2. The ISO Governing Board shall expeditiously consider such nominations. If the nomination is approved, the ISO CEO shall appoint the candidate so nominated to the ISO MSC. If the nomination is rejected, the ISO CEO shall expeditiously proceed to develop another nomination in accordance with this MMIP.

MMIP 5.4 **Compensation and Reimbursements**

Members of the ISO MSC shall be compensated on such basis as the ISO Governing Board shall from time to time determine.

Members of the ISO MSC shall receive prompt reimbursement for all expenses reasonably incurred in the execution of their responsibilities under this MMIP 5.

MMIP 5.5 **Liability for Damages**

As provided in Section 14.1 and 14.2 of the ISO Tariff, the Market Surveillance Unit, the ISO MSC, the ISO CEO and other ISO staff shall not be liable to any Market Participant under any circumstances whatsoever for any matter described in those sections, including but not limited to any financial loss or loss of economic advantage resulting from the performance or non-performance by such ISO entities of their functions under this Protocol.

MMIP 6 **SPECIFIC FUNCTIONS OF ISO MARKET SURVEILLANCE COMMITTEE (ISO MSC)**

MMIP 6.1 **Information Gathering and Evaluation Criteria**

The ISO MSC shall review the initial catalogs of information and data and of evaluation criteria developed by the Market Surveillance Unit pursuant to MMIP 4 and shall propose such changes, additions or deletions to such catalogs or items therein as it sees fit. In so doing, the ISO MSC shall have full discretion to specify database items or evaluation criteria for inclusion in the pertinent catalog.

MMIP 6.2 **Evaluation of Information**

The ISO MSC may, upon request of the Market Surveillance Unit, the ISO CEO or the ISO Governing Board, or on its own volition, evaluate such information or data, including as may be collected by the Market Surveillance Unit on the basis of the evaluation criteria developed by the Market Surveillance Unit or on such further articulated evaluation criteria developed by the ISO MSC.

APPENDIX A

ISO Market Monitoring Plan

Market Mitigation Measures

1 PURPOSE AND OBJECTIVES

1.1 These ISO market power mitigation measures ("Mitigation Measures") are intended to provide the means for the ISO to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the ISO Real Time Market while avoiding unnecessary interference with competitive price signals. These Mitigation Measures are intended to minimize interference with an open and competitive market, and thus to permit, to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the Mitigation Measures authorize the mitigation only of specific conduct that exceeds well-defined thresholds specified below.

1.2 In addition, the ISO shall monitor the markets it administers for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the ISO. If the ISO identifies any such conduct, and in particular conduct exceeding the thresholds for presumptive market effects specified below, it shall make a filing under Section 205 of the Federal Power Act, 16 U.S.C. § 824d, with FERC requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the ISO believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the ISO's justification for imposing that mitigation measure.

2 CONDUCT WARRANTING MITIGATION

2.1 Definitions

The following definitions are applicable to this Appendix A:

"Economic Market Clearing Prices" are the Market Clearing Prices for a particular resource at the location of that particular resource at the time the resource was either Scheduled or was Dispatched by the ISO. Economic Market Clearing Prices may originate from the Day-Ahead Energy market, the Hour-Ahead Energy market (when these markets are in place), or ISO real-time Imbalance Energy market. The Economic Market Clearing Price for the ISO real-time Imbalance Energy market shall be the Dispatch Interval Ex Post Price, unless the resource cannot change output level within the hour (i.e., the resource is not amenable to intra-hour real-time Dispatch instructions), or it is a System Resource. Economic Market Clearing Prices for the ISO real-time Imbalance Energy market for resources that cannot change output level within one Dispatch Interval and System Resources shall be the simple average of the relevant Dispatch Interval Ex Post Prices for each hour.

"Electric Facility" shall mean an electric resource, including a Generating Unit, System Unit, or a Participating Load.

2.2 Conduct Subject to Mitigation

Mitigation Measures may be applied: (i) to the bidding, scheduling, or operation of an "Electric Facility"; or (ii) as specified in Section 2.4 below.

2.3 Conditions for the Imposition of Mitigation Measures

2.3.1 In general, the ISO shall consider a Market Participant's conduct to be inconsistent with competitive conduct if the conduct would not be in the economic interest of the Market Participant in the absence of market power. The categories of conduct that are inconsistent with competitive conduct include, but may not be limited to, the three categories of conduct specified in Section 2.4 below.

2.4 Categories of Conduct that May Warrant Mitigation

2.4.1 The following categories of conduct, whether by a single firm or by multiple firms acting in concert, may cause a material effect on prices or generally the outcome of the ISO Real Time Market if exercised from a position of market power. Accordingly, the ISO shall monitor the ISO Markets for the following categories of conduct, and shall impose appropriate Mitigation Measures if such conduct is detected and the other applicable conditions for the imposition of Mitigation Measures are met:

(1) Physical withholding of an Electric Facility, in whole or in part, that is, not offering to sell or schedule the output of or services provided by an Electric Facility capable of serving an ISO Market. Such withholding may include, but not be limited to: (i) falsely declaring that an Electric Facility has been forced out of service or otherwise become totally or partially unavailable, (ii) refusing to offer bids or schedules for an Electric Facility when it would be in the economic interest, absent market power, of the withholding entity to do so, (iii) declining real-time bids called upon by the ISO (unless the ISO is informed in accordance with established procedures that the relevant resource for which the bid is submitted has undergone a forced outage or derate), or (iv) operating a Generating Unit in real time to produce an output level that is less than the ISO's Dispatch instruction.

(2) Economic withholding of an Electric Facility, that is, submitting bids for an Electric Facility that are unjustifiably high (relative to known operational characteristics and/or the known operating cost of the resource) so that: (i) the Electric Facility is not or will not be dispatched or scheduled, or (ii) the bids will set a Market Clearing Price.

(3) Uneconomic production from an Electric Facility, that is, increasing the output of an Electric Facility to levels that would otherwise be uneconomic in order to cause, and obtain benefits from, a transmission constraint.

2.4.2 Mitigation Measures may also be imposed to mitigate the market effects of a rule, standard, procedure, design feature, or known software imperfection of an ISO Market that allows a Market Participant to manipulate market prices or otherwise impair the efficient operation of that market, pending the revision of such rule, standard, procedure design feature, or software defect to preclude such manipulation of prices or impairment of efficiency.

2.4.3 Taking advantage of opportunities to sell at a higher price or buy at a lower price in a market other than an ISO Market shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

2.4.4 The ISO shall monitor ISO Markets for other categories of conduct, whether by a single firm or by multiple firms acting in concert, that have material effects on prices in an ISO Market or other payments. The ISO shall: (i) seek to amend the foregoing list as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of the ISO Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the FERC as may be appropriate.

3 CRITERIA FOR IMPOSING MITIGATION MEASURES

3.1 Identification of Conduct Inconsistent with Competition

Conduct that may potentially warrant the imposition of a mitigation measure includes the categories described in Section 2.4 above. The thresholds listed in Section 3.1.1 below shall be used to identify substantial departures from competitive conduct indicative of an absence of workable competition.

3.1.1 Conduct Thresholds for Identifying Economic Withholding

The following thresholds shall be employed by the ISO to identify economic withholding that may warrant the mitigation of the bid from a resource and shall be determined with respect to a reference level determined as specified in Section 3.1.1.1:

For Energy Bids to be Dispatched as Imbalance Energy through the RTD Software: the lower of a 200 percent increase or $100/MWh increase in the bid with respect to its Reference Level.

being examined by the ISO, and provided the Market Participant has provided sufficient data on a unit's energy limitations and operating costs (opportunity cost for energy limited resources) in accordance with specifications provided by the ISO.

4. The mean of the Economic Market Clearing Prices for the units' relevant location (Zone or node commensurate with the pricing granularity in effect) during the lowest-priced 25 percent of the hours that the unit was dispatched or scheduled over the previous 90 days for peak and off-peak periods, adjusted for changes in fuel prices; or
5. If sufficient data do not exist to calculate a reference level on the basis of the first, second, or fourth methods and the third method is not applicable or an attempt to determine a reference level in consultation with a Market Participant has not been successful, the ISO shall determine a reference level on the basis of:
   i. the ISO's estimated costs of an Electric Facility, taking into account available operating costs data, opportunity cost, and appropriate input from the Market Participant, and the best information available to the ISO; or
   ii. an appropriate average of competitive bids of one or more similar Electric Facilities.

(b) The reference levels ($/MWh bid price) for the different bid segments of each resource (or import bid curve of a Scheduling Coordinator at a Scheduling Point) shall be made monotonically non-decreasing by the ISO by proceeding from the lowest MW bid segment moving through each higher MW bid segment. The reference level of each succeeding bid segment shall be the higher of the reference level of the preceding bid segment or the reference level determined according to paragraph (a) above.

3.2 Material Price Effects

3.2.1 Market Impact Thresholds

In order to avoid unnecessary intervention in the ISO Market, Mitigation Measures for economic withholding shall not be imposed unless conduct identified as specified above causes or contributes to a material change in one or more of the ISO Market Clearing Prices (MCPs). Initially, the thresholds to be used by the ISO to determine a material price effect shall be as follows:

For Energy Bids to be Dispatched as Imbalance Energy through the RTD Software: the lower of an increase of 200 percent or $50 per MWh in the projected Hourly Ex Post Price at any location (Zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff.

For Energy Bids to be Dispatched out of economic merit order to manage Intra-Zonal Congestion: if the price of the bid is $50/MWh or 200 percent greater than the Dispatch Interval Ex Post Price at that location (Zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff.

Accepted and justified bids above the applicable soft cap, as set forth in Section 28.1.2 of this Tariff, will not be eligible to set the Market Clearing Price. Such bids shall be included in the Market Impact test, however, and, for purposes of this test only, shall be assumed to be eligible to set the Market Clearing Price.

3.2.2 Price Impact Analysis

3.2.2.1 *Bids to be Dispatched as Imbalance Energy.*

The ISO shall determine the effect on prices of questioned conduct through automated computer modeling and analytical methods. An Automatic Mitigation Procedure (AMP) shall identify bids that have exceeded the conduct thresholds and shall compute the change in projected Hourly Ex Post Prices as a result of simultaneously setting all such bids to their Reference Levels. If a change in the projected Hourly Ex Post Price exceeds the Impact threshold stated in Section 3.2.1, those bids would be kept mitigated at their default bid levels as specified in Section 4.2.2 below.

3.2.2.2 Bids to be Dispatched out of economic merit order to manage Intra-Zonal Congestion. If the price of the bid is $50/MWh or 200 percent greater than the Dispatch Interval Ex Post Price at that location (Zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff, the bid price shall be mitigated to the reference price and the Scheduling Coordinator for that resource shall be paid the greater of the reference price or the relevant Dispatch Interval Ex Post Price. Bids mitigated in accordance with this Section 3.2.2.2 shall not set the Dispatch Interval Ex Post Price.

3.2.3 Section 205 Filings

In addition, the ISO shall make a filing under Section 205 of the Federal Power Act with FERC seeking authorization to apply an appropriate mitigation measure to conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Section 3.1.1 above, unless the ISO determines, from information provided by the Market Participant or Parties that would be subject to mitigation or other information available to the ISO that the conduct is attributable to legitimate competitive market forces or incentives. The following are examples of conduct that are deemed to depart significantly from the conduct that would be expected under competitive market conditions:

(1) bids that vary with unit output in a way that is unrelated to the known performance characteristics of the unit, or

(2) bids that vary over time in a manner that appears unrelated to the change in the unit's performance or to changes in the supply environment that would induce additional risk or other adverse shifts in the cost basis.

The conducts listed above are intended to be examples rather than a comprehensive list.

3.3 Consultation with a Market Participant

If a Market Participant anticipates submitting bids in an ISO Market administered by the ISO that will exceed the thresholds specified in Section 3.1 above for identifying conduct inconsistent with competition, the Market Participant may contact the ISO to provide an explanation of any legitimate basis for any such changes in the Market Participant's bids. If a Market Participant's explanation of the reasons for its bidding indicates to the satisfaction of the ISO, that the questioned conduct is consistent with competitive behavior, no further action will be taken. Upon request, the ISO shall also consult with a Market Participant with respect to the information and analysis used to determine reference levels under Section 3.1.1 above for that Market Participant.

4 MITIGATION MEASURES

4.1 Purpose

If conduct is detected that meets the criteria specified in Section 3, the appropriate mitigation measures described in this Section 4 shall be applied by the ISO. The conduct specified in Section 3.1.1 shall be remedied by the prospective application of a default bid measure as described in Section 4.2 for the specific hour that they violate the price and market impact thresholds.

4.2 Sanctions for Economic Withholding

4.2.1 Default Bid

A default bid shall be designed to cause a Market Participant to bid as if it faced workable competition during a period when: (i) the Market Participant does not face workable competition and (ii)

has responded to such condition by engaging in the economic withholding of an Electric Facility. In designing and implementing default bids, the ISO shall seek to avoid causing an Electric Facility to bid below its marginal cost.

4.2.2 Implementation

(a) If the criteria contained in Section 3 are met, the ISO may substitute a default bid for a bid submitted for an Electric Facility. The default bid shall establish a maximum value for each component of the submitted bid, equal to a reference level for that component determined as specified in Section 3.1.1 above.

(b) The Mitigation Measures will be applied to 1) all incremental bids submitted to the real-time Imbalance Energy market during the pre-dispatch process prior to the real-time Imbalance Energy market based on the projected real-time MCPs that are computed during this process; and 2) to the Day-Ahead and the Hour-Ahead Energy markets when these markets are made operational.

(c) An Electric Facility subject to a default bid shall be paid the MCP applicable to the output from the facility. Accordingly, a default bid shall not limit the price that a facility may receive unless the default bid determines the MCP applicable to that facility.

(d) The ISO shall not use a default bid to determine revised MCPs for periods prior to the imposition of the default bid, except as may be specifically authorized by FERC.

(e) The Mitigation Measures shall not be applied to Energy Bids projected to be Dispatched as Imbalance Energy through the RTD Software in the hours in which all Zonal Ex Post Prices are projected to be below $91.87/MWh. If the Zonal Dispatch Interval Ex Post Price is projected to be above $91.87/MWh in any ISO Zone, the Mitigation Measures shall be applied to all bids, except those from System Resources, in all ISO Zones. The ISO will apply Mitigation Measures to all bids taken out of merit order to address Intra-Zonal Congestion.

(f) The Mitigation Measures shall not be applied to bids below $25/MWh.

(g) The posting of the MCP may be delayed if necessary for the completion of automated mitigation procedures.

(h) Bids not mitigated under these Mitigation Measures shall remain subject to mitigation by other procedures specified in the ISO Tariff as may be appropriate.

4.3 Sanctions for Physical Withholding

The ISO may report a Market Participant the ISO believes to have engaged in physical withholding, including providing the ISO false information regarding the derating or outage of an Electric Facility, to the Federal Energy Regulatory Commission in accordance with Section 2.3.3.9.5 of the ISO Tariff. In addition, a Market Participant that fails to operate a Generating Unit in conformance with ISO Dispatch Instructions shall be subject to the penalties set forth in Section 11.2.4.1.2 of the ISO Tariff.

4.4 Duration of Mitigation Measures

Bids will be mitigated only in the specific hour that they violate the price and market impact thresholds.

5 FERC-ORDERED MEASURES

In addition to any mitigation measures specified above, the ISO shall administer, and apply when appropriate in accordance with their terms, such other mitigation measures as it may be directed to implement by order of the FERC.

6 DISPUTE RESOLUTION

OUTAGE COORDINATION PROTOCOL (OCP)

OCP 1 OBJECTIVES, DEFINITIONS, AND SCOPE

OCP 1.1 Objectives

The objective of the OCP is to enable the ISO to coordinate maintenance outages as far as possible in advance to allow the ISO to maintain System Reliability and to minimize the quantity and effect of Congestion on the ISO Controlled Grid and Interconnections.

OCP 1.1.1 The Role of the ISO

The ISO Tariff authorizes the ISO to coordinate outage schedules for maintenance, repair and construction of Generating Units, sections of the ISO Controlled Grid, and Interconnections. This Protocol is designed to enable the ISO to perform this role.

The Facility Owner shall remain solely and directly responsible for the performance of all maintenance work, whether on energized or deenergized facilities, including all activities related to providing a safe working environment.

OCP 1.1.2 ISO Outage Coordination Office

The ISO Outage Coordination Office will be operational Monday through Friday, except holidays, and will accept, schedule, and approve or deny Maintenance Outage requests as necessary for the reliable operation of the ISO Controlled Grid. The Outage Coordination Office is located in Folsom. Each office and the areas of responsibility of that office are detailed in the most recent version of the applicable ISO Operating Procedures, which are posted on the ISO Home Page.

OCP 1.2 Definitions

OCP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix refers to a Section or an Appendix of the ISO Tariff unless otherwise indicated. References to OCP are to this Protocol or to the stated paragraph of this Protocol.

OCP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meaning set opposite them:

"Final Approval" means a statement of consent by the ISO Control Center to initiate a scheduled Outage.

OCP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) Unless the context otherwise requires, if the provisions of this Protocol and that of an existing contract conflict, the existing contract will prevail to the extent of the inconsistency.

(c) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(d) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(e) This Protocol shall be effective as of the ISO Operations Date.

(f) The Operating Procedures referenced in this Protocol, as may be amended from time to time, shall be posted on the ISO Home Page and such references in this Protocol shall be to the Operating Procedures then posted on the ISO Home Page.

SCHEDULES AND BIDS PROTOCOL

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SCHEDULES AND BIDS PROTOCOL (SBP)

SBP 1 OBJECTIVES, DEFINITIONS AND SCOPE

SBP 1.1 *Objectives*

The objectives of this Protocol are:

(a) to require the provision of scheduling data to enable the ISO to undertake its scheduling process as described in the ISO Tariff and in the Scheduling Protocol (SP) taking into account the exercise of Firm Tranmission Rights and rights under Existing Contracts for transmission service;

(b) to require the provision of Ancillary Services Schedules and bidding data required by the ISO to enable the ISO to conduct its Ancillary Services auction as described in the ISO Tariff and in the SP; and

(c) to specify the contents of Schedules and to specify in detail the bidding data referred to in the ISO Tariff. The scheduling process and timing of the submission of data referred to are set forth in the SP.

SBP 1.2 *Definitions*

SBP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is to a Section or an Appendix of the ISO Tariff unless otherwise specified. References to SBP are to this Protocol or to the stated paragraph of this Protocol.

SBP 1.2.2 [Not Used]

SBP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

Unit will include Transmission Losses associated with the unit's Final Hour-Ahead Schedule as determined by the relevant GMM;

(h) Congestion Management flag – "Yes" indicates that any Adjustment Bid submitted under item (I) below should be used in the Day-Ahead or Hour-Ahead Market;

SBP 2.1.3 External Import/Export Section of a Balanced Schedule and Adjustment Bid Data

The external import/export section of a Balanced Schedule will include the following information for each import or export:

(a) SC's ID code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) Scheduling Point (the name);

(d) type of Schedule: Preferred or Revised (refer to the SP for details);

(e) interchange ID (the name of the selling entity, the buying entity, and a numeric identifier);

(f) Energy type – firm (FIRM), non-firm (NFRM) or dynamic (DYN) or Wheeling (WHEEL);

(g) external Control Area ID;

(h) priority type, if applicable, to the Settlement Period (use OTHER if scheduling the use of Existing Contract rights or RLB_MUST_RUN for Reliability Must-Run Generation);

(i) contract reference number for Reliability Must-Run Generation or Existing Contract (or set of interdependent Existing Contracts);

(j) contract type – transmission (TRNS), Energy (ENGY) or both (TR_EN);

(k) Schedule ID (NERC ID number);

(l) Congestion Management flag - "Yes" indicates that any Adjustment Bid submitted for an external import/export in item (q) below should be used;

(m) publish Adjustment Bid flag, which will not be functional on the ISO Operations Date. In the future, "Yes" will indicate that the SC wishes the ISO to publish its Adjustment Bids;

(n) complete WECC tag;

(o) hourly scheduled external imports/exports in MWh (the ISO will multiply these values by the hourly Generation Meter Multipliers), including any zero values, for each Settlement Period of the Trading Day (in the case of a Day-Ahead Schedule) and for the relevant Settlement Period (in the case of an Hour-Ahead Schedule) and with external imports into the ISO Controlled Grid reported as negative quantities and external exports from the ISO Controlled Grid reported as positive quantities;

(p) the MW and $/MWh values for each external import/export for which an Adjustment Bid is being submitted consistent with SBP 4; and

(q) for dynamically scheduled imports only, the transmission loss self-provision flag (LOSS_CMP_FLG): "Yes" indicates that Dispatch Instructions provided to the resource will include Transmission Losses associated with the resource's Final Hour-Ahead Schedule as determined by the relevant GMM.

SBP 2.1.4 Inter-Scheduling Coordinator Energy Trades ("Internal Imports/Exports") Section of a Balanced Schedule

In the event of an Inter-Scheduling Coordinator Energy Trade, the SCs who are parties to that trade must agree on a Zone in which the trade will be deemed to take place ("Trading Zone") and notify the ISO accordingly. The purpose of designating a Trading Zone is to provide for the allocation of Usage Charges which may arise in connection with the trade. The Inter-Scheduling Coordinator Energy Trades section of a Schedule will include the following information for each Inter-Scheduling Coordinator Trade:

(a) SC's ID code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) trading SC (buyer or seller);

(d) type of Schedule: Preferred or Revised (refer to the SP for details);

(e) Trading Zone;

(f) Schedule type – Energy (ENGY);

(g) hourly scheduled MWh, including any zero values, for each Settlement Period of the Trading Day (in the case of a Day-Ahead Schedule) and for the relevant Settlement Period (in the case of an Hour-Ahead Schedule), with internal imports into the SC reported as negative quantities and internal exports from the SC reported as positive quantities;

(h) Congestion Management flag – "Yes" indicates that Adjustment Bid submitted under (k) below should be used;

(i) publish Adjustment Bid flag – "Yes" indicates that the SC wishes the ISO to publish its Adjustment Bid.

(j) the Generating Unit or Dispatchable Load that is the source or recipient of Energy traded; and

(k) the MW and $/MWh values for each Generating Unit or Dispatchable Load that is the source or recipient of Energy traded.

(although the contract reference numbers need not be listed in any particular order since they will be arranged by the ISO's scheduling program to connect the "from Zone" to "to Zone");

(f) Usage ID (a unique identifier that allows a SC to submit multiple usages for a given Inter-Zonal Interface);

(g) Contract usage, in hourly scheduled MW, for the 24 hours of the Trading Day (for Generators, contract usage can be either positive or negative [i.e., for pumps]; for loads, contract usage must be positive; for external imports and inter-Scheduling Coordinator trade imports, contract usage must be negative; for external exports, contract usage must be positive). Each contract usage amount must be less than or equal to the amount of Existing Contract rights specified by the relevant Participating Transmission Owner(s) of Firm Transmission Rights, whichever the case may be. Additionally, any Adjustment Bids that may also be submitted for any particular resource (source or sink) that is also identified on a contract usage template must not overlap the contract usages specified for a particular resource in a contract usage template;

(h) Priority usage, relative to all contract usages specified in a SC's Balanced Schedule, as expressed on a scale of one to ten (with 1 having least priority and 10 having highest priority). For Existing Contracts, this priority will be used to adjust usage quantities when scheduled usages exceed the reserved existing transmissions reservations; and

(i) Sources or sinks, of hourly scheduled MWH (in the case of Energy usages) or MW (in the case of Ancillary Services usages), specified on the contract usage template must be balanced (except for Ancillary Services which need not be specified with sinks). Each Energy schedule or Ancillary Service bid or self-provided schedule associated with a particular source or sink must have an hourly usage schedule that is greater than or equal to the amounts specified on contract usage templates. The source/sink section of a contract usage template will include the following information (up to five combinations of sources and sinks can be specified on a single contract usage template if an SC is submitting the templates in accordance with SBP 7.2(a), or up to 20 combinations of sources and sinks if an SC is submitting the templates in accordance with SBP 7.2(b) or SBP 7.2(c));

(1) Type of resource – Generation (GEN), load (LOAD), interchange (INTRCHNGE) or inter-Scheduling Coordinator trade (INTER_SC);

(2) Resource_ID – generator_ID, load_ID, tie_point or trading SC;

(3) Resource_ID2 (required only for individual interchange schedules and inter-Scheduling Coordinator trades);

(4) Energy type – firm (FIRM), non-firm (NFIRM), Wheeling (WHEEL), dynamic (DYN), Energy (ENGY), Spinning Reserve (CSPN), Non-Spinning Reserve (CNSPN) or Replacement Reserve (CRPLC); and

(5) Hourly scheduled Energy or Ancillary Service, utilizing the same sign convention as set forth in (g) above.

SBP 2.1.7 No Scheduling Coordinator shall submit a Circular Schedule. The ISO may periodically provide examples of such Circular Schedules under the ISO Home Page.

SBP 2.2 Validation of Balanced Schedules

Each SC will be assigned a workspace within the ISO's scheduling system. Each workspace will have a work area for Day-Ahead and Hour-Ahead Schedules, Adjustment Bids and Supplemental Energy bids. The SC shall only be allowed to access and manipulate its Schedule and bid data within this workspace. Each area is organized into segments. A segment is used to hold the SC's Schedules relating to the same Trading Day. The Schedule validation process is divided into two stages. The ISO shall carry out the first stage validation immediately after it has received a Schedule. The ISO shall carry out the second stage validation ten (10) minutes before (pre-validation) and immediately after each deadline (as specified in the SP) for submission of Schedules. However, a SC can also initiate the stage two validation at any time prior to that deadline, as described in more detail in the SP. If the SC adds a new Schedule or modifies an existing Schedule, that Schedule must be re-validated. SCs must comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for Balanced Schedules.

SBP 2.2.1 Stage One Validation

During stage one validation, each incoming Schedule will be validated to verify proper content, format and syntax. The ISO will check that the SC had not exceeded its Security Amount and verify that the SC is certified in accordance with the ISO Tariff. The ISO will further verify that the SC has inputted valid Generating Unit and Demand location identification. Scheduled Reliability Must-Run Generation will be verified against the contract reference numbers in the ISO's Scheduling Coordinator database. A technical validation will be performed verifying that a scheduled Generating *Unit's* output is not beyond it's declared capacity and/or operating limits. If there is an error found during stage one validation, the SC will be notified immediately through WEnet. The SC can then look at the notification messages to review the detailed list of errors, make changes, and resubmit the Schedule if it is still within the timing requirements of the SP. Additionally, if the ISO detects an invalid contract usage (of either Existing Contract rights or Firm Transmission Rights), the ISO will issue an error message in similar manner to the SC and allow the SC to view the message(s), to make changes, and to resubmit the contract usage template(s) if it is still

within the timing requirements of the SP. The SC is also notified of successful validation via WEnet.

SBP 2.2.2 Stage Two Validation

During stage two validation, Schedules will be checked to determine whether each SC's aggregate Generation and external imports (adjusted for Transmission Losses) and Inter-Scheduling Coordinator Energy Trades (whether purchases or sales) equals the SC's aggregate Demand Forecast, including external exports. The SC must take into account the applicable Generation Meter Multipliers (GMMs) as described in the SP. The SC will be notified if the counterpart trade to any Inter-Scheduling Coordinator Ancillary Service Trade has not been submitted, or is infeasible (i.e. if both SCs are selling or both are buying). Mismatches in Inter-Scheduling Coordinator Ancillary Service Trades shall be adjusted to be equal to the amount specified by the selling SC. This validation is performed in accordance with the timing requirement described in the SP. An SC can also check whether its Schedules will pass the ISO's stage two validation by manually initiating validation of its Preferred Schedules or Revised Schedules, as described in the SP, at any time prior to the deadline for submission of Preferred Schedules or Revised Schedules (as the case may be). It is the SC's responsibility to perform such checks, if desired. The SC will be notified immediately through WEnet of any validation errors. For each error detected, an error message will be generated by the ISO in the SC's notification screen which will specify the nature of the error. If the ISO detects a mismatch in Inter-Scheduling Coordinator Trades, the ISO will notify both SCs of the mismatch in Energy quantity and/or location. The SC can then look at the notification messages to review the detailed list of errors, make changes, and resubmit the Schedule if it is still within the timing requirements of the SP. The SC is also notified of successful validation via WEnet.

SBP 2.3 The Generation section of a Balanced Schedule, and any associated Adjustment Bids, must accurately reflect the physical capability of each Generating Unit identified in the Schedule (including each Generating Unit's ability to ramp from one hour to the next). For example, a 500 MW Generating Unit specified with a ramp rate of 2 MW/min and an operating point of 100 MWh for the current operating hour is not physically capable of generating 300 MWh in the next operating hour. Likewise, Adjustment Bids sumbitted for a Generating Unit, applicable to a particular operating hour, should be physically achievable within the applicable operating hour.

SBP 3 EXISTING CONTRACTS FOR TRANSMISSION SERVICE

SBP 3.1 Application of SBP 3 to Rights under Existing Contracts

SBP 3.1.1 Existing Rights

The provisions of Sections 2.4.3 and 2.4.4 of the ISO Tariff shall, with respect to the exercise of Existing Rights following the ISO Operations

instruction and that references a single Existing Contract or a set of interdependent Existing Contracts; the provisions of SBP 3.4 will apply to the validation of scheduled uses of Existing Contract transmission rights);

(b) whether the instruction can be exercised independent of the ISO's day-to-day involvement (Yes/No);

(c) name of an operational single point of contact for instructions and a 24-hour a day telephone number for the Responsible PTO;

(d) name(s) and number(s) of Existing Contract(s);

(e) path name(s) and location(s) (described in terms of the Zones in which the point(s) of receipt and point(s) of delivery are located);

(f) names of the party(ies) to the Existing Contract(s);

(g) SC ID code: the ID number of the SC who will submit Schedules which make use of the Existing Contract(s) for the party(ies) indicated in (f);

(h) type(s) of rights, by rights holder, by Existing Rights;

(i) type(s) of service, by rights holder, by Existing Contract (firm, conditional firm, or non-firm), with priorities for firm and conditional firm transmission services indicated in Schedules using Adjustment Bids as described in the SP;

(j) amount of transmission service, by rights holder, by Existing Contract expressed in MW;

(k) for Day-Ahead scheduling purposes, the time of the day preceding the Trading Day at which the SC submits Schedules to the ISO referencing the Existing Contract(s) identified in the instructions;

(l) for Hour-Ahead or real-time scheduling purposes, the number of minutes prior to the start of the Settlement Period of delivery at which the SC may submit Schedule adjustments to the ISO regarding the Existing Rights under the Existing Contract(s) identified in the instructions;

(m) whether or not real-time modifications to Schedules associated with Existing Rights are allowed at any time during the Settlement Period;

(n) Service period(s) of the Existing Contract(s);

(o) any special procedures which would require curtailments to be implemented by the ISO in any manner different than that specified in SBP 3.3.2. Any such instructions submitted to the ISO must be clear, unambiguous, and not require the ISO to make any judgments or interpretations as to the meaning,

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Generating Unit or System Unit ID code;

(e) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(f) upward and downward range of Generating Unit or System Unit capacity over which the Generating Unit or System Unit is offering to provide Regulation;

(g) Generating Unit or System Unit operating limits (high and low MW);

(h) Generating Unit or System Unit ramp rate (MW/minute); and

(i) bid price for Regulation capacity ($/MW).

SBP 5.1.1.2 Regulation: External Imports

Each SC desiring to self-provide Regulation or to participate in the ISO's Regulation auction will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:

(a) type of schedule: (Regulation Ancillary Service);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Scheduling Point (the name)

(e) interchange ID code (the name of the selling entity, buying entity and a numeric identifier);

(f) external Control Area ID;

(g) Schedule ID (NERC ID number);

(h) complete WECC tag;

(i) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(j) in the case of Existing contracts, the applicable contract reference number;

(k) upward and downward range of System Resource capacity over which the System Resource is offering to provide Regulation;

(l) System Resource operating limits (high and low MW);

(g) Schedule ID (NERC ID number);

(h) complete WECC tag;

(i) preferred bid flag, which must be set to "NO", indicating a self-provided schedule, until such time as the ISO's scheduling system is able to support Ancillary Services bids from external imports/exports;

(j) export flag, a "YES" indicates an external export and a "NO" indicates an external import;

(k) In the case of Existing Contracts, the applicable contract reference number;

(l) Spinning Reserve capacity (MW);

(m) ramp rate (MW/minute); and

(n) bid price for Spinning Reserve capacity ($/MW).

SBP 5.1.3 *Non-Spinning Reserve*

SBP 5.1.3.1 Non-Spinning Reserve: Generating Units or System Units

Each SC desiring to self-provide Non-Spinning Reserve or to participate in the ISO's Non-Spinning Reserve auction will submit the following information for each relevant Generating Unit or System Unit for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Non-Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Generating Unit or System Unit ID code;

(e) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(f) time to synchronize following notification (less than ten (10) *minutes mandatory*);

(g) Non-Spinning Reserve capacity available within ten (10) minutes following notification (MW);

(h) Generating Unit or System Unit operating limits (high and low MW);

(i) Generating Unit or System Unit ramp rate (MW/minute); and

(j) bid price for Non-Spinning Reserve capacity ($/MW).

SBP 5.1.3.2 Non-Spinning Reserve: Curtailable Demands

Each SC desiring to self-provide Non-Spinning Reserve or to participate in the ISO's Non-Spinning Reserve auction will submit the following information for each relevant Curtailable Demand for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Non-Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead and Hour-Ahead) and Trading Day;

(d) available Curtailable Demand ID code;

(e) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(f) maximum allocation curtailment duration (hours) (CURT_HR);

(g) time to interruption following notification (minutes);

(h) amount of Curtailable Demand that can be interrupted within ten (10) minutes following notification (MW); and

(i) bid price for Non-Spinning Reserve capacity ($/MW).

SBP 5.1.3.3 Non-Spinning Reserve: External Imports/Exports

Each SC desiring to bid or self-provide Non-Spinning Reserve will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Non-Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Scheduling Point (the name);

(e) interchange ID code (the name of the selling entity, buying entity and a numeric identifier);

(f) external Control Area ID;

(g) Schedule ID (NERC ID number);

(h) complete WECC tag;

(i) preferred bid flag, which must be set to "NO", indicating a self-provided schedule;

SBP 5.1.4.2 Replacement Reserve: Curtailable Demands

Each SC desiring to self-provide Replacement Reserve or to participate in the ISO's Replacement Reserve auction will submit the following information for each relevant Curtailable Demand for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Replacement Reserve Ancillary Service (ANC_SRVC) or Revised Replacement Reserve Ancillary Service (REVISED_ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Curtailable Demand ID code;

(e) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(f) maximum allocation curtailment duration (hours) (CURT_HR);

(g) time to reduction following notification (minutes);

(h) amount of Curtailable Demand that can be interrupted within sixty (60) minutes following notification (MW);

(i) Curtailable Demand reduction rate (MW/minute); and

(j) bid price for Replacement Reserve capacity ($/MW).

SBP 5.1.4.3 Replacement Reserve: External Imports

Each SC desiring to bid or self-provide Replacement Reserve will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Replacement Reserve Ancillary Service (ANC_SRVC) or Revised Replacement Reserve Ancillary Service (REVISED_ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Scheduling Point (the name);

(e) interchange ID code (the name of the selling entity, buying entity and a numeric identifier);

(f) external Control Area ID;

(g) Schedule ID (NERC ID number);

(h) complete WECC tag;

SBP 5.2.3 Validation Checks

The ISO's stage one validation checks are performed automatically whenever Ancillary Services Schedules and bids are submitted, as described in the SP. The ISO's stage two validation is performed automatically in accordance with the timing requirements described in the SP. A SC can also check whether its Ancillary Services Schedules and bids will pass the ISO's stage two validation by manually initiating validation of its Ancillary Services Schedules and bids, as described in the SP, at any time prior to the deadline for submission of Ancillary Services Schedules and bids. It is a SC's responsibility to perform such checks.

SBP 5.3 Buy Back of Ancillary Services

A Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace such capacity to the extent scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or to the extent the Ancillary Service associated with a Generating Unit, Curtailable Demand, or System Resource successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduing Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replaced Ancillary Service shall be at the Market Clearing Price in the Hour-Ahead Market for the same Settlement Period for the Ancillary Service capacity concerned.

SBP 6 ENERGY BIDS

SCs must submit Energy Bids for resources providing Spinning, Non-Spinning, or Replacement Reserves. The upper portion of the Energy Bid that corresponds to the resource's available capacity up to the highest operating limit, shall be allocated to any awarded or self-provided Ancillary Services in the following order from higher to lower capacity: a) Regulation Up; b) Spinning Reserve; c) Non-Spinning Reserve; and d) Replacement Reserve. For resources providing Regulation Up, the upper regulating limit shall be used if it is lower than the highest operating limit. The remaining portion of the Energy Bid, if there is any, shall constitute Supplemental Energy. Supplemental Energy bids are available to the ISO for procurement and use for Imbalance Energy, additional Voltage Support and Congestion Management in the Real Time Market.

SBP 6.1 Content of Energy Bids

SBP 6.1.1 Generation Section of Energy Bid Data

Each SC offering Spinning, Non-Spinning, or Replacement Reserve, or Supplemental Energy to the ISO will submit the following information for each Generating Unit for each Settlement Period:

(a) SC's ID code;

(b) name of Generating Unit;

(c) Generating Unit operating limits (high and low MW);

(d) Generating Unit operational ramp rate in MW/minute;

(e) Generating Unit startup time function in minutes;

(f) Generating Unit startup cost function in $/start;

(g) Generating Unit Minimum Load Cost in $/hr; and

(h) the MW and $/MWh values for each Generating Unit for which a Supplemental Energy bid is being submitted consistent with this SBP 6.

A Physical Scheduling Plant shall be treated as a single Generating Unit for Supplemental Energy bid purposes.

SBP 6.1.2 Demand Section of Energy Bid Data

Each SC offering Spinning, Non-Spinning, or Replacement Reserve, or Supplemental Energy to the ISO will submit the following information for each Demand for each Settlement Period:

(a) SC's ID code;

(b) name of Demand;

(c) Demand shutdown time in minutes;

(d) Demand shutdown cost in $/start;

(e) Demand minimum curtailed load cost in $/hr; and

(f) the MW and $/MWh values for each Demand for which a Supplemental Energy bid is being submitted consistent with this SBP 6.

SBP 6.1.3 External Import Section of Energy Bid Data

Each SC offering Spinning, Non-Spinning, or Replacement Reserve, or Supplemental Energy to the ISO will submit the following information for each external import for each Settlement Period;

(a) SC's ID code;
(b) name of Scheduling Point;
(c) interchange ID (the name of the selling entity, the buying entity, and a numeric identifier);
(d) external Control Area ID;
(e) Schedule ID (NERC ID number);
(f) complete WECC tag;
(g) operational ramp rate (MW/minute); and
(h) the MW and $/MWh values for each external import for which a Supplemental Energy bid is being submitted consistent with this SBP 6; and
(i) minimum block of hours that bid must be dispatched; and
(j) Flag indicating the bid must is capable available for intra-hour Redispatch. If this flag is set to no then the bid is indicating that the bid must be pre-dispatched and not re-dispatched during the real-time operating hour.

SBP 6.2 Format of Energy Bids

The SC's Final Hour-Ahead Schedule for each resource must be within the range of the Energy Bids. The minimum MW output level specified for a resource, which may be zero MW (or negative for pumped storage resources), and the maximum MW output level specified for a resource must be physically achievable by the resource. All submitted Energy Bids must be in the form of a monotonically increasing staircase

- The startup cost for each segment must not be negative and must not exceed the startup cost of the corresponding segment of the cost-based startup cost function, as registered in the Master File for the relevant resource. For gas-fired resources, the cost-based startup cost function shall be derived from the startup fuel function, as registered in the Master File for the relevant resource, and the applicable gas price index as approved by FERC.
- The startup cost function must be strictly monotonically increasing, i.e., the startup cost must increase as down time increases.

For Curtailable Demand, a single shutdown cost in $ is the cost incurred to shut down the resource after receiving a Dispatch Instruction. The submitted shutdown cost must not be negative.

SBP 6.8 Format and Validation of Minimum Load Costs

For a Generating Unit, the submitted Minimum Load Cost expressed in dollars per hour ($/hr) is the cost incurred for operating the unit at minimum load. The submitted Minimum Load Cost must not be negative and must not exceed the cost-based Minimum Load Cost, as registered in the Master File for the relevant resource. For gas-fired resources, the cost-based Minimum Load Cost shall be derived pursuant to Section 5.11.6.1.2.

For Curtailable Demand, the submitted Minimum Load Cost ($/hr) is the cost incurred while operating the resource at reduced consumption after receiving a Dispatch Instruction. The submitted Minimum Load Cost must not be negative.

SBP 7 INTERFACE REQUIREMENTS

SBP 7.1 WEnet

WEnet provides the backbone on which any of three communications mechanisms will be utilized. These are:

(a) use of a web browser such as Netscape;

(b) use of File Transfer Protocol (FTP); or

(c) use of an Application Programming Interface (API).

Details of the technical aspects of each of these mechanisms, including information on how to change mechanisms and back-up procedures for individual SC failures, will be made available by the ISO to SCs on request. It is assumed that each SC has made application for and signed a Scheduling Coordinator Agreement. As such, each SC will already be familiar with and have arranged the mechanism, including security arrangements, by which it will initially communicate with the ISO.

SBP 7.2 Templates

The ISO Data Templates and Validation Rules document provides a description of the templates which will be utilized to enter data into the ISO's systems. For each of the three communications mechanisms, data entry is as follows:

Transmission Rights/Curtailment Instructions Template

(a) Contract Ref # [a single number]	(b) Ind Imp [yes/no]	(c) Contact Person [phone number] [name(s)]

Submitted By PTO: _____
Date Received By ISO: _____
Date Accepted By ISO: _____

(d) Contract Name(s)/Number(s)	(e) Path Name(s) and Location(s)			(f) Party	(g) SC ID	(h) ER/NCR	(i)(j) Types and Amounts of Transmission Service			(k) DA (hour-ending)	(l) HA (minutes)	(m) RT (yes/no)	(n) Service Period	
	Path Name(s)	POR Zone	POD Zone				Firm /1/	CF /1/	N-F				Beginning	Ending
[name/number 1]		[zone name]	[zone name]	[party 1]	[sc id 1]	[er]	[MW]	[MW]	[MW]	[1400]	[30]	[yes]	[hh/dd/mm/yy]	[hh/dd/mm/yy]
				[party 2]	[sc id 2]	[ncr]	["]	["]	["]		[n/a]	[no]	["]	["]
				[party n]	[sc id n]	[er]	["]	["]	["]		[20]	[yes]	["]	["]
[name/number 2]		[zone name]	[zone name]	[party 1]	[sc id 1]	[er]	[MW]	[MW]	[MW]	[1400]	[20]	[yes]	["]	["]
				[party 2]	[sc id 2]	[ncr]	["]	["]	["]		[n/a]	[no]	["]	["]
				[party n]	[sc id n]	[er]	["]	["]	["]		[20]	[yes]	["]	["]
[name/number n]		[zone name]	[zone name]	[party 1]	[sc id 1]	[er]	[MW]	[MW]	[MW]	[1500]	[20]	[yes]	["]	["]
				[party 2]	[sc id 2]	[ncr]	["]	["]	["]		[n/a]	[no]	["]	["]
				[party n]	[sc id n]	[er]	["]	["]	["]		[20]	[yes]	["]	["]

(o) Non-Emergency Curtailments

[If other than pro rata, attach spreadsheet for ISO to use in allocating curtailments to rights holders between the indicated Zones. Otherwise, indicate "pro rata" here.]

(p) Emergency Curtailments

[Describe special procedures/requirements here. Indicate "N/A" if none.]

/1/ Priorities for firm and conditional firm transmission service are indicated in Schedules using Adjustment Bids as described in the SP.

SCHEDULING COORDINATOR APPLICATION PROTOCOL (SCAP)

SCAP 1 OBJECTIVE, DEFINITION AND SCOPE

SCAP 1.1 Objective

The objective of the SCAP is to inform an SC Applicant of the actions it must take and information it must provide to become an approved Scheduling Coordinator (SC). The SCAP also describes the actions the ISO will take to evaluate a submitted application.

SCAP 1.2 Definitions

SCAP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix refers to a Section or an Appendix of the ISO Tariff unless otherwise indicated. References to SCAP are to this Protocol or to the stated paragraph of this Protocol.

SCAP 1.2.2 Special Terms for this Protocol

In this Protocol, the following words and expressions shall have the meaning set forth below:

"Electronic Data Interchange" (EDI) means the routine exchange of business documented on electronic media such as purchase orders, invoices and remittance. The format of the data is based on an industry-approved format such as those published by the ANSI ASC X12 committee.

"ISO Application File Template" means all information (administrative, financial and technical) pertaining to Scheduling Coordinators which must be maintained in a current form by the ISO and the Scheduling Coordinator.

"SC Customer" means a customer of the SC Applicant or a Scheduling Coordinator for whom the SC provides services relevant to the ISO Controlled Grid.

"Validation, Estimation and Editing" (VEE) applies to Meter Data directly acquired by the ISO. Validation is the process of checking the data to ensure that it is contiguous, within pre-defined limits and has not been flagged by the meter. Estimation and Editing is the process of replacing or making complete Meter Data by using data from redundant meters, schedules, PMS or, if necessary, statistical estimation.

"Value Added Network" (VAN) means a data communications service provider that provides, stores and forwards electronic data delivery services within its network and to subscribers on other VANs. The data is mostly EDI type messages.

SCAP 1.2.3 Rules of Interpretation

(a) If the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

SCAP 1.3 Scope

SCAP 1.3.1 Scope of Application to Parties

The SCAP will apply to:

(a) Scheduling Coordinator Applicants;

(b) Scheduling Coordinators; and

(c) the ISO.

SCAP 1.3.2 Liability of the ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

SCAP 2 PROCEDURE TO BECOME A SCHEDULING COORDINATOR

SCAP 2.1 SC Applicant makes a Request

To become a Scheduling Coordinator, a SC Applicant must submit a written request for an application and other necessary information to the ISO by mail, fax, e-mail or in person. Alternatively, a SC Applicant may retrieve the application and necessary information from the ISO Home Page.

SCAP 2.2 ISO Information

The ISO will provide the following information, in its most current form, on the ISO Home Page. Upon a request by a SC Applicant, the ISO will send the following information by mail:

(a) the SC Application Form (including the ISO Application File Template which is Appendix C);

(b) the ISO Tariff and ISO Protocols;

(c) pro forma Meter Service Agreements and Interim Black Start Agreement;

(d) historical ISO charges (Note: prior to January 2, 1998, estimated ISO charges) including, but not limited to, charges for purchased Ancillary Services, ISO Grid Management Charge, ISO Grid Operations Charge, Imbalance Energy market charges, and Usage Charges to assist the SC Applicant in determining the ISO Security Amount the SC Applicant must provide; and

(e) a pro forma letter of understanding for payment for SC Applicants with Approved Credit Ratings, guarantee, letter of credit and escrow agreement for the ISO Security Amount, all of which will be in a form acceptable to the ISO.

SCAP 2.3 Duplicate Information

If two or more SCs apply simultaneously to register with the ISO for a single meter or Meter Point for an ISO Metered Entity or if an SC applies to register with the ISO for a meter or Meter Point for an ISO Metered Entity for which an SC has already registered, the ISO will return the application with an explanation that only one SC may register with the ISO for the meter or Meter Point in question and that an SC has already registered or that more than one SC is attempting to register for that meter or Meter Point. The ISO will send the SC Applicant the name and address of the applicable SC or SC Applicant.

SCAP 2.4 SC Applicant returns Application

At least 60 days before the proposed commencement of service, the SC Applicant must return a completed application form with the prescribed non-refundable application fee to cover the application processing costs, site visit and the costs of furnishing the ISO Tariffs.

SCAP 2.5 Notice of Receipt

Within 3 Business Days of receiving the application, the ISO will send a written notification to the SC Applicant that it has received the application and the non-refundable fee.

SCAP 2.6 ISO Review of Application

Within 14 days after receiving an application, the ISO will notify the SC Applicant whether the SC Applicant has submitted all necessary information as set forth in ISO Tariff Sections 2.2.3 and 2.2.4, and the ISO Application File Template requirements.

SCAP 2.6.1 Information Requirements

The SC Applicant must submit with its application:

(a) the proposed date for commencement of service which may not be less than 60 days after the date the application was filed, unless waived by the ISO;

(b) financial and security information as set forth in ISO Tariff Section 2.2.3.2; and

(c) the prescribed non-refundable application fee.

SCAP 2.6.2 SC Applicant's Obligation for Contracts

An SC Applicant must certify that it is duly authorized to represent the Generators and Loads, which are its SC Customers and must further certify that:

(a) represented Generators have entered into Participating Generator Agreements with the ISO;

(b) represented UDCs have entered into UDC agreements with the ISO;

(c) represented ISO Metered Entities have entered into Meter Service Agreements with the ISO;

(d) none of the Wholesale Customers it will represent are ineligible for wholesale transmission service pursuant to the provisions of the FPA Section 212(h); and

(e) each End-Use Customer it will represent is eligible for Direct Access service pursuant to an established program approved by the California Public Utilities Commission or a Local Regulatory Authority.

SCAP 2.7 Deficient Application

In the event the application is deficient, the ISO will send a written notification of the deficiency to the SC Applicant within 14 days of receipt by the ISO of the application explaining the deficiency and requesting additional information.

SCAP 2.7.1 SC Applicant's Additional Information

Once the ISO requests additional information pursuant to Section 2.7, the SC Applicant has 7 days, or such longer period as the ISO may agree, to provide the additional material requested by the ISO.

SCAP 2.7.2 No Response from SC Applicant

If the SC Applicant does not submit additional information within 7 days or the longer period referred to in SCAP 2.7.1, the application may be rejected by the ISO in accordance with ISO Tariff Section 2.2.4.2(d).

SCAP 3 ISO APPROVAL OR REJECTION OF AN APPLICATION

SCAP 3.1 Approval or Rejection Letter

(a) If the ISO approves the application, it will send an approval letter with a signed SC Agreement for the SC Applicant's signature and any required software licensing agreement.

(b) If the ISO rejects the application, the ISO will send a rejection letter stating one or more of the following grounds:

i. incomplete information;

ii. non-compliance with security requirements;

iii. non-compliance with third party contractual obligations;

iv. non-compliance with technical requirements; or

v. non-compliance with any other SCAP or ISO Tariff requirements.

Upon request, the ISO will provide guidance as to how the SC Applicant can cure the grounds for the rejection.

SCAP 3.2 Time for Processing Application

The ISO will make a decision whether to accept or reject the application within 14 days of receipt of the application. If more information is requested, the ISO will make a final decision within 14 days of the receipt of all outstanding or additional information requested.

SCAP 4 SC APPLICANT'S RESPONSE

SCAP 4.1 SC Applicant's Acceptance

If the ISO accepts the application, the SC Applicant must return an executed SC Agreement, Meter Service Agreements, Interim Black Start Agreements and letter of credit, guarantee or escrow agreement for the ISO Security Amount, as applicable.

SCAP 4.2 SC Applicant's Rejection

SCAP 4.2.1 Resubmittal

If an application is rejected, the SC Applicant may resubmit its application at any time. An additional application fee will not be required for the second application submitted within 6 months after a rejection.

SCAP 4.2.2 Appeal

The SC Applicant may also appeal against the rejection of an application by the ISO. An appeal must be submitted within 28 days following the rejection of its application, as set forth in ISO Tariff Section 2.2.4.3 and 2.2.4.4.

SCAP 5 POST APPLICATION PROCEDURES PRIOR TO FINAL CERTIFICATION

SCAP 5.1 SC's Administrative, Financial and Technical Requirements

The ISO will not certify that an SC Applicant has become a Scheduling Coordinator until the SC Applicant has:

(a) provided the technical/operational information required to complete the ISO Application File Template, and to comply with ISO Tariff Section 10.6;

(b) executed software licensing agreement for the software used in conducting business with the ISO in a form approved by the ISO, if applicable;

(c) bought and installed any required software for functional interface in order to Validate, Estimate and Edit meter values (VEE).

(d) purchased the requisite Value Area Network (VAN) service in order to support Electronic Data Interchange (EDI) requirements;

(e) provided its bank account information and arranged for Fed-Wire System transfers as defined in SABP 1.2.2;

(f) submitted a timetable for completion of its operational facilities, in order to coordinate site visits by ISO staff to ensure compliance with the ISO Tariff Section 2.2.7.1; and

(g) bought and installed a WEnet account in order to communicate with the ISO.

SCAP 6 FINAL CERTIFICATION OF SC APPLICANT

The SC Applicant will become a Scheduling Coordinator when:

(a) its application has been accepted;

(b) it has entered into an SC Agreement, Meter Service Agreements and Interim Black Start Agreements, if applicable, with the ISO;

(c) the SC Applicant has met the financial requirements of ISO Tariff Section 2.2.3.2; and

(d) the SC Applicant has fulfilled all technical/operational requirements of ISO Tariff Section 2.2.7.1, SCAP 5.1 and the ISO Application File Template.

The ISO will not certify an SC Applicant as a Scheduling Coordinator until the SC Applicant has completed all the above referenced requirements to the ISO's satisfaction, at least 14 days before the commencement of service.

SCAP 7 SC'S ONGOING OBLIGATIONS AFTER CERTIFICATION

SCAP 7.1 Scheduling Coordinator's Obligation to Report Changes

SCAP 7.1.1 Obligation to Report a Change in Filed Information

Each SC has an ongoing obligation to inform the ISO of any changes to any of the information submitted by it to the ISO as part of the application process, including any changes to the additional information requested by the ISO. SCAP Appendix B sets forth the procedures for changing the SC's information and timing of notifying the ISO of such changes.

SCAP 7.1.2 Obligation to Report a Change in Credit Rating

The SC has an ongoing obligation to inform the ISO within 3 Business Days if its Approved Credit Rating has been reduced below the ISO requirements.

SCAP 7.1.3 Obligation to Maintain ISO Security Amount

The SC has an ongoing obligation to maintain the ISO Security Amount as set forth in ISO Tariff Section 2.2.7.3. Alternatively, the SC has the

II. SC Customer Information

2.1 The information required under Appendix C, the ISO Application File Template, must be provided for represented SC Metered Entities, which are Generators. The SC Applicant must submit all requested information prior to final certification, which must occur fourteen (14) days before the commencement of service.

2.2 Information for SC Metered Entities, which are End Users or Eligible Customers, must be kept in a standard business format based on generally accepted accounting principals. The ISO shall have the right to inspect and audit a Scheduling Coordinator's accounts and files relating to its SC Metered Entities after giving two Business Days notice in writing.

2.3 The SC Applicant must submit a list of all ISO Metered Entities, which it will represent.

III. Security Requirement

3.1 The SC Applicant has an Approved Credit Rating as set forth in the ISO Tariff: (yes/no).

The SC Applicant's credit rating is _____.

Please attach certified documentation of an Approved Credit Rating from Standard & Poor's, Moody's Investors Services or the equivalent. SC Applicant must also submit, before final certification, an executed letter of understanding for payment providing contact details in case of default. **OR**

3.2 The SC Applicant will provide an irrevocable and unconditional guarantee from a company which has an Approved Credit Rating: (yes / no).

The SC Applicant must submit a signed irrevocable and unconditional guarantee in an ISO approved form and certified documentation of the other company's Approved Credit Rating before final certification. **OR**

3.3 The SC Applicant will provide an irrevocable and unconditional letter of credit: (yes / no).

Amount: $_____.

(a) Represented Generators have signed Participating Generator Agreements: (yes / no).

(b) Represented UDCs have signed UDC Operating Agreements and Meter Service Agreements: (yes / no).

(c) Represented ISO Metered Entities have signed Meter Service Agreements: (yes / no).

(d) Wholesale Customers it will represent have warranted to the SC Applicant that they are eligible for wholesale transmission service pursuant to the provisions of the FPA Section 212(h): (yes / no).

(e) Each End-Use Customer it will represent which requests Direct Access service has warranted to the SC Applicant that the End-Use Customer is eligible for such service: (yes / no).

5.2 The SC Applicant confirms that all of the parties which it represents as SC Customers have granted it all necessary agency authority, whether actual, implied or inherent, to enable the SC to perform all of its obligations under the ISO Tariff: (yes / no).

5.3 Notwithstanding 5.2, the SC confirms that it will have the primary responsibility, as the principal, for all SC payment obligations under the ISO Tariff : (yes / no).

VI. Additional Information and Obligations

6.1 The SC Applicant agrees to provide such further information to the ISO as the ISO may deem necessary to process the application and certify the SC Applicant as a SC now and on a continuing basis.

6.2 Subject to the ISO Tariff, the SC Applicant agrees to promptly report to the ISO within seven (7) Business Days or earlier any changes regarding the information provided by it referred to in the SCAP and in the application with the exception of the security requirement data referred to in Part III of SCAP Appendix A which must be updated within three (3) Business Days. The Scheduling Coordinator shall be responsible if a failure to submit revised technical data more promptly extends the period during which schedules are rejected by the ISO.

6.3 The SC Applicant agrees to enclose herein the non-refundable application fee of $500 to cover the application processing costs, site visit and costs of providing ISO Tariff.

Please make check payable to:

The California Independent System Operator Corporation

6.4 SC Applicant agrees to promptly execute and return the SC Agreement, Meter Service Agreements, Interim Black Start Agreements, software licensing agreement, letter of understanding, letter of credit, guarantee, escrow agreement, as applicable, and Fed-Wire System bank account number, after receiving its application approval letter from the ISO.

6.5 Final certification is contingent upon SC Applicant fulfilling all financial and technical requirements as referenced in the SCAP (including Appendix C, the ISO Application File Template).

SCAP APPENDIX B

Procedures for Changes or Additions to

Scheduling Coordinator's (SC's) Information

The SC must update, amend and / or correct the information originally submitted to the ISO during the SC application process using the format set forth in this Appendix and / or a revised Appendix C, the ISO Application File Template. The SC must submit all changes or additional information by first class postage paid mail to:

California Independent System Operator Corporation

c/o SC Application Processing Office

151 Blue Ravine Road

Folsom, CA 95630

The SC must notify the ISO of any change to the information that it has previously submitted to the ISO, or any additional information, at least three Business Days before the change will take effect.

The ISO will send a written acknowledgment of receipt of the SC's changes within three Business Days of receipt. The receipt shall be sent to the address on file with the ISO or the address specified in the notice of change received by the ISO.

Prior Information

_____

_____

_____

New Information

_____

_____

_____

Explanation and Reason for Change

_____

_____

_____

SCHEDULING PROTOCOL

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SCHEDULING PROTOCOL (SP)

SP 1 OBJECTIVES, DEFINITIONS AND SCOPE

SP 1.1 Objectives

The objectives of this Protocol are:

(a) to process the scheduling input data (submitted to the ISO under the Ancillary Service Requirements Protocol (ASRP), the Demand Forecasting Protocol (DFP), and the Schedules and Bids Protocol (SBP)) in order to develop Final Schedules for the Day-Ahead and Hour-Ahead Markets (real-time management of the ISO Controlled Grid is addressed in the Dispatch Protocol (DP));

(b) to provide for the scheduling of the use of Firm Transmission Rights and use of transmission service rights under Existing Contracts;

(c) to assist the ISO in purchasing Ancillary Services; and

(d) to manage Congestion.

SP 1.2 Definitions

SP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is to a Section or an Appendix of the ISO Tariff. References to SP are to this Protocol or to the stated paragraph of this Protocol.

SP 1.2.2 [Not used]

SP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(iii) problems with data or the processing of data cause a delay in receiving or issuing Schedules or publishing information on the WEnet;

(iv) problems with telecommunications or computing infrastructure cause a delay in receiving or issuing Schedules or publishing information on the WEnet; or

(v) such waiver or variation of timing requirements is reasonably necessary to preserve System Reliability, prevent an imminent or threatened System Emergency or to retain Operational Control over the ISO Controlled Grid during an actual System Emergency.

(b) If the ISO temporarily implements a waiver or variation of such timing requirements (including the omission of any step) consistent with Section 2.2.12.1 of the ISO Tariff and SP 3(a), the ISO will publish the following information on WEnet as soon as practicable:

(i) the exact timing requirements affected;

(ii) details of any substituted timing requirements;

(iii) an estimate of the period for which this waiver or variation will apply; and

(iv) reasons for the temporary waiver or variation.

(c) If, despite the variation of any time requirement or the omission of any step, the ISO either fails to receive sufficient Schedules to operate the Day-Ahead Market or is unable to perform Congestion Management in the Day-Ahead Market, the ISO may abort the Day-Ahead Market and require all Schedules to be submitted, and Congestion Management to be performed, in the Hour-Ahead Market.

(d) If, despite the variation of any time requirement or omission of any step, the ISO either fails to receive sufficient Schedules to operate the Hour-Ahead Market or is unable to perform Congestion Management in the Hour-Ahead Market, the ISO may abort the Hour-Ahead Market and function in real time.

(e) The incorporation of the scheduling of the use of rights under Existing Contracts into the ISO's Day-Ahead, Hour-Ahead and real-time processes is additionally described in SP 7 and in the SBP.

SP 3.1 Balanced Schedules

SP 3.1.1 Types of Balanced Schedules

A Schedule shall be treated as a Balanced Schedule when the SC's aggregate Generation and external imports (adjusted for Transmission Losses) and Inter-Scheduling Coordinator Energy Trades (whether

purchases or sales), equal the SC's aggregate Demand Forecast, including external exports, with respect to all entities for which the SC schedules. On an interim basis, the ISO may assist SCs in matching Inter-Scheduling Coordinator Energy Trades.

SP 3.1.2 Preferred Schedules

The Preferred Schedule is the initial Schedule submitted by a SC in the Day-Ahead Market or Hour-Ahead Market. A Preferred Schedule shall be a Balanced Schedule submitted to the ISO by each SC on a daily and/or hourly basis.

SP 3.1.3 Seven-Day Advance Schedules

SCs may submit Balanced Schedules for up to seven (7) Trading Days at a time, representing the SC's Preferred Schedule for each Day-Ahead Market and/or Hour-Ahead Market. These advance Schedules can be overwritten by new Preferred Schedules at any time prior to the deadline for submitting Day-Ahead Schedules and Hour-Ahead Schedules, as described in the SP. If not overwritten by the SC, a Schedule submitted in advance of this deadline for submission will become the SC's Preferred Schedule at the deadline for submitting Day-Ahead Schedules and/or Hour-Ahead Schedules. There is no validation of Schedules submitted in advance of the deadline for submitting Preferred Schedules. As part of the scheduling and validation process, the ISO will calculate and publish, via WEnet, the GMMs applicable to the Day-Ahead and Hour-Ahead Markets eight (8) days ahead of the Trading Day to which they relate, as described in SP 4.

SP 3.1.4 Suggested Adjusted Schedules

If the sum of SCs' Preferred Schedules would cause Congestion across any Inter-Zonal Interface, the ISO shall issue Suggested Adjusted Schedules to all SCs in the Day-Ahead Market only. These Suggested Adjusted Schedules will not apply to uses of transmission owned by Non-Participating TOs nor to uses of Existing Rights. A modification flag, set by the ISO, will indicate whether the scheduled output in a Settlement Period has been modified as a result of Congestion Management. The ISO will publish as public information, via the WEnet, estimated Usage Charges for Energy transfers between Zones.

SP 3.1.5 Revised Schedules

Following receipt of a Suggested Adjusted Schedule, a SC may submit to the ISO a Revised Schedule, which shall be a Balanced Schedule, and which shall seek to reduce or eliminate Congestion. There are no Revised Schedules in the Hour-Ahead Market.

SP 3.1.6 Final Schedules

If the ISO notifies a SC that there will be no Congestion on the ISO Controlled Grid based on the Preferred Schedules submitted by all

SP 3.2.1.1 By 5:00 am, One Day Ahead

By no later than 5:00 am on the day before the Trading Day, the ISO will notify SCs of the Energy Requirements from any Reliability Must-Run Units which the ISO requires to run in the Trading Day, except in those instances where a Reliability Must-Run Unit requires more than one day's notice, in which case the ISO may notify the applicable SC more than one day in advance of the Trading Day;

SP 3.2.1.2 By 6:00 am, One Day Ahead

By no later than 6:00 am on the day before the Trading Day, SCs that have been notified that a Reliability Must-Run Unit is required to run in the Trading Day will inform the ISO, with regard to each hour for which the ISO has provided such notice, whether the RMR Owner will take payment from the market or under the RMR Contract.

SP 3.2.2 By 6:00 am, One Day Ahead

By 6:00 am on the day ahead of the Trading Day (for example, by 6:00 am on Tuesday for the Wednesday Trading Day), the following information flows for each Settlement Period of the Trading Day will be required to take place:

(a) SCs will provide, via WEnet, the ISO with forecasts of their Direct Access Demand by UDC Service Area ;

(b) the ISO will publish, via WEnet, an updated forecast of system Demands and of the Ancillary Services requirements; and

(c) the ISO will validate (in accordance with the SBP) the information submitted above by SCs and UDCs.

SP 3.2.3 By 6:30 am, One Day Ahead

By 6:30 am on the day ahead of the Trading Day (for example, by 6:30 am on Tuesday for the Wednesday Trading Day) and for each Settlement Period of the Trading Day: the ISO will provide to UDCs, via WEnet, the sum of the SCs' Direct Access Demand Forecasts by UDC Service Area; and

SP 3.2.4 By 8:00 am, One Day Ahead

By 8:00 am on the day ahead of the Trading Day (for example, by 8:00 am on Tuesday for the Wednesday Trading Day), and for each Settlement Period of that Trading Day, Firm Transmission Rights owners will notify the ISO, via the Secondary Registration System or other means established by the ISO, of any transaction of Firm Transmission Rights and of any changes in SCs' rights to schedule the use of Firm Transmission Rights at particular Inter-Zonal Interfaces.

Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which were part of their Preferred Day-Ahead Schedules;

(g) the ISO will validate (in accordance with the SBP) all contract usage templates received from SCs for scheduled uses of Existing Contract rights and Firm Transmission Rights;

(h) the ISO will validate that all SC submitted Preferred Day-Ahead Schedules are compatible with the RMR requirements of which SCs were notified for that Trading Day and with the SCs' elected options for delivering the required Energy;

(i) the ISO will start the first iteration of Inter-Zonal Congestion Management process as described in SP 10; and

(j) the ISO will start the Ancillary Services bid evaluation process as described in SP 9;

SP 3.2.6.2 Pre-validation

At 10 minutes prior to the deadline for submittal of the Preferred Day-Ahead Schedules, Adjustment Bids, schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids (the "submittal"), the ISO shall conduct a pre-validation of the stage two validation described in the SBP. The purpose of this is to allow the SCs, particularly those involved in the Inter-Scheduling Coordinator Energy Trades, to identify and resolve any validation problems. The ISO will immediately communicate the results of each SC's pre-validation to that SC via WEnet.

SP 3.2.6.3 Invalidation

Except with respect to invalidated contract usage associated with Existing Contract rights or Firm Transmission Rights, invalidation of the submittal for any Settlement Period results in rejection of the submittal for that Settlement Period. SCs will be notified of any invalid contract usage via an invalidated contract usage template issued, via the WEnet, by the ISO. Invalidation of contract usage will not cause the rejection of the SC's submittal; instead, invalid contract usage will be treated as new firm uses of ISO transmission service without the priorities and protections afforded the scheduled use of Existing Contract rights and Firm Transmission Rights. During the initial operations of the ISO, the ISO may assist SCs to resolve mismatches in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades contained in their Preferred Schedules in accordance with SP 3.2.6.4. Except with respect to contract usage templates (for which SCs can check whether or not their submittal will pass the ISO's validation checks between 9:00 am and 10:00 am), SCs may check at any time prior to 10:00 am whether or not their submittal will pass the ISO's validation checks at 10:00 am. It is the responsibility of the SCs to perform such checks since Preferred

Day-Ahead Schedules, Adjustment Bids, Schedules of self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which are invalidated cannot be resubmitted after 10:00 am for the Day-Ahead Market, except that, during the initial period of ISO operations, the ISO will allow resubmission of Preferred Schedules which have mismatches in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades. The ISO will immediately communicate the results of each SC's 10:00 am validation to that SC via WEnet. If the usage or sum of the usages associated with an Existing Contract results in the contract being over-scheduled, the usages will be adjusted such that a usage in excess of the Existing Contract rights will be considered a new firm use (NFU) and will be exposed to Congestion charges.

SP 3.2.6.4 Inter-Scheduling Coordinator Energy Trades - Mismatches

During the initial period of ISO operations, if the ISO detects a mismatch in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades, the ISO will promptly notify both the receiving and sending SCs that a mismatch exists and will specify the time, which will allow them approximately one half-hour, by which they may submit modified Schedules which resolve the mismatch. If the SCs are unable to resolve the mismatch as to quantities in the allotted time and provided there is no dispute as to whether the trade occurred or over its location, then the ISO may adjust the SCs' Schedules in accordance with the following procedure:

(a) The ISO will determine which Schedule contains the higher scheduled quantity of Energy for the Inter-Scheduling Coordinator Energy Trade and will reduce it so that it is equal to the lower scheduled quantity. However, if the Schedule specifying the higher scheduled quantity of Energy contains only Inter-Scheduling Coordinator Energy Trades, the ISO will increase the Schedule specifying the lower quantity of Energy so that it is equal to the higher scheduled quantity of Energy.

(b) If there is a dispute between the SCs as to whether the trade occurred or over its location, the ISO will remove the disputed trade from the Schedules in which it appears.

(c) As a consequence of the adjustments under (a) or (b) above, the SCs whose Schedules have been adjusted will no longer have a Balanced Schedule. The ISO will adjust their resources based on the following priority: Demands, exports, imports, Generation, and other Inter-Scheduling Coordinator Energy Trades.

(d) The adjustments to each SC's portfolio will be based on the Adjustment Bids provided by the SC.

(e) The ISO will notify each SC whose Schedule has been adjusted as to the adjustment in its Schedule.

communicate the results of the pre-validation of each SC's submittal to that SC via WEnet.

SP 3.2.8.3 Invalidation

Except with respect to invalidated contract usage associated with Existing Contract rights or Firm Transmission Rights, invalidation of the submittal for any Settlement Period results in rejection of the submittal for that Settlement Period. SCs will be notified of any invalid contract usage via an invalidated contract usage template issued, via the WEnet, by the ISO. Invalidation of contract usage will not cause the rejection of the SC's submittal; instead, invalid contract usage will be treated as new firm uses of ISO transmission service without the priorities and protections afforded the scheduled use of Existing Contract rights and Firm Transmission Rights. During the initial operations of the ISO, the ISO may assist SCs to resolve mismatches in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades in accordance with 3.2.8.4. Except with respect to contract usage templates, SCs may check at any time prior to 12:00 noon whether or not their submittal will pass the ISO's validation checks (which are undertaken at 12:00 noon). It is the responsibility of the SCs to perform such checks since Revised Day-Ahead Schedules, Adjustment Bids, schedules of self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which are invalidated cannot be resubmitted after 12:00 noon for the Day-Ahead Market, except that during the initial period of operations, the ISO will allow resubmission of Schedules to resolve mismatches in the scheduled quantities and locations for Inter-Scheduling Coordinator Energy Trades. The ISO will immediately communicate the results of each SC's 12:00 noon validation to that SC via WEnet. If the usage or sum of the usages associated with an Existing Contract results in the contract being over-scheduled, the usages will be adjusted such that a usage in excess of the Existing Contract rights will be considered a new firm use (NFU) and will be exposed to Congestion charges.

SP 3.2.8.4 Inter-Scheduling Coordinator Energy Trades - Mismatches

During the initial period of ISO operations, if the ISO detects a mismatch in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades, the ISO will promptly notify both the receiving and sending SCs that a mismatch exists and will specify the time, which will allow them approximately one half-hour, by which they may submit modified Schedules which resolve the mismatch. If the SCs are unable to resolve the mismatch as to quantities in the allotted time and provided there is no dispute as to whether the trade occurred or over its location, the ISO may adjust the SCs' Schedules in accordance with the following procedure:

(a) The ISO will determine which Schedule contains the higher scheduled quantity of Energy for the Inter-Scheduling

(c) the ISO will publish on WEnet the Day-Ahead Usage Charge rate (in $/MWh of scheduled flow) for Energy transfer between Zones, if any;

(d) the ISO will provide, via WEnet, as part of the Final Day-Ahead Schedules, schedules for Ancillary Services to the SCs which either:

(i) submitted Ancillary Services bids and which, as a result, have been selected to supply Ancillary Services; or

(ii) submitted schedules to self-provide Ancillary Services and which schedules have been validated by the ISO; and

(iii) specified Inter-Scheduling Coordinator Ancillary Service Trades which have been validated by the ISO; and

(e) the ISO will coordinate with adjacent Control Areas on the net schedules between the ISO Control Area and such other Control Areas. If the ISO and the operator of an adjacent Control Area have different records with respect to the net schedules, individual SC intertie schedules will be examined. If the other Control Area's records are determined to be correct, the ISO will notify the affected SC. If the other Control Area Operator's records are in error, no changes will be required by the ISO or affected SCs. The affected SC is required to correct its schedule in the Hour-Ahead Market.

SP 3.2.10 By 1:30 pm, Day Ahead

By 1:30 pm on the day ahead of the Trading Day (for example, by 1:30 pm on Tuesday for the Wednesday Trading Day) and for each Settlement Period of the Trading Day the ISO will publish, via WEnet, an updated forecast of system Demands.

SP 3.2.11 Between 1:00 p.m. and 10:00 p.m.

If, at any time after 1:00 p.m. and before 10:00 p.m. of the day prior to the Trading Day, the ISO determines that it requires Ancillary Services in addition to those provided through the Final Day-Ahead Schedules issued under SP 3.2.9, it may procure such additional Ancillary Services by providing to SCs, via WEnet, amended schedules for Ancillary Services that had been bid in the Day-Ahead Market but were not previously selected in the Final Day-Ahead Schedules, and have not been previously withdrawn. The ISO shall select such Ancillary Services in price merit order (and in the relevant Zone if the ISO is procuring Ancillary Services on a Zonal basis). Such amended schedules shall be provided to the SCs no later than 10:00 p.m. of the day prior to the Trading Day.

(c) SCs will submit their Ancillary Services bids, if any, to the ISO in accordance with the SBP and SP 9;

(d) SCs will submit their Schedules for self-provided Ancillary Services and Inter-Scheduling Coordinator Ancillary Service Trades, if any, to the ISO in accordance with the SBP and SP 9;

(e) the ISO will validate (in accordance with the SBP) all SC submitted Preferred Hour-Ahead Schedules for Energy and Adjustment Bids;

(f) SCs will submit contract usage templates for scheduled uses of Existing Contract rights and Firm Transmission Rights in accordance with the Hour-Ahead Market schedule, including usage template changes needed in response to line derations;

(g) the ISO will validate (in accordance with the SBP) all contract usage templates received from SCs for scheduled uses of Existing Contract rights and Firm Transmission Rights;

(h) the ISO will validate (in accordance with the SBP) all SC submitted Schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which were part of their Preferred Hour-Ahead Schedules;

(i) the ISO will start the Inter-Zonal Congestion Management process as described in SP 10;

(j) the ISO will start the Ancillary Services bid evaluation process as described in SP 9; and

(k) the ISO will validate that all SC submitted Preferred Hour-Ahead Schedules are compatible with the RMR requirements of which SCs were notified for that Trading Day and with the SCs' elected options for delivering the required Energy.

SP 3.3.1.2 Pre-validation

At 10 minutes prior to the deadline for submittal of the Preferred Hour-Ahead Schedules, Adjustment Bids, schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids (the "submittal"), the ISO shall conduct a pre-validation of the stage two validation described in the SBP. The purpose of this is to allow the SCs, particularly those involved in the Inter-Scheduling Coordinator Energy Trades, to identify and resolve any validation problems. The ISO will immediately communicate the results of the pre-validation of each SC's submittal to that SC via WEnet.

SP 3.3.1.3 Invalidation

Except with respect to invalidated contract usage associated with Existing Contract rights or Firm Transmission Rights, invalidation of the

submittal results in rejection of the submittal. SCs will be notified of any invalid contract usage via an invalidated contract usage template issued, via the WEnet, by the ISO. Invalidation of contract usage will not cause the rejection of the SC's submittal; instead, invalid contract usage will be treated as new firm uses of ISO transmission service without the priorities and protections afforded the scheduled use of Existing Contract rights and Firm Transmission Rights. SCs may check at any time prior to two hours and fifteen minutes ahead of the relevant Settlement Period whether or not their submittals will pass the ISO's validation checks (which are undertaken at two hours and fifteen minutes ahead of the Settlement Period). It is the responsibility of SCs to perform such checks since Preferred Hour-Ahead Schedules, Adjustment Bids, schedules of self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades and Ancillary Services bids which are invalidated cannot be resubmitted for the Hour-Ahead Market after two hours and fifteen minutes ahead of the relevant Settlement Period. The ISO will immediately communicate the results of each SC's two hour and fifteen minute ahead validation to that SC via WEnet. If the usage or sum of the usages associated with an Existing Contract results in the contract being over-scheduled, the usages will be adjusted such that a usage in excess of the Existing Contract rights will be considered a new firm use (NFU) and will be exposed to Congestion charges.

SP 3.3.2 **By One Hour Ahead**

By one hour ahead of the Settlement Period (for example, by 11:00 am for the Settlement Period starting at 12:00 noon [or hour ending 1300]) and in respect of that Settlement Period:

(a) The ISO will use the SC's Final Day-Ahead Schedule, without any Day-Ahead Adjustment Bids or Day-Ahead Ancillary Service bids, in the event the SC's Preferred Hour-Ahead Schedule fails validation. If a SC desires to submit an Hour-Ahead Schedule that is different than its Final Day-Ahead Schedule the SC must submit the Hour-Ahead Schedule including the addition or removal of any resources (i.e., for those resources to be removed, a zero value for the hourly MW quantity) in its Final Day-Ahead Schedule that are to be added, or that are not to be included, in the Hour-Ahead Schedule. A SC's failure to add or remove such resources will cause the Hour-Ahead Schedule to be unbalanced, and rejected as such in the ISO's validation process.

(b) the ISO will complete, if necessary, the Inter-Zonal Congestion Management process described in SP 10;

(c) the ISO will provide, via WEnet, Final Hour-Ahead Schedules for Energy to the ISO's real-time dispatchers for use under the DP and to all SCs which, depending on the existence of Inter-Zonal Congestion, could be:

(i) the Preferred Hour-Ahead Schedules (when no Congestion was found at one hour ahead); or

(ii) modified Preferred Hour-Ahead Schedules for those SCs which had their Preferred Hour-Ahead Schedules for Energy modified for Inter-Zonal Congestion; and

(d) the ISO will publish on WEnet the Hour-Ahead Usage Charge rate (in $/MWh of scheduled flow) for Energy transfers between Zones, if any;

(e) the ISO will provide, via WEnet, as part of the Final Hour-Ahead Schedules, schedules for Ancillary Services to the ISO's real-time dispatchers for use under the DP and to the SCs which either:

(i) submitted Ancillary Services bids and which, as a result, have been selected to supply Ancillary Services; or

(ii) specified Inter-Scheduling Coordinator Ancillary Service Trades, or submitted schedules to self-provide Ancillary Services and which schedules have been validated by the ISO; and

(f) each SC will provide the ISO, via a form and by means of communication specified by the ISO, resource specific information for all Generating Units and Curtailable Demands constituting its System Unit, if any, scheduled or bid into the ISO's Day-Ahead Market and/or Hour-Ahead Market for Ancillary Services.

(g) the ISO will coordinate with adjacent Control Areas on the net schedules between the ISO Control Area and such other Control Areas. If the ISO and the operator of an adjacent Control Area have different records with respect to the net schedules, individual SC intertie schedules will be examined. If the other Control Area operator's records were in error, no changes will be required by the ISO or SCs. If the other Control Area operator's records are determined to be correct, the ISO will notify the affected SC. The ISO will manually adjust the affected SC's schedule to conform with the other Control Area operator's net schedule, in real time, and the affected SC will be responsible for managing any resulting Energy imbalance.

SP 4 TRANSMISSION SYSTEM LOSS MANAGEMENT

SP 4.1 Overview

(a) A SC must ensure that each Schedule it submits to the ISO is a Balanced Schedule in which aggregate Generation and external imports (adjusted for Transmission Losses) and Inter-Scheduling Coordinator Energy Trades equals the aggregate Forecast Demand and external exports. The ISO will, for this purpose, specify GMMs for each Energy supply source

(Generating Units and external imports at Scheduling Points) to account for the Energy lost in transmitting power from Generating Units and/or Scheduling Points to Load. Inter-Scheduling Coordinator Energy Trades will not be subject to such adjustments, beyond the impact of GMMs on the respective SC's Generation and external imports. The ISO will, in accordance with this SP 4, derive a location specific GMM for each Generating Unit and external import on the ISO Controlled Grid.

(b) At all times, the ISO will make available GMMs for the seven Trading Days starting with the Trading Day after the next Trading Day. Each day, at 6:00 pm, the ISO will calculate and publish, via WEnet, the GMMs applicable to the Day-Ahead Markets and the Hour-Ahead Markets for the eighth (8^{th}) Trading Day forward. In other words, if the current Trading Day is day 0, the ISO will publish at 6:00 pm today, via WEnet, the GMMs for Trading Days 2 through 8. On Trading Day 1, at 6:00 pm, the ISO will drop the GMMs for Trading Day 1 and add the newly calculated GMMs for Trading Day 9, with the GMMs for Trading Days 3 through 8 remaining the same.

SP 4.2 Generator Meter Multipliers (GMMs)

SP 4.2.1 Derivation of GMMs

(a) The ISO will utilize the Power Flow Model to determine the GMMs which will be used to allocate, to each Generating Unit and external import, scheduled and Ex Post Transmission Losses.

(b) For each Settlement Period, the GMMs will be first calculated before SCs submit Day-Ahead Preferred Schedules. Prior to the time when SCs are required to submit their Day-Ahead Preferred Schedules, the ISO will forecast the total Control Area Demand. This forecast, along with the ISO forecast of Generation and Demand patterns throughout the ISO Control Area, will be used to develop estimated GMMs for each Generating Unit and each external import. The ISO will calculate and publish (in accordance with SP 3.2.1) GMMs for each Settlement Period to reflect different expected Generation and Demand patterns and expected operations and maintenance requirements, such as line Outages, which could affect Transmission Loss determination and allocation.

(c) The ISO will utilize the real-time Power Flow Model to calculate Ex Post GMMs to allocate Ex Post Transmission Losses to each Generating Unit and each external import. This run of the Power Flow Model will use metered Generation and Demand. Any difference between scheduled and Ex Post Transmission Losses will be considered as an Imbalance Energy deviation and will be purchased or sold in the Real Time Market at the Settlement Interval Ex Post Price.

SP 5.1.2 **Annual Reliability Must-Run Forecast - Technical Studies**

The ISO will perform off-line technical studies, adopt existing procedures developed by PTOs and/or develop new operating procedures to identify the Reliability Must-Run requirements for various levels of system Demand.

SP 5.2 **Designation of Generating Unit as Reliability Must-Run**

The ISO will have the right at any time based upon ISO Controlled Grid technical analyses and studies to designate or disqualify a Generating Unit as a Reliability Must-Run Unit.

SP 5.3 **Scheduling of Reliability Must-Run Generation**

The ISO will notify SCs of any Reliability Must-Run Units which the ISO requires to run during a Trading Day no later than 5:00 am on the day before that Trading Day, as described in SP 3.2.1.1.

SP 5.4 **[UNUSED]**

SP 6 **[UNUSED]**

SP 7 **MANAGEMENT OF EXISTING CONTRACTS FOR TRANSMISSION SERVICE**

SP 7.1 **Obligations of Participating Transmission Owners and Scheduling Coordinators**

SP 7.1.1 **Participating Transmission Owners**

Prior to the ISO accepting Schedules which include the use of Existing Rights, the Responsible PTO (as defined in the SBP) must have provided the ISO with the information required in the Transmission Control Agreement and the SBP, including transmission rights/curtailment instructions ("instructions") supplied in a form and by means of communication specified by the ISO.

SP 7.1.2 **Scheduling Coordinators**

The ISO will accept valid Schedules from a Responsible PTO that is the SC for the Existing Contract rights holders, or from Existing Contract rights holders that are SCs, or that are represented by a SC other than the Responsible PTO. Schedules submitted by SCs to the ISO which include the use of Existing Rights must be submitted in accordance with the SBP and this SP.

SP 7.2 **Allocation of Forecasted Total Transfer Capabilities**

SP 7.2.1 ***Categories of Transmission Capacity***

As used in this SP, references to new firm uses shall mean any use of ISO transmission service, except for uses associated with Existing Rights. Prior to the start of the Day-Ahead scheduling process, for each Inter-Zonal Interface, the ISO will allocate the forecasted total transfer capability of the Interface to four categories. This allocation

(c) if Congestion still exists after curtailing all lower priority schedules (e.g. representing non-firm and conditional firm uses of transmission service under Existing Contracts), the remaining transmission capacity (the subject of firm Existing Rights) is priced based upon Adjustment Bids. To the extent there are insufficient Adjustment Bids to fully mitigate the remaining Congestion, the default Usage Charge will apply and the ISO will curtail ISO transmission service (in other words, new firm uses including new firm uses of Firm Transmission Rights), pro rata, to the extent necessary; and

(d) if Congestion still exists after curtailing ISO new firm uses, scheduled uses of firm Existing Rights will be curtailed (based upon the priorities expressed in the contract usage template associated with the Schedules as described in SP 7.2.2 (a)) to the extent necessary.

SP 7.5 The ISO's Real-Time Process

Consistent with SP 7.4.4, the ISO will honor those scheduling flexibilities that may be exercised by holders of Existing Rights through their respective SCs during the ISO's real-time processes to the extent that such flexibilities do not interfere with or jeopardize the safe and reliable operation of the ISO Controlled Grid or Control Area operations. The real-time processes described in SP 7.5.1 and SP 7.5.2 will occur during the three hours following the ISO's receipt of Preferred Hour-Ahead Schedules (that is, from two hours ahead of the start of the Settlement Period through the end of such Settlement Period).

SP 7.5.1 Inter-Control Area Changes to Schedules that Rely on Existing Rights

Changes to Schedules that occur during the ISO's real-time processes that involve changes to ISO Control Area imports or exports with other Control Areas (that is, inter-Control Area changes to Schedules) will be allowed and will be recorded by the ISO based upon notification received from the SC representing the holder of the Existing Rights. The ISO must be notified of any such changes to external import/export schedules. The ISO will receive notification of real-time changes to external import/export schedules, by telephone, from the SC representing the holder of the Existing Rights. The timing and content of any such notification must be consistent with the instructions previously submitted to the ISO by the Responsible PTO in accordance with the SBP. The ISO will manually adjust the SC's schedule to conform with the other Control Area's net schedule in real time, and the notifying SC will be responsible for and manage any resulting Energy imbalance. These Imbalance Energy deviations will be priced and accounted to the SC representing the holder of Existing Rights in accordance with the SABP.

SP 7.5.2 Intra-Control Area Changes to Schedules that Rely on Existing Rights

Changes to Schedules that occur during the ISO's real-time processes that do not involve changes to ISO Control Area imports or exports with other Control Areas (that is, intra-Control Area changes to Schedules) will be allowed and will give rise to Imbalance Energy deviations. These Imbalance Energy deviations will be priced and accounted to the SC representing the holder of Existing Rights in accordance with the SABP.

SP 8 OVERGENERATION MANAGEMENT

SP 8.1 Real-Time Overgeneration Management

Overgeneration management in real time will be conducted in accordance with the DP.

SP 9 DAY/HOUR-AHEAD ANCILLARY SERVICES MANAGEMENT

SP 9.1 Bid Evaluation and Scheduling Principles

The ISO will evaluate Ancillary Services bids based on the following principles:

(a) the ISO will not differentiate between bidders other than through reserve (Regulation and Operating Reserves) price and capability to provide the reserve service, and the required locational mix of services;

(b) to minimize the costs to users of the ISO Controlled Grid, the ISO will select the bidders with lowest bids for reserve which meet its technical requirements, including location and operating capability;

(c) the ISO will (to the extent available) procure sufficient Ancillary Services to meet its technical requirements as defined in the ASRP;

(d) the ISO will evaluate and price only those Ancillary Services bids received in accordance with the SBP;

(e) the ISO will require SCs to honor their Day-Ahead Ancillary Services schedules and/or bids when submitting their Hour-Ahead Ancillary Services schedules and/or bids. A Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace such capacity to the extent scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or to the extent the Ancillary Service associated with a Generating Unit, Curtailable Demand, or System Resource successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead Market, for any reason (other than

capacity accepted in the Regulation market that represents the downward range of movement accepted by the ISO will not be deducted from the resource capacity bid into other reserve markets.

SP 9.3 Scheduling Ancillary Services Resources

(a) SCs are allowed to self-provide all or a portion of the following Ancillary Services to satisfy their obligations to the ISO:

(i) Regulation;

(ii) Spinning Reserve;

(iii) Non-Spinning Reserve; and

(iv) Replacement Reserve.

(b) The ISO will reduce the quantity of Ancillary Services it competitively procures by the corresponding amount of the Ancillary Services that SCs self-provide.

(c) The ISO shall prepare supplier schedules for Ancillary Services (both self-provided and purchased by the ISO) for the Day-Ahead Market and the Hour-Ahead Market.

(d) The Ancillary Services schedules shall contain the information set out in the SBP for each Settlement Period of the following Trading Day in the case of the Day-Ahead Schedules or for a specific Settlement Period in the case of Hour-Ahead Schedules.

(e) Once the ISO has given SCs notice of the Day-Ahead and Hour-Ahead Schedules, these schedules represent binding commitments made in the reserve markets between the ISO and the SCs concerned. A Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace such capacity to the extent scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or to the extent the Ancillary Service associated with a Generating Unit, Curtailable Demand, or System Resource successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduling Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replacement shall be at the Market Clearing Price in the Hour-Ahead Market for the Ancillary Service for the Settlement Period concerned for the Zone in which the Generating Unit or other resources on behalf of which the Scheduling Coordinator buys back the capacity, are located. The ISO will purchase the Ancillary Service concerned from another Scheduling

SP 9.5 Regulation Bid Evaluation and Pricing

SP 9.5.1 Regulation Bid Evaluation

(a) Based on the quantity and location of the system requirements, the ISO will select Generating Units, System Units, and System Resources with the Regulation bids which minimize the sum of the total Regulation bids of the Generating Units, System Units, and System Resources selected subject to two constraints:

(i) the sum of the selected amounts of Regulation bid must be greater than or equal to the required amount of Regulation; and

(ii) the amount of Regulation bid for each Generating Unit, System Unit, or System Resource must be less than or equal to that Generating Unit's, System Unit's, or System Resource's ramp rate times $Period_{minutes}$ where $Period_{minute}$ is established by the ISO, by giving Scheduling Coordinators twenty-four (24) hours advance notice, within a range from a minimum of 10 minutes to a maximum of 30 minutes.

(b) The total Regulation bid for each Generating Unit, System Unit, or System Resource is calculated by multiplying the reserve reservation bid price by the amount of Regulation bid. Subject to any locational requirements, the ISO will accept winning Regulation bids in accordance with the following criteria:

$$Min \sum_{i,j} TotalBid_{ijt}$$

subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

and

$$Cap_{ijt} \leq Cap_{ijt} \max$$

where:

$TotalBid_{ijt}$ = $Cap_{ijt} * CapRes_{ijt}$

Requirement = *Amount of upward and downward movement (Regulation) required by the ISO.*

SP 9.5.2 Regulation Price Determination

The price payable to SCs for Regulation made available for upward and downward movement in accordance with the ISO's Ancillary Services schedules will, for each Generating Unit, System Unit, and System Resource concerned, be the Zonal Market Clearing Price for Regulation calculated as follows:

$Pagc_{ijt} = MCP_{xt}$

where:

the Zonal Market Clearing Price (MCP_{xt}) for Regulation is the highest priced winning reservation bid of a Generating Unit, System Unit, or System Resource serving Demand in Zone X based on the reservation bid price (i.e., $MCP_{xt} = Max\ (CapRes_{ijt})$ in Zone X for Settlement Period t). In the absence of Inter-Zonal Congestion, the Zonal Market Clearing Prices will be equal.

SP 9.6 Spinning Reserves Bid Evaluation and Pricing

SP 9.6.1 Spinning Reserves Bid Evaluation

(a) Based on the quantity and location of the system requirements, the ISO will select the Generating Units, System Units and external imports of System Resources with the Spinning Reserve bids which minimize the sum of the total Spinning Reserve bids of the Generating Units, System Units and external imports of System Resources selected subject to two constraints:

(i) the sum of the selected amounts of Spinning Reserve bid must be greater than or equal to the required amount of Spinning Reserve; and

(ii) the amount of Spinning Reserve bid for each Generating Unit, System Unit or external import of a System Resource must be less than or equal to that Generating Unit's, System Unit's ramp rate times 10 minutes.

(b) The total Spinning Reserve bid for each Generating Unit, System Unit or external import of a System Resource is calculated by multiplying the reserve reservation bid price by the amount of Spinning Reserve bid. Subject to any locational requirements, the ISO will select the winning Spinning Reserve bids in accordance with the following criteria:

$$Min \sum_{i,j} Totalbid_{ijt}$$

subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

and

$$Cap_{ijt} \leq Cap_{ijt}max$$

where:

$TotalBid_{ijt}$ = $Cap_{ijt} * CapRes_{ijt}$

$Requirement$ = *Amount of Spinning Reserve required by the ISO.*

SP 9.6.2 Spinning Reserves Price Determination

The price payable to SCs for Spinning Reserve made available in accordance with the ISO's Ancillary Services schedules shall, for each Generating Unit, System Unit or external import of a System Resource concerned, be the Zonal Market Clearing Price for Spinning Reserve calculated as follows:

$Psp_{ijt} = MCP_{xt}$

where:

the Zonal Market Clearing Price (MCP_{xt}) for Spinning Reserve is the highest priced winning reservation bid of a Generating Unit, System Unit or external import of a System Resource serving Demand in Zone X based on the reservation bid price (i.e., $MCP_{xt} = Max(CapRes_{ijt})$ in Zone *X* for Settlement Period t). In the absence of Inter-Zonal Congestion, the Zonal Market Clearing Prices will be equal.

SP 9.7 Non-Spinning Reserves Bid Evaluation and Pricing

SP 9.7.1 Non-Spinning Reserves Bid Evaluation

(a) Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units, Curtailable Demands and external imports of System Resources with the Non-Spinning Reserve bids which minimize the sum of the total Non-Spinning Reserve bids of the Generating Units, System Units, Curtailable Demands and external imports of System Resources selected subject to two constraints:

(i) the sum of the selected amounts of Non-Spinning Reserve bid must be greater than or equal to the required amount of Non-Spinning Reserve; and

(ii) the amount of Non-Spinning Reserve bid for each Generating Unit, System Unit, or Curtailable Demand must be less than or equal to that Generating Unit's, System Unit's, Curtailable Demand's, or external import's ramp rate (or time to interruption in the case of a Load offering Demand reduction) times the difference between 10 minutes and the time to synchronize in the case of a Generating Unit, or to interruption in the case of a Load.

(b) The total Non-Spinning Reserve bid for each Generating Unit, System Unit, Curtailable Demand or external import of a System Resource is calculated by multiplying the reserve reservation bid price by the amount of Non-Spinning Reserve bid. Subject to any locational requirements, the ISO will accept the winning Non-Spinning Reserve bids in accordance with the following criteria:

$$Min \sum_{i,j} Totalbid_{ijt}$$

subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

and

$$Cap_{ijt} \leq Cap_{ijt} max$$

where:

$TotalBid_{ijt}$ = $Cap_{ijt} * CapRes_{ijt}$

Requirement = *Amount of Non-Spinning Reserve required by the ISO.*

SP 9.7.2 Non-Spinning Reserves Price Determination

The price payable to SCs for Non-Spinning Reserve made available in accordance with the ISO's Ancillary Services schedules shall, for each Generating Unit, System Unit, Curtailable Demand or external import of a System Resource concerned, be the Zonal Market Clearing Price for Non-Spinning Reserve calculated as follows:

$Pnonsp_{ijt} = MCP_x$

where:

the Zonal Market Clearing Price (MCP_{xt}) for Non-Spinning Reserve is the highest priced winning reservation bid of a Generating Unit, System Unit, Curtailable Demand or external import of a System Resource serving Demand in Zone X based on the reservation bid (i.e., $MCP_{xt} = Max(CapRes_{ijt})$ in Zone *X* for Settlement Period t). In the absence of Inter-Zonal Congestion, the Zonal Market Clearing Prices will be equal.

SP 9.8 Replacement Reserves Bid Evaluation and Pricing

SP 9.8.1 Replacement Reserves Bid Evaluation

(a) Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units, Curtailable Demands and external imports of System Resources with the Replacement Reserve bids which minimize the sum of the total Replacement Reserve bids of the Generating Units, System Units, Curtailable Demands and external imports of System Resources selected subject to two constraints:

(i) the sum of the selected amounts of Replacement Reserve bid must be greater than or equal to the required amount of Replacement Reserve; and

(ii) the amount of Replacement Reserve bid for each Generating Unit, System Unit, Curtailable Demand or external import of a System Resource must be less than or equal to that Generating Unit's, System Unit's, Curtailable Demand's or external import's ramp

rate (or time to interruption in the case of a Load offering Demand reduction) times the difference between 60 minutes and the time to synchronize in the case of Generating Unit, or to interruption in the case of Load.

(b) The total Replacement Reserve bid for each Generating Unit, System Unit, Curtailable Demand or external import of a System Resource is calculated by multiplying the reserve reservation bid price by the amount of Replacement Reserve bid. Subject to any locational requirements, the ISO will select the winning Replacement Reserve bids in accordance with the following criteria:

$$Min \sum_{i,j} Totalbid_{ijt}$$

subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

and

$$Cap_{ijt} \leq Cap_{ijt}max$$

where:

$TotalBid_{ijt}$ = $Cap_{ijt} * CapRes_{ijt}$

$Requirement$ = *Amount of Replacement Reserve required by the ISO.*

SP 9.8.2 Replacement Reserves Price Determination

The price payable to SCs for Replacement Reserve made available in accordance with the ISO's Ancillary Services schedules shall, for each Generating Unit, System Unit, Curtailable Demand or external import of a System Resource concerned, be the Zonal Market Clearing Price for Replacement Reserve calculated as follows:

$$Prepres_{ijt} = MCP_{xt}$$

where:

the Zonal Market Clearing Price (MCP_{xt}) for Replacement Reserve is the highest priced winning reservation bid of a Generating Unit, System Unit, Curtailable Demand or external import of a System Resource serving Demand in Zone X based on the reservation bid price (i.e., $MCP_{xt} = Max(CapRes_{ijt})$ in Zone X for Settlement Period t). In the absence of Inter-Zonal Congestion, the Zonal Market Clearing Prices will be equal.

SP 9.9 Existing Contracts – Ancillary Services Accountability

Certain Existing Contracts may have requirements for Ancillary Services which differ from the requirements of this SP 9. Each PTO will be responsible for recovering any deficits or crediting any surpluses associated with differences in assignment of Ancillary Services requirements, through its bilateral

arrangements or its Transmission Owner's Tariff. The ISO will not undertake the settlement or billing of any such differences under any Existing Contract.

SP 10 DAY/HOUR-AHEAD INTER-ZONAL CONGESTION MANAGEMENT

SP 10.1 Congestion Management Assumptions

The Inter-Zonal Congestion Management process is based upon the following assumptions:

(a) Inter-Zonal Congestion Management will ignore Intra-Zonal Congestion. Intra-Zonal Congestion will be managed in accordance with Tariff Section 7.2.6;

(b) Inter-Zonal Congestion Management will use a DC optimal power flow (OPF) program that uses linear optimization techniques with active power (MW) controls only; and

(c) transmission capacity reserved under Existing Contracts will not be subject to the ISO's Congestion Management procedures.

SP 10.2 Congestion Management Process

(a) Inter-Zonal Congestion Management will involve adjusting Schedules to remove potential violations of Inter-Zonal Interface Constraints, minimizing the Redispatch cost, as determined by the submitted Adjustment Bids that accompany the submitted Schedules. See the SBP for a general description of the use of Adjustment Bids to establish priorities.

(b) Inter-Zonal Congestion Management will not involve arranging or modifying trades between SCs. Each SC's portfolio will be kept in balance (i.e., its Generation plus external imports, as adjusted for Transmission Losses, and Inter-Scheduling Coordinator Energy Trades (whether purchases or sales) will still match its Demand plus external exports) after the adjustments. Market Participants will have the opportunity to trade with one another and to revise their Schedules during the first Congestion Management iteration in the Day-Ahead Market, and between the Day-Ahead Market and Hour-Ahead Market.

(c) Inter-Zonal Congestion Management will also not involve the optimization of SC portfolios within Zones (where such apparently non-optimal Schedules are submitted by SCs). Adjustments to individual SC portfolios within a Zone will be either incremental (i.e., an increase in Generation and external imports and a decrease in Demand and external exports) or decremental (i.e., a decrease in Generation and external imports and an increase in Demand and external exports), but not both.

(d) If Adjustment Bids are exhausted before Congestion is eliminated, the remaining Schedules will be adjusted *pro rata* except for those uses of transmission service under Existing Contracts, which are curtailed in accordance with SP 7.3 and SP 7.4.

SP 10.3 Congestion Management Pricing

(a) The Adjustment Bids that the SCs submit constitute implicit bids for transmission between Zones on either side of a Congested Inter-Zonal Interface. The ISO's Inter-Zonal

Congestion Management process will allocate Congested transmission to those users who value it the most and will charge all SCs for their allocated usage of Congested Inter-Zonal Interfaces on a comparable basis. All SCs within a Zone will see the same price for transmitting Energy across a Congested Inter-Zonal Interface, irrespective of the particular locations of their Generators, Demands and external imports/exports.

(b) The ISO will determine the prices for the use of Congested Inter-Zonal Interfaces using the Adjustment Bids. The ISO will collect Usage Charges from SCs for their Scheduled use of Congested Inter-Zonal Interfaces. If Adjustment Bids are exhausted and Schedules are adjusted *pro rata*, the ISO will apply a default Usage Charge calculated in accordance with Section 7.3.1.3 of the ISO Tariff.

(c) The ISO will rebate the Congestion revenues collected through the Usage Charges to the PTOs which own the Congested Inter-Zonal Interface in proportion to their respective ownership rights.

SP 11 CREATION OF THE REAL-TIME MERIT ORDER STACK

SP 11.1 Sources of Imbalance Energy

The following Energy Bids will be considered in the creation of the real-time merit order stack for Imbalance Energy:

(a) Supplemental Energy Bids submitted in accordance with the SBP;

(b) Ancillary Services Energy Bids (except for Regulation) submitted for specific Ancillary Services in accordance with the SBP for those resources which have been selected in the ISO's Ancillary Services auction to supply such specific Ancillary Services; and

(c) Ancillary Services Energy Bids (except for Regulation) submitted for specific Ancillary Services in accordance with the SBP for those resources which SCs have elected to use to self-provide such specific Ancillary Services and for which the ISO has accepted such self-provision.

SP 11.2 Stacking of the Energy Bids

The sources of Imbalance Energy described in SP 11.1 will be arranged in order of increasing Energy Bid prices to create a merit order stack for use in accordance with the DP. This merit order stack will be arranged without regard to the source of the Energy Bid except that Energy Bids associated with Spinning and Non-Spinning Reserve shall not be included in the merit order stack during normal operating conditions if the capacity associated with such bids has been designated as available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or

actual System Emergency. In the event of an unplanned Outage, a Contingency or threatened or actual System Emergency, all Energy Bids associated with Spinning and Non-Spinning Reserve may be included in the merit order stack. In the event of Inter-Zonal Congestion, separate merit order stacks will be created for each Zone. The information in the merit order stack shall be provided to the real-time dispatcher through the RTD Software.

Where, in any Settlement Interval, the highest decremental Energy Bid in the merit order stack is higher than the lowest incremental Energy Bid, the RTD Software will eliminate the Price Overlap by actually dispatching for all those incremental and decremental bids which fall within the overlap.

References to incremental Energy Bids include references to Demand reduction bids, and for the purpose of applying this algorithm a reduction in Demand shall be treated as an equivalent increase in Generation.

SP 11.3 Use of the Merit Order Stack

The merit order stack, as described in SP 11.2, can be used to supply Energy for:

(a) satisfying needs for Imbalance Energy (differences between actual and scheduled Generation, Demand and external imports/exports) in real time;

(b) managing Inter-Zonal Congestion in real time;

(c) supplying Energy necessary to allow resources providing Regulation service to return to the base point of their regulating ranges in real time;

(d) recovering Operating Reserves utilized in real time;

(e) procuring additional Voltage Support required from resources beyond their power factor ranges in real time; and

(f) Dispatching System Resources and Dispatchable Loads and increasing Generating Units' output to manage Intra-Zonal Congestion in real time.

SP 12 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

SETTLEMENT AND BILLING PROTOCOL (SABP)

SABP 1 OBJECTIVES, DEFINITIONS AND SCOPE

SABP 1.1 Objectives

The objective of this Protocol (and of Annex 1) is to inform Scheduling Coordinators, Participating TOs, Utility Distribution Companies, Metered Subsystems, and Operators of Reliability Must-Run Units of the manner in which the charges referred to in Section 11.1.6 of the ISO Tariff shall be calculated and settled and of the procedures regarding the billing, invoicing and payment of these charges.

SABP 1.2 Definitions

SABP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section is to a Section of the ISO Tariff. References to SABP are to this Protocol or to the stated paragraph of this Protocol. References to Annex 1 are to Annex 1 of this Protocol.

SABP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meanings set opposite them:

"Day 0" means the Trading Day to which the Settlement Statement or Settlement calculation refers. For example "Day 41" shall mean the 41st day after that Trading Day and similar expressions shall be construed accordingly.

"Fed-Wire" means the Federal Reserve Transfer System for electronic funds transfer.

"Interim Black Start Agreement" means an agreement entered into between the ISO and a Participating Generator (other than a Reliability Must-Run Agreement) for the provision by the Participating Generator of Black Start capability and Black Start Energy on an interim basis until the introduction by the ISO of its Black Start auction (or until terminated earlier by either party in accordance with its terms).

"ISO Surplus Account" means the account established by the ISO pursuant to SABP 6.5.

(b) Participating TOs;

(c) Black Start Generators;

(d) Utility Distribution Companies, and

(e) Metered Subsystems.

The Settlement, billing and payment process between the ISO, Scheduling Coordinators, Participating TOs, Black Start Generators, Utility Distribution Companies, and Metered Subsystems shall be in accordance with Sections 11.3 to 11.24 inclusive of the ISO Tariff. References in those Sections to Scheduling Coordinators shall also apply to Participating TOs which receive Settlement Statements from the ISO in relation to the transactions referred to in those Settlement Statements but excluding the transactions referred to in Annex 1. Notwithstanding SABP 1.2.3(a), references in Sections 11.3 to 11.24 inclusive of the ISO Tariff to Scheduling Coordinators, ISO Debtors and ISO Creditors shall also apply to Black Start Generators which receive Settlement Statements from the ISO in relation to transactions under their Interim Black Start Agreements.

Annex 1 of this Protocol applies to the ISO, Owners of Reliability Must-Run Units and Participating TOs in relation to the billing and payment of amounts due under Reliability Must-Run Contracts and recovery of such amounts by the ISO from Participating Utilities. The provisions of this Protocol shall not apply to Annex 1 unless otherwise specified.

SABP 1.3.2 Liability of the ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

SABP 2 OVERVIEW OF SETTLEMENT AND BILLING PROCESS

SABP 2.1 Settlement Software

The ISO Settlement software shall be audited by an independent firm of auditors competent to carry out audits of such software to determine its consistency with this Protocol and the ISO Tariff. In any dispute regarding Settlement calculations, a certificate of such firm of auditors that the ISO software is consistent with the ISO Tariff shall be prima facie proof that the charges shown in a Settlement Statement have been calculated in a method consistent with the ISO Tariff and this Protocol. Nothing in this section will be deemed to establish the burden of proof with respect to Settlement calculations in any proceeding.

SABP 2.2 ISO Accounts

SABP 2.2.1 Costs Associated with the ISO Trust Accounts

The ISO is authorized to establish and maintain bank accounts held in trust for Market Participants and obtain lines of credit and other banking facilities (not exceeding an aggregate amount set by

any of which may submit comments and objections to the ISO within two weeks of the date of posting of the draft on the ISO Home Page.

SABP 2.3.4 **Final Payments Calendar**

No later than October 31st in each year, the ISO will publish pursuant to Section 11.24.1 of the ISO Tariff the final ISO Payments Calendar for the following calendar year, after considering the comments and objections received from Scheduling Coordinators, Black Start Generators, Participating TOs and Owners. The final ISO Payments Calendar will be posted on the ISO Home Page.

SABP 2.3.5 **Update the Final Payments Calendar**

If as a result of a tariff amendment approved by FERC the final ISO Payments Calendar developed in accordance with SABP 2.3.3 and 2.3.4 above is rendered inconsistent with the timing set forth in the tariff, the ISO shall update the final ISO Payments Calendar to make it consistent with the tariff as approved by FERC on the date on which the tariff amendment goes into effect. The ISO shall simultaneously send out a notice to Market Participants that the final ISO Payments Calendar has been revised.

SABP 2.3.6 **Final Calendar Binding**

The final ISO Payments Calendar shall be binding on the ISO and on Scheduling Coordinators, Black Start Generators, Participating TOs and Owners.

SABP 3 **COMPUTATION OF CHARGES**

SABP 3.1 **Description of Charges to be Settled**

The ISO shall, based on the Settlement Quality Meter Data it has received, or, if Settlement Quality Meter Data is not available, based on the best available information or estimate it has received, calculate the following:

(a) the amount due from each Scheduling Coordinator for its share for the relevant month of the seven components of the Grid Management Charge in accordance with the formula located in Appendix F, Schedule 1, Part A of this Tariff. These Charges shall accrue on a monthly basis.

(b) the amount due from each Scheduling Coordinator for the Grid Operations Charge in accordance with Appendix F, Schedule 2 of this Tariff. This charge shall accrue on a monthly basis.

(c) the amount due from and/or owed to each Scheduling Coordinator for the Charge for each Ancillary Service in accordance with Appendix C, for each of the Settlement Periods of Day 0.

(f) the amount due from each Scheduling Coordinator for Wheeling Out and Wheeling Through Charges and the amount owed to each Participating TO for these charges in accordance with Appendix F, for each of the Settlement Periods of Day 0.

(g) the amounts due from/to Scheduling Coordinators for Voltage Support (supplemental reactive power charges) for each of the Settlement Periods of Day 0 in accordance with Appendix G.

(h) the monthly charges due from/to Scheduling Coordinators for long-term Voltage Support provided by Owners of Reliability Must-Run Units in accordance with Appendix G.

(i) the amounts due from/to Scheduling Coordinators for the provision of Black Start Energy from Reliability Must-Run Units for each of the Settlement Periods of Day 0 in accordance with Appendix G.

(j) the amounts due from/to Black Start Generators for the provision of Black Start Energy for each of the Settlement Periods of Day 0 in accordance with Appendix G.

(k) the amount due from each UDC or MSS, or from a Scheduling Coordinator delivering Energy for the supply of Gross Load not directly connected to the facilities of a UDC or MSS, for the High Voltage Access Charge and Transition Charge in accordance with operating procedures posted on the ISO Home Page. These charges shall accrue on a monthly basis.

(l) the amounts due from Scheduling Coordinators for FERC Annual Charges.

All of the data, information, and estimates the ISO uses to calculate these amounts shall be subject to the auditing requirements of Section 10.5 of the ISO Tariff.

The ISO shall calculate these amounts using the software referred to in SABP 2.1 except in cases of system breakdown when it shall apply the procedures set out in SABP 9 (Emergency Procedures).

SABP 3.1.1 Additional Charges and Payments

The ISO shall be authorized to levy additional charges or payments as special adjustments in regard to:

(a) amounts required to round up any invoice amount expressed in dollars and cents to the nearest whole dollar amount in order to clear the ISO Clearing Account. These charges will be allocated amongst Scheduling Coordinators over an interval determined by the ISO and pro rata based on metered Demand (including exports) during that interval;

SABP 4.4.5 **ISO Contact**

If the ISO does not agree with the amount claimed or if it requires additional information, it shall make reasonable efforts (taking into account the time it received the notice of dispute and the complexity of the issue involved) to contact the relevant Scheduling Coordinator, Black Start Generator or Participating TO to resolve the issue before issuing the Final Settlement Statement. If it is not possible to contact the relevant party, the ISO shall issue the Final Settlement Statement without taking into account the dispute notice.

SABP 4.4.6 **Payment Pending Dispute**

Each Scheduling Coordinator, Black Start Generator or Participating TO which receives an invoice shall pay any net debit and shall be entitled to receive any net credit shown in the invoice on the Payment Date, whether or not there is any dispute regarding the amount of the debit or credit. The provisions of Section 13 (Dispute Resolution) of the ISO Tariff shall apply to the disputed amount.

SABP 4.5 **Settlement Statement Re-runs**

SABP 4.5.1 **Notice**

If a Scheduling Coordinator, Black Start Generator or Participating TO, (having made reasonable efforts to resolve with the ISO any dispute relating to a Preliminary Settlement Statement pursuant to SABP 4.4) requires a Settlement Statement Re-run, it shall send at any time to the ISO Governing Board a notice in writing.

SABP 4.5.2 **ISO Tariff**

The provisions of Sections 11.6.3, 11.6.3.1, 11.6.3.2 and 11.6.3.3 of the ISO Tariff relating to Settlement Statement Re-runs shall apply to all Scheduling Coordinators, Black Start Generators or Participating TOs who require a Settlement Re-run in accordance with this SABP 4.5.

SABP 5 **INVOICES**

The ISO shall provide on the day specified in the ISO Payments Calendar an invoice in the format set out in SABP Appendix I showing:

(a) amounts which according to each of the Preliminary and Final Settlement Statements of that Billing Period are to be paid from or to each Scheduling Coordinator, Black Start Generator or Participating TO;

(b) the Payment Date, being the date on which such amounts are to be paid or received and the time for such payment; and

(c) details (including the account number, bank name and Fed-Wire transfer instructions) of the ISO Clearing Account to which any amounts owed by the Scheduling Coordinator, Black Start Generator or Participating TO are to be paid.

excess will be credited to the Surplus Account pursuant to SABP 6.5.2(a).

(c) The funds referred to in SABP 6.5.2(a) pertaining to default Interest referred to in SABP 6.10.5 shall first be applied towards any unpaid creditor balances for the trade month in which the default Interest was assessed and second to any other unpaid creditor balances. Only after all unpaid creditor balances are satisfied in full will any excess funds pertaining to default Interest be credited to the Surplus Account pursuant to SABP 6.5.2(a).

SABP 6.5.3 Distribution of Funds

In the event that there are funds in the ISO Surplus Account in excess of an amount to be determined by the ISO Governing Board and noticed by the ISO to Market Participants, the amount of such excess will be distributed to Scheduling Coordinators using the same method of apportioning the refund as the method employed in apportioning the liability for the Grid Management Charge.

SABP 6.5.4 Trust

All amounts standing to the credit of the ISO Surplus Account will be held at all times on trust for Market Participants in accordance with this Protocol.

SABP 6.6 System Failure

SABP 6.6.1 At ISO Debtor's Bank

If any ISO Debtor becomes aware that a payment will not, or is unlikely to be, remitted to the ISO Bank by 10:00 am on the relevant Payment Date for any reason (including failure of the Fed-Wire or any computer system), it shall immediately notify the ISO, giving full details of the payment delay (including the reasons for the payment delay). The ISO Debtor shall make all reasonable efforts to remit payment as soon as possible, by an alternative method if necessary, to ensure that funds are received for value no later than 10:00 am on the Payment Date, or as soon as possible thereafter.

SABP 6.6.2 At the ISO's Bank

In the event of failure of any electronic transfer system affecting the ISO Bank, the ISO shall use reasonable efforts to establish alternative methods of remitting funds to the ISO Creditors' Settlement Accounts by close of banking business on that Payment Date, or as soon as possible thereafter. The ISO shall notify the ISO Debtors and the ISO Creditors of occurrence of the system failure and the alternative methods and anticipated time of payment.

SABP 6.7 Payment Default

Subject to SABP 6.8, if by 10:00 am on a Payment Date the ISO, in its reasonable opinion, believes that all or any part of any amount due to be remitted to the ISO Clearing Account by any Scheduling

APPENDIX B

GRID OPERATIONS CHARGE COMPUTATION

B 1 Purpose of charge

The Grid Operations Charge is a charge which recovers Redispatch costs incurred due to Intra-Zonal Congestion pursuant to Section 7.3.2 of the ISO Tariff. The Grid Operations Charge is paid by or charged to Scheduling Coordinators in order for the ISO to recover and properly redistribute the costs of adjusting the Balanced Schedules submitted by Scheduling Coordinators.

B 2 Fundamental formulae

B 2.1 Payments to SCs with incremented schedules

When it becomes necessary for the ISO to increase the output of a Scheduling Coordinator's Generating Unit$_i$ or System Resource$_i$ or reduce a Curtailable Demand$_i$ in order to relieve Congestion within a Zone, the ISO will pay the Scheduling Coordinator. The amount that ISO pays the Scheduling Coordinator$_j$ is the price specified in the Scheduling Coordinator's Imbalance Energy bid for the Generating Unit$_i$ or System Resource$_i$ or Curtailable Demand$_i$ multiplied by the quantity of Energy Dispatched. The formula for calculating the payment to Scheduling Coordinator$_j$ for each block$_b$ of Energy of its bid curve in Trading Interval$_t$ is:

$$INC_{bijt} = adjinc_{bijt} * \Delta inc_{bijt}$$

B 2.1.1 Total Payment for Trading Interval

The formula for calculating payment to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ has been increased or Curtailable Demand$_i$ reduced for all the relevant blocks$_b$ of Energy in the Imbalance Energy bid curve of that Generating Unit or System Resource or Curtailable Demand in the same Trading Interval$_t$ is:

$$PayTI_{ijt} = \sum_{b} INC_{bijt}$$

B 2.2 Charges to Scheduling Coordinators with decremented schedules

When it becomes necessary for the ISO to decrease the output of a Scheduling Coordinator's Generating Unit$_i$ or System Resource$_i$ in order to relieve Congestion within a Zone, the ISO will make a charge to the Scheduling Coordinator. The amount that the ISO will charge Scheduling Coordinator$_j$ for decreasing the output of Generating Unit$_i$ is

the decremental reference price specified for the Scheduling Coordinator as determined in accordance with Section 7.2.6.1 multiplied by the quantity of Energy Dispatched. The amount that the ISO will charge Scheduling Coordinator$_j$ for decreasing the output of System Resource$_i$ is the price specified in the Scheduling Coordinator's Imbalance Energy bid for System Resource$_i$ multiplied by the quantity of Energy Dispatched. The formula for calculating the

charge to Scheduling Coordinator$_j$ for each block$_b$ of Energy in its decremental reference price or Imbalance Energy Bid in Trading Interval$_t$ is:

$$DEC_{bijt} = adjdec_{bijt} * \Delta dec_{bijt}$$

B 2.2.1 Total Charge for Trading Interval

The formula for calculating the charge to Scheduling Coordinator$_j$ whose Generating Unit$_j$ or System Resource$_i$ has been decreased for all the relevant blocks$_b$ of Energy at the decremental reference price for Generating Unit$_j$, or Imbalance Energy bid for System Resource$_i$ in the same Trading Interval$_t$ is:

$$ChargeTI_{ijt} = \sum_b DEC_{bijt}$$

B 2.3 Not Used

B 2.4 Net ISO Redispatch costs

The Trading Interval net Redispatch cost encountered by ISO to relieve Intra-Zonal Congestion is the sum of the amounts paid by the ISO to those Scheduling Coordinators whose Generation or System Resource was increased or Curtailable Demand was decreased during the Trading Interval less the sum of the amounts received by the ISO from those Scheduling Coordinators whose Generating Units or System Resource were decreased during the Trading Interval. The fundamental formula for calculating the net Redispatch cost is:

$$REDISP_{CONGt} = \sum_j PayTI_{ijt} - \sum_i ChargeTI_{ijt}$$

Note that $REDISP_{CONGt}$ can be either positive or negative. This means that it is possible for the ISO to generate either a net cost or a net income, for any given Trading Interval. In the event the ISO does not make use of equal amounts of incremental and decremental dispatched MWHs, then the net Redispatch cost becomes the sum of the amounts paid (or charged) by the ISO to those Scheduling Coordinators whose Generation or System Resource was increased (or decreased) or Curtailable Demand was decreased (or increased) during the Trading Interval less the sum of the amounts received by the ISO from Scheduling Coordinators through the Imbalance Energy Market.

B 2.5 Grid Operations Price

The grid operations price is the Trading Interval rate used by the ISO to apportion net Trading Interval Redispatch costs to Scheduling Coordinators within the Zone with Intra-Zonal Congestion. The grid operations price is calculated using the following formula:

$$GOP_t = \frac{REDISP_{CONG_t}}{\sum_j QCharge_{jt} + \sum_j Export_{jt}}$$

B 2.6 **Grid Operations Charge**

The Grid Operations Charge is the vehicle by which the ISO recovers the net Redispatch costs. It is allocated to each Scheduling Coordinator in proportion to the Scheduling Coordinator's Demand in the Zone with Intra-Zonal Congestion and exports from the Zone with Intra-Zonal Congestion. The formula for calculating the Grid Operations Charge for Scheduling Coordinator$_j$ in Trading Interval$_t$ is:

$$GOC_{jt} = GOP_t * \left(QCharge_{jt} + EXPORT_{jt}\right)$$

B 3 **Meaning of terms of formulae**

B 3.1 **INC$_{bijt}$ - $**

The payment from the ISO due to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ is increased or Curtailable Load$_i$ is reduced within a block$_b$ of Energy in its Imbalance Energy bid in Trading Interval$_t$ in order to relieve Intra-Zonal Congestion.

B 3.2 **adjinc$_{bijt}$ - $/MWh**

The incremental cost for the rescheduled Generating Unit$_i$ or System Resource$_i$ or Curtailable Load$_i$ taken from the relevant block$_b$ of Energy in the Imbalance Energy bid submitted by the Scheduling Coordinator$_j$ or generated by the ISO for the Trading Interval$_t$.

B 3.3 **Δincbijt - MW**

The amount by which the Generating Unit$_i$ or System Resource$_i$ or Curtailable Load$_i$ of Scheduling Coordinator$_j$ for Trading Interval$_t$ is increased by the ISO within the relevant block$_b$ of Energy in its Imbalance Energy bid.

B 3.4 **PayTI$_{jit}$ - $**

The Trading Interval payment to Scheduling Coordinator$_j$ whose Generating Unit$_i$ has been increased or System Resource$_i$ or Curtailable Load$_i$ reduced in Trading Interval$_t$ of the Trading Day.

B 3.5 **DEC$_{bijt}$ - $**

The charge to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ is decreased for Trading Interval$_t$ within a block$_b$ of Energy at the decremental reference price for Generating Unit$_i$ or in the Imbalance Energy bid for System Resource$_i$.

B 3.6 **$adjdec_{bijt}$ - $/MWh**

The decremental cost for the rescheduled Generating $Unit_i$ or System $Resource_i$ taken from the relevant $block_b$ of Energy at the decremental reference price for Generating $Unit_i$ or Imbalance Energy bid for System $Resource_i$ submitted by Scheduling $Coordinator_j$ or generated by the ISO for the Trading $Interval_t$.

B 3.7 **Δdec_{bijt} - MW**

The amount by which the Generating $Unit_i$ or System $Resource_i$ of Scheduling $Coordinator_j$ for Trading $Interval_t$ is decreased by ISO within the relevant $block_b$ of Energy at the decremental reference price for Generating $Unit_i$ or Imbalance Energy bid for System $Resource_i$.

B 3.8 **$ChargeTI_{ijt}$ - $**

The Trading Interval charge to Scheduling $Coordinator_j$ whose Generating $Unit_i$ or System $Resource_i$ has been decreased in Trading $Interval_t$ of the Trading Day.

B 3.9 **Not Used**

B 3.10 **Not Used**

B 3.10.1 **Not Used**

B 3.10.2 **Not Used**

B 3.11 **$REDISP_{CONGt}$ - $**

The Trading Interval net cost to ISO to redispatch in order to relieve Intra-Zonal Congestion during Trading $Interval_t$.

B 3.12 **GOP_t - $/MWh**

The Trading Interval grid operations price for Trading $Interval_t$ used by the ISO to recover the costs of Redispatch for Intra-Zonal Congestion Management.

B 3.13 **GOC_{jt} - $**

The Trading Interval Grid Operations Charge by the ISO for Trading $Interval_t$ for Scheduling $Coordinator_j$ in the relevant Zone with Intra-Zonal Congestion.

B 3.14 **$QCHARGE_{jt}$ – MWh**

The Trading Interval metered Demand within a Zone for Trading $Interval_t$ for Scheduling $Coordinator_j$ whose Grid Operations Charge is being calculated.

B 3.15 **$EXPORT_{jt}$ – MWh**

The total Energy for Trading $Interval_t$ exported from the Zone to a neighboring Control Area by Scheduling $Coordinator_j$.

APPENDIX C

ANCILLARY SERVICES CHARGES COMPUTATION

C 1 Purpose of charges

The Ancillary Services charges reimburse the ISO for the costs of purchasing Ancillary Services in the Day-Ahead and Hour-Ahead Markets. Each Scheduling Coordinator that does not self-provide Ancillary Services must purchase these services from the ISO. The ISO will in turn purchase these Ancillary Services from Scheduling Coordinators in the markets. Ancillary Services purchased and resold by the ISO includes Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve. Any references in this Appendix C to the Ancillary Service "Regulation" shall be read as referring to "Regulation Up" or "Regulation Down".

This Appendix C also addresses the payments by ISO to Scheduling Coordinators for the Dispatch of energy from Dispatched Ancillary Services Units and for the Dispatch of Supplemental Energy in the Real Time Market. The ISO recovers the costs of real-time Dispatch of such energy through the Imbalance Energy charges described in Appendix D of this Protocol.

The reference to a Scheduling Coordinator by Zone refers to the Demand of that Scheduling Coordinator which is located in the Zone. A Generation Unit, Load, or System Resource located in another Control Area is considered to be located in the Zone in which its contract path enters the ISO Controlled Grid.

The ISO will purchase Ancillary Services for each Trading Interval in both the Day-Ahead and Hour-Ahead Markets. Separate payments will be calculated for each service for each Trading Interval and in each market for each Generating Unit, Load and System Resource. The ISO will then calculate a total payment for each Scheduling Coordinator for each Trading Interval for each service for each Zone in each market for all the Generating Units, Loads and System Resources that the Scheduling Coordinator represents. The ISO will charge Scheduling Coordinators for Ancillary Services, other than for energy, which they purchase from the ISO by calculating and applying charges to each Scheduling Coordinator for each Trading Interval for each service in each Zone in each market.

The ISO will allocate the Ancillary Services capacity charges, for both the Day-Ahead Market and the Hour-Ahead Market, on a Zonal basis if the Day-Ahead Ancillary Services Market is procured on a Zonal basis. The ISO will allocate the Ancillary Services capacity charges, for both the Day-Ahead Market and the Hour-Ahead Market, on an ISO Control Area wide basis if the Day-Ahead Ancillary Services Market is defined on an ISO Control Area wide basis.

C 2 Fundamental formulas

C 2.1 ISO payments to Scheduling Coordinators

C 2.1.1 Day-Ahead Market

(a) *Regulation*. When the ISO purchases Regulation capacity in the Day-Ahead Market, Scheduling Coordinators for Generating Units that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit which provides Regulation capacity over a given Trading Interval will be the total quantity of Regulation capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. The required Regulation capacity is defined in the Ancillary Services Requirements Protocol. Regulation Up and Regulation Down payments shall be calculated separately. This payment for Scheduling Coordinator j for providing Regulation Up capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCUpPayDA_{ijxt} = AGCUpQDA_{ijxt} * PAGCUpDA_{xt}$$

This payment for Scheduling Coordinator j for providing Regulation Down capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCDownPayDA_{ijxt} = AGCDownQDA_{ijxt} * PAGCDownDA_{xt}$$

The total Regulation Up payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$AGCUpPayTotalDA_{jxt} = \sum_{i} AGCUpPayDA_{ijxt}$$

The total Regulation Down payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$AGCDownPayTotalDA_{jxt} = \sum_{i} AGCDownPayDA_{ijxt}$$

(b) Spinning Reserve. When ISO purchases Spinning Reserve capacity in the Day-Ahead Market. Scheduling Coordinators for Generating Units and System Resources that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit or System Resource which provides Spinning Reserve capacity over a given Trading Interval will be the total quantity of Spinning Reserve capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. The required Spinning Reserve capacity is defined in the Ancillary Services Requirements Protocol. This payment for Scheduling Coordinator j for providing Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$SpinPayDA_{ijxt} = SpinQDA_{ijxt} * PSpinDA_{xt}$$

The total Spinning Reserve payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$SpinPayTotalDA_{jxt} = \sum_{i} SpinPayDA_{ixt}$$

(c) Non-Spinning Reserve. When the ISO purchases Non-Spinning Reserve capacity in the Day-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Non-Spinning Reserve capacity over a given Trading Interval will be the total quantity of Non-Spinning Reserve capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. The required Non-Spinning Reserve capacity is defined in the Ancillary Services Requirements Protocol. This payment for Scheduling Coordinator j for providing Non-Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$NonSpinPayDA_{ijxt} = NonSpinQDA_{ijxt} * PNonSpinDA_{xt}$$

The total Non-Spinning Reserve payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$NonSpinPayTotalDA_{jxt} = \sum_{i} NonSpinPayDA_{ijxt}$$

(d) Replacement Reserve. When the ISO purchases Replacement Reserve capacity in the Day-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Replacement Reserve capacity over a given Trading Interval will be the total quantity of Replacement Reserve capacity provided times the Zonal Market Clearing Price for thatTrading Interval in that Zone. The required Replacement Reserve capacity is defined in the Ancillary Services Requirements Protocol. This payment for Scheduling Coordinator j for providing Replacement Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$ReplPayDA_{ijxt} = ReplQDA_{ijxt} * PReplDA_{xt}$$

The total Replacement Reserve payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$ReplPayTotalDA_{jxt} = \sum_{i} ReplPayDA_{ijxt}$$

C 2.1.2 Hour-Ahead Market

(a) Regulation. When the ISO purchases Regulation capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units that provide this capacity will receive payment for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit which provides Regulation capacity over the Trading Interval will be the total quantity of Regulation capacity provided times the Zonal Market Clearing

Price for that Trading Interval in that Zone. The required Regulation capacity is defined in the Ancillary Services Requirements Protocol. Regulation Up and Regulation Down payments shall be calculated separately. This payment for Scheduling Coordinator j for providing Regulation Up capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCUpPayHA_{ijxt} = AGCUpQIHA_{ijxt} * PAGCUpHA_{xt}$$

This payment for Scheduling Coordinator j for providing Regulation Down capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCDownPayHA_{ijxt} = AGCDownQIHA_{ijxt} * PAGCDownHA_{xt}$$

When a Scheduling Coordinator buys back, in the Hour-Ahead Market, Regulation capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Regulation capacity bought back times the Zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Regulation Up capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCUpReceiveHA_{ijxt} = AGCUpQDHA_{ijxt} * PAGCUpHA_{xt}$$

This payment to the ISO from Scheduling Coordinator j to buy back Regulation Down capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCDownReceiveHA_{ijxt} = AGCDownQDHA_{ijxt} * PAGCDownHA_{xt}$$

The total Regulation payment for the Trading Interval of the Hour-Ahead Market to each Scheduling Coordinator for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Regulation bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$AGCUpPayTotalHA_{jxt} = \sum_{i} AGCUpPayHA_{ijxt} - \sum_{i} AGCUpReceiveHA_{ijxt}$$

$$AGCDownPayTotalHA_{jxt} = \sum_{i} AGCDownPayHA_{ijxt} - \sum_{i} AGCDownReceiveHA_{ijxt}$$

(b) Spinning Reserve. When the ISO purchases Spinning Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units and System Resources that provide this capacity will receive payments for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit or System Resource which provides Spinning Reserve capacity over the Trading Interval will be the total quantity of Spinning Reserve capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$SpinPayHA_{ijxt} = SpinQIHA_{ijxt} * PSpinHA_{xt}$$

When a Scheduling Coordinator buys back in the Hour-Ahead Market Spinning Reserve capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Spinning Reserve capacity bought back times the Zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$SpinReceiveHA_{ijxt} = SpinQDHA_{ijxt} * PSpinHA_{xt}$$

The total Spinning Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Spinning Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$SpinPayTotalHA_{jxt} = \sum_{i} SpinPayHA_{ijxt} - \sum_{i} SpinReceiveHA_{ijxt}$$

(c) Non-Spinning Reserve. When the ISO purchases Non-Spinning Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payment for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Non-Spinning Reserve capacity over the Trading Interval will be the total quantity of Non-Spinning

Reserve capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Non-Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$NonSpinPayHA_{ijxt} = NonSpinQIHA_{ijxt} * PNonSpinHA_{xt}$$

When a Scheduling Coordinator buys back in the Hour-Ahead Market Non-Spinning Reserve capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Non-Spinning Reserve capacity bought back times the Zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Non-Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$NonSpinReceiveHA_{ijxt} = SpinQDHA_{ijxt} * PNonSpinHA_{xt}$$

The total Non-Spinning Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Non-Spinning Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$NonSpinPayTotalHA_{jxt} = \sum_{i} NonSpinPayHA_{ijxt} - \sum_{i} NonSpinReceiveHA_{ijxt}$$

(d) Replacement Reserve. When the ISO purchases Replacement Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payments for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Replacement Reserve capacity over the Trading Interval will be the total quantity of Replacement Reserve capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Replacement Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$ReplPayHA_{ijxt} = ReplQIHA_{ijxt} * PReplHA_{xt}$$

When a Scheduling Coordinator buys back in the Hour-Ahead Market Replacement Reserve capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Replacement Reserve capacity bought back times the Zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Replacement Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$ReplReceiveHA_{ijxt} = ReplQDHA_{ijxt} * PReplHA_{xt}$$

The total Replacement Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Replacement Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$ReplPayTotalHA_{jxt} = \sum_{i} ReplPayHA_{ijxt} - \sum_{i} ReplReceiveHA_{ijxt}$$

C 2.2 ISO allocation of charges to Scheduling Coordinators

C 2.2.1 Day-Ahead Market

(a) Regulation. The ISO will charge the Zonal cost of providing Regulation capacity that is not self-provided by Scheduling Coordinators, in the Day-Ahead Market, through the application of a charge to each Scheduling Coordinator for each Trading Interval. This charge will be computed by multiplying the Regulation user rate for the Trading Interval by the Scheduling Coordinator's Regulation obligation, for which it has not self-provided, for the same period.

The Zonal Regulation user rate for the Day-Ahead Market is calculated by dividing the total cost to ISO of purchasing Regulation Capacity within the Zone, for the Trading Interval, by the total ISO Regulation MW purchases for the Trading Interval within the Zone. Regulation Up and Regulation Down payments shall be calculated separately.

The Day-Ahead Regulation Up user rate in Zone x for Trading Interval t is calculated as follows:

$$AGCUpRateDA_{xt} = \frac{\sum_{j} AGCUpPayTotalDA_{jxt}}{AGCUpPurchDA_{xt}}$$

where,

$AGCUpPayTotalDA_{ixt}$ = Total Regulation Up payments for the Settlement Period t in the Day-Ahead Market for the Zone x.

The Day-Ahead Regulation Down user rate in Zone x for Trading Interval t is calculated as follows:

$$AGCDownRateDAxt = \frac{\sum_{j} AGCDownPayTotalDAjxt}{AGCDownPurchDAxt}$$

where,

$AGCDownPayTotalDA_{jxt}$ = Total Regulation Down payments for the Settlement Period t in the Day-Ahead Market for the Zone x.

The Regulation capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$AGCUpChgDA_{jxt} = AGCUpOblig_{jxt} * AGCUpRateDA_{xt}$$

$$AGCDownChgDA_{jxt} = AGCDownOblig_{jxt} * AGCDownRateDA_{xt}$$

(b) Spinning Reserve. The ISO will charge the Zonal cost of providing Spinning Reserve capacity that is not self-provided by Scheduling Coordinators, in the Day-Ahead Market, through the application of a charge to each Scheduling Coordinator for each Trading Interval. This charge will be computed by multiplying the Spinning Reserve capacity user rate for the Trading Interval by the Scheduling Coordinator's Spinning Reserve obligation, for which it has not self-provided, for the same period. The Zonal Spinning Reserve capacity user rate for the Day-Ahead Market is calculated by dividing the total cost to ISO of purchasing Spinning Reserve capacity within the Zone, for the Trading Interval, by the total ISO Spinning Reserve MW purchases for the Trading Interval within the Zone. The Day-Ahead Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$SpinRateDA_{xt} = \frac{\sum_{j} SpinPayTotalDA_{jxt}}{SpinPurchDA_{xt}}$$

The Spinning Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$SpinChgDA_{jxt} = SpinOblig_{jxt} * SpinRateDA_{xt}$$

(c) Non-Spinning Reserve. The ISO will charge the Zonal cost of providing Non-Spinning Reserve capacity that is not self-provided by Scheduling Coordinators, in the Day-Ahead Market, through the application of a charge to each Scheduling Coordinator for each Trading Interval. This charge will be computed by multiplying the Non-Spinning Reserve capacity user rate for the Trading Interval by the Scheduling Coordinator's Non-Spinning Reserve obligation, for which it has not self-provided, for the same period.

The Zonal Non-Spinning Reserve capacity user rate for the Day-Ahead Market is calculated by dividing the total cost to ISO of purchasing Non-Spinning Reserve capacity within the Zone, for the Trading Interval, by the total ISO Non-Spinning Reserve MW purchases for the Trading Interval within the Zone. The Day-Ahead Non-Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$NonSpinRateDA_{xt} = \frac{\sum_{j} NonSpinPayTotalDA_{jxt}}{NonSpinPurchDA_{xt}}$$

The Non-Spinning Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$NonSpinChgDA_{jxt} = NonSpinOblig_{jxt} * NonSpinRateDA_{xt}$$

C 2.2.2 Hour-Ahead Market

(a) Regulation. The ISO will charge the Zonal net cost of providing Regulation capacity that is not self-provided by Scheduling Coordinators, in the Hour-Ahead Market through the application of a charge to each Scheduling Coordinator for the Trading Interval concerned. This charge will be computed by multiplying the Regulation user rate for the Trading Interval by the Scheduling Coordinator's Regulation obligation, for which it has not self-provided, for the same period.

The Zonal Regulation capacity user rate for the Hour-Ahead Market is calculated by dividing the total cost to the ISO of purchasing Regulation capacity within the Zone less any amounts payable to the ISO by Scheduling Coordinators for Regulation bought back from the ISO in the Hour-Ahead Market on behalf of resources located in the Zone, for the Trading Interval, by the total ISO Regulation capacity MW purchases for the Trading Interval within the Zone. Regulation Up and Down payments shall be calculated separately. The Hour-Ahead Regulation Up capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$AGCUpRateHA_{xt} = \frac{\sum_{j} AGCUpPayTotalHA_{jxt}}{AGCUpPurchHA_{xt}}$$

where,

$AGCUpPayTotalHa_{jxt}$= Totlal Regulation Up payments for the Settlement Period t in the Hour-Ahead Market for Zone x.

The Hour-Ahead Regulation Down capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$AGCDownRateHAxt \frac{\sum_{j} AGCDownPayTotalHAjxt}{AGCDownPurchHAxt}$$

where,

$AGCDownPayTotalHA_{xt}$ = Total Regulation Down payments for the Settlement Period t in the Hour-Ahead Market for Zone x.

The Regulation capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$AGCUpChgHA_{jxt} = (AGCUpOblig_{jxt} * AGCUpRateHA_{xt})$$

$$AGCDownChgHA_{jxt} = (AGCDownOblig_{jxt} * AGCDownRateHA_{xt})$$

(b) Spinning Reserve. The ISO will charge the Zonal net cost of providing Spinning Reserve capacity that is not self-provided by Scheduling Coordinators, in the Hour-Ahead Market, through the application of a charge to each Scheduling Coordinator for the Trading Interval. This charge will be computed by multiplying the Spinning Reserve capacity user rate for the Trading Interval by the Scheduling Coordinator's Spinning Reserve obligation, for which it has not self-provided, for the same period. The Zonal Spinning Reserve capacity user rate for the Hour-Ahead Market is calculated by dividing the total cost to ISO of purchasing Spinning Reserve capacity within the Zone less any amounts payable to the ISO by Scheduling Coordinators for Spinning Reserve bought back from the ISO in the Hour-Ahead Market on behalf of resources located in the Zone, for the Trading Interval, by the total ISO Spinning Reserve MW purchases for the Trading Interval within the Zone. The Hour-Ahead Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$SpinRateHA_{xt} = \frac{\sum_{j} SpinPayTotalHA_{jxt}}{SpinPurchHA_{xt}}$$

The Spinning Reserve capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$SpinChgHA_{jxt} = (SpinOblig_{jxt} * SpinRateHA_{xt})$$

(c) Non-Spinning Reserve. The ISO will charge the Zonal net cost of providing Non-Spinning Reserve capacity that is not self-provided by Scheduling Coordinators, in the Hour-Ahead Market, through the application of a charge to each Scheduling Coordinator for the Trading Interval. This charge will be computed by multiplying the Non-Spinning Reserve capacity user rate for the concerned Trading Interval by the Scheduling Coordinator's Non-Spinning Reserve obligation, for which it has not self-provided, for the same period. The Zonal Non-Spinning Reserve capacity user rate for the Hour-Ahead Market is calculated by dividing the total cost to ISO of purchasing Non-Spinning Reserve capacity within the Zone less any amounts

$DevReplOblig_{jxt}$ is the Scheduling Coordinator's obligation for deviation Replacement Reserve in Zone x in the Settlement Period t and $RemRepl_{jxt}$ is the Scheduling Coordinator's obligation for remaining Replacement Reserve in Zone x for Settlement Period t.

$SelfProv_{jxt}$ is Scheduling Coordinator's Replacement Reserve self-provision in Zone x for Settlement Period t.

$NetInterSCTrades_{jxt}$ is the sale of Replacement Reserve less the purchase of Replacement Reserve through Inter-Scheduling Coordinator Trades by Scheduling Coordinator j in Zone x for Settlement Period t.

Deviation Replacement Reserve for Scheduling Coordinator i in Zone x for Settlement Period t is calculated as follows:

If $ReplObligTotal_{xt} > TotalDeviations_{xt}$ then:

$$DevReplOblig_{xjt} = \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]$$

If $ReplObligTotal_{xt} < TotalDeviations_{xt}$ then:

$$DevReplOblig_{xjt} = \frac{ReplObligTotal_{xt}}{TotalDeviations_{xt}} * \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]$$

where,

$$TotalDeviations_{xt} = \sum_j \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]$$

$GenDev_{ijxt}$ = The deviation between scheduled and actual Energy generation for Generator i represented by Scheduling Coordinator I in Zone x during Settlement Period t as referenced in SABP Appendix D.

$LoadDev_{ijxt}$ = The deviation between scheduled and actual Load consumption for resource I represented by Scheduling Coordinator iin Zone x during Settlement Period t as referenced in SABP Appendix D.

$DevReplOblig_{xt}$ is total deviation Replacement Reserve in Zone x for Settlement Period t.

$ReplObligTotal_{xt}$ is total Replacement Reserve Obligation in Zone x for Settlement Period t.

Remaining Replacement Reserve for Scheduling Coordinator j in Zone x for Settlement Period t is calculated as follows:

$$RemRepl_{xjt} = \frac{MeteredDemand_{jxt}}{TotalMeteredDemand_{xt}} * TotalRemRepl_{xt}$$

where:

$MeteredDemand_{jxt}$ is the Scheduling Coordinator's total metered Demand excluding exports in Zone x for Settlement Period t.

$TotalMeteredDemand_{xt}$ is total metered Demand excluding exports in Zone x for Settlement Period t.

$TotalRemRepl_{xt} = Max[0, ReplObligTotal_{xt} - DevReplOblig_{xt}]$

C 2.2.4 Rational Buyer Adjustments

(a) If, in any Settlement Period, no quantity of Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve is purchased in the Day-Ahead Market or the Hour-Ahead Market due to the operation of Section 2.5.3.6 of the ISO Tariff, then in lieu of the user rate determined in accordance with Section C 2.2.1, C 2.2.2, or C 2.2.3, as applicable, the user rate for the affected Ancillary Service for that Settlement Period shall be determined as follows:

(i) If the affected market is a Day-Ahead Market, the user rate for the affected Ancillary Service shall be set at the lowest capacity reservation price for an unaccepted qualified capacity bid in a Day-Ahead Market for that Ancillary Service or for another Ancillary Service that meets the requirements for the affected Ancillary Service. If there are no such unaccepted bids, the user rate for the affected Ancillary Service shall be the lowest Market Clearing Price for the same Settlement Period established in the Day-Ahead Market for another Ancillary Service that meets the requirements for the affected Ancillary Service.

(ii) If the affected market is an Hour-Ahead Market, the user rate for the affected Ancillary Service shall be set at the lowest capacity reservation price for an unaccepted qualified capacity bid in the Hour-Ahead Market for the same Settlement Period for that Ancillary Service or for another Ancillary Service that meets the requirements for the affected Ancillary Service. If there are no such unaccepted bids, the user rate for the affected Ancillary Service shall be the user rate for the same Ancillary Service in the Day-Ahead Market in the same Settlement Period.

(b) With respect to each Settlement Period, in addition to the user rates determined in accordance with Sections C 2.2.1 through C 2.2.3, or Section C 2.2.4(a), as applicable, each Scheduling Coordinator shall be charged an additional amount equal to its proportionate share, based on total purchases by Scheduling Coordinators of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve of the amount, if any, by which (i) the total payments to Scheduling Coordinators

$AGCDownRateHA_{xt}$ - $/MW

The Hour-Ahead incremental (additional to Day-Ahead) Regulation Down capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.14 **$AGCUpChgHA_{jxt}$ - $**

The incremental (additional to Day-Ahead) Regulation Up charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t.

$AGCDownChgHA_{jxt}$ - $

The incremental (additional to Day-Ahead) Regulation Down charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t.

C 3.15 **$EnQPay_{ijxt}$ - $**

The payment for Scheduling Coordinator j for Instructed Imbalance Energy output from a resource i in the Real Time Market in Zone x for Trading Interval t.

C 3.16 **[NOT USED]**

C 3.17 **[NOT USED]**

C 3.18 **[NOT USED]**

C 3.19 **$SpinPayDA_{ijxt}$ - $**

The payment for Scheduling Coordinator j for providing Spinning Reserve capacity in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.20 **$SpinQDA_{ijxt}$ – MW**

The total quantity of Spinning Reserve capacity provided in the Day-Ahead Market by resource i represented by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.20A **$REPA_{ijxt}$ - $**

The Regulation Energy Payment Adjustment payable for real-time incremental or decremental Energy provided from Regulation resource i of Scheduling Coordinator j in Zone x in Trading Interval t.

C 3.22 **SpinPayTotalDA$_{jxt}$ - $**

The total payment to Scheduling Coordinator j for Spinning Reserve capacity in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.23 **SpinPayHA$_{ijxt}$ - $**

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Spinning Reserve capacity in the Hour-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.23.1 **SpinReceiveHA$_{ijxt}$ - $**

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.24 **SpinQIHA$_{ijxt}$ – MW**

The total quantity of incremental (additional to Day-Ahead) Spinning Reserve capacity provided in the Hour-Ahead Market by resource i represented by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.25 **SpinQDHA$_{ijxt}$ – MW**

The total quantity of decremental (less than Day-Ahead) Spinning Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.25.1 **PSpinHA$_{xt}$ -$/MW**

The Hour-Ahead Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Spinning Reserve capacity in Zone x for Trading Interval t. On Buyback condition, MCP applies charge for HA.

C 3.26 **SpinPayTotalHA$_{jxt}$ - $**

The total payment to Scheduling Coordinator j for incremental (additional to Day-Ahead) Spinning Reserve capacity in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.27 **SpinRateDA$_{xt}$ - $/MW**

The Day-Ahead Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.36 **NonSpinPayTotalDA$_{jxt}$ - $**

The total payment to Scheduling Coordinator j for providing Non-Spinning Reserve capacity in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.37 **NonSpinPayHA$_{ijxt}$ - $**

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Non-Spinning Reserve capacity in the Hour-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.37.1 **NonSpinReceiveHA$_{ijxt}$ - $**

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Non-Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.38 **NonSpinQIHA$_{ijxt}$ – MW**

The total quantity of incremental (additional to Day-Ahead) Non-Spinning Reserve capacity provided from resource i in the Hour-Ahead Market by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.39 **NonSpinQDHA$_{ijxt}$ – MW**

The total quantity of decremental (less than Day-Ahead) Non-Spinning Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.39.1 **PNonSpinHA$_{xt}$ - $/MW**

The Hour-Ahead Zonal Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Non-Spinning Reserve capacity for Trading Interval t in Zone x. On Buyback condition, MCP applies.

C 3.40 **NonSpinPayTotalHA$_{jxt}$ - $**

The total payment to Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Non-Spinning Reserve capacity in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Non-Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead market in Zone x for Trading Interval t.

C 3.41 **NonSpinRateDA$_{xt}$ - $/MW**

The Day-Ahead Non-Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.56 **$\mathbf{ReplRateDA_{xt}}$ - $/MW**

The Day-Ahead Replacement Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.57 **$\mathbf{ReplChgDA_{jxt}}$ - $**

The Replacement Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.58 **$\mathbf{ReplRateHA_{xt}}$ – $/MW**

The Hour-Ahead incremental (additional to Day-Ahead) Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.59 **$\mathbf{ReplChgHA_{jxt}}$ - $**

The incremental (additional to Day-Ahead) Replacement Reserve capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t.

C 3.60 **$\mathbf{ReplObligTotal_{xt}}$ – MW**

The net total Replacement Reserve capacity obligation in the Day-Ahead and Hour-Ahead Markets in Zone x for Trading Interval t as defined in the Ancillary Services Requirements Protocol. This net total obligation is the total obligation minus that self-provided.

C 3.61 **$\mathbf{ReplPayTotal_{jxt}}$ - $**

The total payment to Scheduling Coordinator j for providing Replacement Reserve capacity in the Day-Ahead and Hour-Ahead Markets in Zone x for Trading Interval t.

C 3.62 **$\mathbf{PavgRepl_{xt}}$ - $/MW**

The average price paid for Replacement Reserve capacity in the Day-Ahead Market and the Hour-Ahead Market in Zone x in Trading Interval t.

C 3.63 **$\mathbf{UnDispReplChg_{jxt}}$ - $**

The undispatched Replacement Reserve Capacity charge for Scheduling Coordinator j in the Day-Ahead and Hour-Ahead Markets in Zone x for Trading Interval t.

C 3.64 **$\mathbf{ReplOblig_{jxt}}$ – MW**

The Replacement Reserve capacity obligation in the Day-Ahead and Hour-Ahead Markets for Scheduling Coordinator j in Zone x for Trading Interval t as defined in the Ancillary Services Requirements Protocol.

C 3.65 **$\mathbf{ReplQDisp_{xt}}$ – MWh**

The Dispatched Replacement Reserve capacity in the Day-Ahead Market in Zone x in Trading Interval t.

Imbalance Energy is calculated as follows:

Generator Calculation for ISO Metered Entities:

$$IE_{i,h,o} = ME_{i,h,o} - SE_{i,h,o}$$

Load Calculation:

$$IE_{i,h,o} = SE_{i,h,o} - ME_{i,h,o}$$

System Resource Calculation:

$$IE_{i,h,o} = \sum_{1}^{k}\sum_{1}^{v} REAL_TIME_FLOW_{i,h,o,k,v} - SE_{i,h,o}$$

where,

$$SE_{i,h,o} = \frac{HAfin_{i,h}}{6}$$

$ME_{i,h,o}$ actual Meter Data for each resource *i* of each Settlement Interval *o* for each hour *h*.

Uninstructed Imbalance Energy is calculated as follows:

$$UIE_{i,h,o} = E_{i,h,o} - IIE_REG_{i,h,o}$$

where:

$$E_{i,h,o} = IE_{i,h,o} - \sum_{1}^{k} IIE_LOSS_{i,h,o,k} - \sum_{1}^{k} IIE_ML_{i,h,o,k} - \sum_{1}^{k}\sum_{1}^{m} IIE_PREDISPATCH_{i,h,o,k,m} - \sum_{1}^{k} RE_STANDARD_{i,h,o,k} - \sum_{1}^{k} RED_{i,h,o,k} - \sum_{1}^{k}\sum_{1}^{m} IIE_ECON_{i,h,o,k,m} - \sum_{1}^{k}\sum_{1}^{L} OOS_P_{i,h,o,k,L} - \sum_{1}^{k}\sum_{1}^{L} OOS_N_{i,h,o,k,L} - \sum_{1}^{k}\sum_{1}^{m} RIE_{i,h,o,k,m} - \sum_{1}^{k} IIE_RERATE_{i,h,o,k}$$

$IIE_REG_{i,h,o}$ is the Regulating Energy for resource *i* during Settlement Interval *o* in hour *h*

The amount of Instructed Imbalance Energy that will be deemed delivered in each Dispatch Interval will be based on Dispatch Instructions, as provided for in Section 2.5.22.6, and Final Hour-Ahead Schedules. The amount of Instructed Imbalance Energy to be settled in a Settlement Interval will be equal to the sum of all Instructed Imbalance Energy for all Dispatch Intervals within the relevant Settlement Interval. Instructed Imbalance Energy for each Settlement Interval shall be settled at the relevant Resource Specific Settlement Interval Ex Post Price. Generating Units, Participating Loads, and System Units may be eligible to recover their Energy Bid costs in accordance with Section 11.2.4.1.1.1. Instructed Imbalance Energy from System Resources shall be settled in accordance with Section 11.2.4.1.1.2.

The Instructed Imbalance Energy amount for each resource *i* in Settlement Interval *o* for hour *h* shall be determined as follows:

$$IIEC_{i,h,o} = \left(\sum_{1}^{k} \sum_{1}^{m} IIE_ECON_{i,h,o,k,m} + \sum_{1}^{k} \sum_{1}^{m} IIE_PREDISPATCH_{i,h,o,k,m} + \sum_{1}^{k} \sum_{1}^{m} RIE_{i,h,o,k,m} + \sum_{1}^{k} IIE_RERATE_{i,h,o,k} + \sum_{1}^{k} IIE_ML_{i,h,o,k} \right)$$

$$* STLMT_PRICE_{i,h,o} * (-1) + IIEC_OOS_{i,h,o} + REDC_{i,h,o} + IIEC_REG_{i,h,o}$$

Uninstructed Imbalance Energy is Imbalance Energy due to non-compliance with a Dispatch Instruction and shall be settled as provided for in SABP Appendix D Section 2.1.1.

D 2.2 Unaccounted for Energy Charge

The Unaccounted for Energy Charge on Scheduling Coordinator *g* in Settlement Interval *o* of Settlement Period *h* for each relevant Zone *j* is calculated in the following manner:

The UFE for each utility Service Area *s,* for which separate UFE calculation is performed, is calculated as follows,

$$UFE_{UDC,s,h,o} = \sum_{q \in UDC_s} I_{a,q,j,h,o} - \sum_{q \in UDC_s} E_{a,q,j,h,o} + \sum_{i \in UDC_s} G_{a,i,j,h,o} - \sum_{i \in UDC_s} L_{a,i,j,h,o} - TL_{s,h,o}$$

The Transmission Loss $TL_{s,h,o}$ in Settlement Interval *o* of Settlement Period *h* for utility Service Area *s* is calculated as follows:

$$TL_{s,h,o} = \left(\sum_i \left[G_{a,i,j,h,o} * (1 - GMM_{a,i,h}) \right] + \sum_q \left[I_{a,q,j,h,o} * (1 - GMM_{a,q,h}) \right] \right) * \frac{PFL_{s,h}}{\sum_s PFL_{s,h}}$$

Where $PFL_{s,h}$ are the Transmission Losses for utility Service Area *s* as calculated by a power flow solution for Settlement Period *h*, consistent with the calculation of final forecasted Generation Meter Multipliers.

Each metered demand point *z* in utility Service Area *s*, either ISO grid connected or connected through UDC *s*, is allocated a portion of the UFE as follows:

$$UFE_{i,j,h,o} = UFE_{UDC,s,h,o} * \frac{L_{i,j,h,o}}{\sum_{i \in UDC_s} L_{i,j,h,o}}$$

The UFE charge for Scheduling Coordinator *g* for Settlement Interval *o* of Settlement Period *h* in Zone *j* is calculated as a charge or payment using the applicable Zonal Settlement Interval Ex Post Price as follows:

$$UFEC_{g,j,h,o} = \left(\sum_{i \in SCg} UFE_{i,j,h,o,} \right) * ZONAL_EX_POST_PRICE_{j,h,o}$$

D 2.3 Hourly Ex Post Price

The Hourly Ex Post Price is the Energy-weighted average of the Dispatch Interval Ex Post Prices in each Zone *j* during each Settlement Period using the absolute value of Instructed Imbalance Energy procured from all Participating Generators, Participating Load, System Units, and System Resources in each applicable Dispatch Interval. The Hourly Ex Post Price may vary between Zones if Congestion is present.

D 2.6 Calculation of Unrecovered Cost Payment for Generators

As set forth in 11.2.4.1.1.1, Generator resources will be eligible to recover their bid costs (less than or equal to the Maximum Bid Level) for extra-marginal Energy dispatched above Pmin, if such costs are not recovered from the net of expected revenues earned through participation in the ISO's Real Time Market during the Trade Day (24-hour period). The expected market revenue deficits will only be included in the calculation for Settlement Intervals the resource operates within its relevant Tolerance Band. Additionally, resources will not recover the amount of these bid recovery costs allocated to each Settlement Interval in those Settlement Intervals in which the resource is operating outside of its relevant Tolerance Band.

The Unrecovered Cost Payment for each resource i shall be determined for the Trade Day *d* then evenly divided over n-Settlement Intervals as follows:

$$COST_RECOVERY_{i,d} = min(0, \sum_{1}^{h}\sum_{1}^{o}\left(PERF_STAT_{i,h,o} * MR_DEFICIT_{i,h,o} + MR_SURPLUS_{i,h,o}\right)$$

where,

$MR_DEFICIT_{i,h,o}$ = Market Revenue deficit for resource i in hour h for Settlement interval o based on the difference between the expected revenues earned in the Settlement Interval and and/or its bid cost;$MR_SURPLUS_{i,h,o}$= Market Revenue surplus for resource i in hour h for Settlement interval o based on the difference between the expected revenues earned in the Settlement Interval and/or its bid cost.

Resource i shall receive a share of its total cost recovery in each Settlement Interval o that is included in the $COST_RECOVERY_{i,d}$ calculation above if it operates within its relevant Tolerance Band during the relevant Settlement Interval o.

$$COST_RECOVERY_{i,h,o} = PERF_STAT_{i,h,o} * COST_RECOVERY_{i,d} / n$$

where,

n is the number of Settlement Intervals o that are included in the $COST_RECOVERY_{i,d}$ calculation for resource i in Trade Day d.

Calculation of Market Revenue Surplus or Deficit

The market revenue surplus or deficit for each resource i will be computed for each Settlement Interval o based on the difference between the revenues earned in the Settlement Interval at the relevant 10-minute Ex Post price and the resource's bid cost (less than or equal to the Maximum Bid Level) as follows:

$$MR_DIFF_{i,h,o} = \left(\sum_{1}^{k}\sum_{1}^{m} IIE_ECON_{i,h,o,k,m} + \sum_{1}^{k}\sum_{1}^{m} RIE_{i,h,o,k,m}\right) * STLMT_PRICE_{i,h,o} - BID_COST_{i,h,o} - BID_COST_RIE_{i,h,o}$$

for all incremental energy bid segments *m* with $IIE_PRICE_{i,h,o,k,m}$ and $RIE_PRICE_{i,h,o,k,m}$ less than or equal to the Maximum Bid Level and all decremental energy bid segments *m* with $IIE_PRICE_{i,h,o,k,m}$ and $RIE_PRICE_{i,h,o,k,m}$ greater than or equal to the Bid Floor.

$$MR_DEFICIT_{i,h,o} = min(0, MR_DIFF_{i,h,o})$$

$$MR_SURPLUS_{i,h,o} = \max(0, MR_DIFF_{i,h,o})$$

where,

$$BID_COST_{i,h,o} = \left(\sum_{1}^{k}\sum_{1}^{m} IIE_ECON_{i,h,o,k,m} * IIE_PRICE_{i,h,o,k,m}\right)$$

$$BID_COST_RIE_{i,h,o} = \sum_{1}^{k}\sum_{1}^{m} RIE_{i,h,o,k,m} * RIE_PRICE_{i,h,o,k,m}$$

D 2.6.1 Tolerance Band and Performance Check

The ISO shall determine the Tolerance Band for each Settlement Interval *o* for PGA resources based on the data from the Master File as follows:

$$TOLERANCE_BAND_{i,h,o} = \pm \max(FIX_LIM, TOL_PERCENT * P\max_i) / 6$$

where,
FIX_LIM is a fixed MW limit and is initially equal to 5 MW.
TOL_PERCENT is a fixed percentage and is initially equal to 3%.$Pmax_i$ is the maximum operating capacity in MW of resource *i* specified in the Master File.

The ISO shall determine the Tolerance Band for each Settlement Interval *o* for PLA resources as follows:

$$TOLERANCE_BAND_{i,h,o} = \pm\ max(FIX_LIM, TOL_PERCENT * HAfin_{i,h}) / 6$$

where $HAfin_{i,h}$ *is the* Final Hour Ahead Energy Schedule.

Resources must operate within their relevant Tolerance Band in order to receive any above-Ex Post Price payments. The ISO shall determine the performance status of the resource for each Settlement Interval o.

A resource shall have met its performance requirement if its $UIE_{i,h,o}$ is within its relevant Tolerance Band. A resource meeting its performance requirement in Settlement Interval o will have a $PERF_STAT_{i,h,o} = 1$. A resource that has not met its performance requirement in Settlement Interval *o* will have a $PERF_STAT_{i,h,o} = 0$.

Must offer resources that produce a quantity of Energy above Minimum Load due to an ISO Dispatch Instruction are not subject to the Tolerance Band requirement for purposes of receiving either Minimum Load Cost Compensation, as defined in section 5.11.6.1.1, or Bid Cost Recovery, as set forth in section 11.2.4.1.1.1. Accordingly, the $PERF_STAT_{i,h,o}$ for eligible must offer resources, as defined in section 5.11.6.1.1, shall be set to 1, irrespective of deviations outside of the Tolerance Band.

System Resources do not have a Tolerance Band. Non-Participating Load Agreement (PLA) load resources are not subject to the performance requirement.

D 2.6.2 Unrecovered Costs Neutrality Allocation

For each Settlement Interval *o*, the total Unrecovered Costs for Trade Day *d* shall be allocated pro-rata to each Scheduling Coordinator *g* based on its Metered Demand, calculated as follows:

$URC_ALLOC_{g,h,o} = M_{g,h,o} * Per\ Unit\ Price$

where,

$M_{g,h,o}$ = the Metered Demand in the ISO Control Area for Scheduling Coordinator *g* in Settlement Interval *o* for hour *h*;

$$Per\ Unit\ Price = \frac{-1 * \sum_{1}^{i} COST_RECOVERY_{i,h,o}}{\sum_{1}^{g} M_{g,h,o}}$$

D 2.6.3 Calculation of Unrecovered Cost Payment for System Resources

As set forward in Section 11.2.4.1.1.2, System Resources that are dispatched and deliver hourly-predispatched Instructed Imbalance Energy will be paid the higher of the simple average of the twelve Dispatch Interval Ex Post Prices for the hour or their Energy bid costs for the quantity of Energy delivered in each hour. The determination of the hourly uplift payment shall be determined as follows: (1) Market deficits or surpluses are calculated as the difference between the resource-specific price and the resource's (hourly) bid cost; (2) An hourly uplift payment will be determined for any amount less than zero; (3) This hourly amount will then be divided evenly by the relevant number of *n*-Settlement Intervals and paid this portion for each Settlement Interval of the hour.

$$TL_{i,h,o} = \sum_{1}^{k}\sum_{1}^{v} REAL_TIME_FLOW_{i,h,o,k,v} * (1 - GMMa_h)$$

The transmission loss charge will be calculated based on the following formulation:

$$TLC_{i,h,o} = -\sum_{1}^{k} IIE_LOSS_{i,h,o,k} * STLMT_PRICE_{i,h,o} + TL_{i,h,o} * STLMT_PRICE_{i,h,o}$$

D 2.8 Uninstructed Deviation Penalty Charges

For negative Uninstructed Deviation Penalty billable quantities where $UDP_BQ_{h,o} < 0$ and $ZONAL_EX_POST_PRICE_{j,h,o} > 0$,
$UDP_NEG_Amt_i\ AMT_{i\,h,o}$ =
-1 * $UDP_BQ_{i,h,o}$ * $ZONAL_EX_POST_PRICE_{j,h,o}$ * .5

For positive UDP billable quantities where $UDP_BQ_{i,h,o} > 0$ and $ZONAL_EX_POST_PRICE_{j,h,o} > 0$, then
$UDP_POS_AMT_{i,h,o} = UDP_BQ_{i,o,h} * ZONAL_EX_POST_PRICE_{j,h,o}$

where,

$UDP_BQ_{i,o,h}$ is the Uninstructed Deviation Penalty (UDP) billable quantity in MWh for a resource, or aggregated resource, denoted by i for Settlement Interval *o* of hour *h.*

$UDP_POS_AMT_{i,o,h}$ or $UDP_NEG_AMT_{i,o,h}$ are the penalty amounts in Dollars for either an aggregated or individual resource *i* for Settlement Interval *o* of hour *h.*

The ISO will not calculate UDP settlement amounts for Settlement Intervals when the corresponding Zonal Settlement Interval Ex Post Price is negative or zero.

For an MSS that has elected to follow its own Load, the Scheduling Coordinator for the MSS Operator will be assessed the Uninstructed Deviation Penalty charges based on the Deviation Band and Deviation Price in Section 23.12.2 of the ISO Tariff.

D 2.9 Minimum Load Cost Compensation

The ISO shall calculate a Must-Offer Generator's Minimum Load Cost Compensation (MLCC), pursuant to section 5.11.6.1.1 of the ISO Tariff, as the market revenue deficit below its Minimum Load Cost as follows:

$$MLCC_{i,h,o} = PERF_STAT_{i,h,o} * [\,min\,(0,\ MR_ML_{i,h,o} - MLC_{i,h,o})]$$

where:

D 3.23 **$E_{a,q,j,h,o}$ – MWh**

The total actual Energy export of Scheduling Coordinator g through Scheduling Point q in Settlement Interval o for Settlement Period *h*. This is deemed to be equal to the total scheduled Energy export during the same interval.

D 3.24 **[Not Used]**

D 3.25 **[Not Used]**

D 3.25.1 **[Not Used]**

D 3.26 **$UFEC_{jxt}$ – $**

The Unaccounted for Energy Charge for Scheduling Coordinator j in Zone x in Settlement Period t. It is the cost for the Energy difference between the net Energy delivered into each utility Service Area, adjusted for utility Service Area Transmission Losses (calculated in accordance with ISO Tariff Section 7.4.2), and the total metered Demand within that utility Service Area adjusted for distribution losses using Distribution System loss factors approved by the Local Regulatory Authority.

This Energy difference (UFE) is attributed to meter measurement errors, power flow modeling errors, energy theft, statistical Load profile errors, and distribution loss deviations.

D 3.27 **$UFE_{UDC,bkt}$ – MWh**

The Unaccounted for Energy (UFE) for utility Service Area k.

D 3.28 **UFE – MWh**

The portion of Unaccounted for Energy (UFE) allocated to metering point z.

D 3.29 **[Not Used]**

D 3.41 **[Not Used]**

D 3.42 **[Not Used]**

D 3.43 **[Not Used]**

D 3.44 **[Not Used]**

D 3.45 **[Not Used]**

D 3.46 **[Not Used]**

D 3.47 **[Not Used]**

D 3.48 **[Not Used]**

D 3.49 **$EX_POST_PRICE_{j,h,o,k}$ – $/MWh**

The Ex-Post Price in Dispatch Interval *k* of Settlement Interval *o* in Settlement Period *h* in Zone *j.*

D 3.50 **$HRLY_EX_POST_PRICE_{j,h}$ – $/MWh**

The energy-weighted Ex Post Price for Settlement Period *h* in Zone *j.*

D 3.51 **$STLMT_PRICE_{i,h,o}$ – $/MWh**

The 10-minute Settlement price (Resource-Specific Settlement Interval Ex Post Price) for resource *i* in the Settlement Interval *o* for the Settlement Period *h.*

D 3.52 **$SE_{i,h,o}$ – MWh**

The Scheduled Energy from resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.53 **$TOLERANCE_BAND_{i,h,o}$ – MWh**

The Tolerance Band limit for resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.54 **$IIE_ECON_{i,h,o,k,m}$ – MWh**

The dispatched incremental or decremental Instructed Imbalance Energy (IIE) for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h* for bid segment *m.*
Decremental Energy shall be represented as a negative quantity.

$IIE_ECON_{i,h,o,k,m}$ shall be comprised of any of the four *IIE_TYPE*'s: SUPP, SPIN, NSPN or RPLC and be associated with its respective $IIE_PRICE_{i,h,o,k,m}$

D 3.55 **$IIE_PRICE_{i,h,o,k,m}$ – $/MWh**

The bid price for energy bid segment *m* for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h* for bid segment *m*

D 3.56 **$IIE_PREDISPATCH_{i,h,o,k,m}$ – MWh**

The Settlement Period pre-dispatched Energy for resource *i* during Dispatch Interval *k* of Settlement Interval *o* of Settlement Period *h* for bid segment *m* (MWh).

D 3.57 **$RIE_{i,h,o,k,m}$ – MWh**

The Residual Energy for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h* for bid segment *m.*

D 3.58 **$RIE_PRICE_{i,h,o,k,m}$ – $/MWh**

The reference bid price for the Residual Energy for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h* for bid segment *m.*

D 3.59 **$OOS_PRICE_{i,h,o,k,L}$ – $/MWh**

The Settlement price for the Instructed Out of Stack Energy for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h* for index number *L.*

D 3.60 **$IIE_REG_{i,h,o}$ – MWh**

The Regulating Energy for resource *i* during Settlement Interval *o* in Settlement Period *h.*

D 3.61 **$IIE_PREDISPATCH_{i,h,p}$ – MWh**

The Settlement Period pre-dispatched Energy for resource *i* during Dispatch Interval *p* of Settlement Period *h.*

D 3.62 **$E_{i,h,o}$ – MWh**

Calculated as the difference of $IE_{i,h,o}$ and $IIE_TOTAL_{i,h,o,k}$ and is equal to the sum of Uninstructed Imbalance Energy and Regulating Energy of resource *i* during Settlement Interval *o* in Settlement Period *h.*

D 3.63 **$IIEC_{i,h,o}$ – $**

The Instructed Imbalance Energy payment (charge) for resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.64 **$IIEC_OOS_{i,h,o}$ – $**

The total OOS Energy payment (charge) for resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.65 **$IIEC_OOS_P_{i,h,o}$ – $**

The incremental Instructed OOS Imbalance Energy payment (charge) for resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.66 **$IIEC_OOS_N_{i,h,o}$ – $**

The decremental Instructed OOS Imbalance Energy payment (charge) for resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.67 **$IIE_LOSS_{i,h,o,k}$ – MWh**

The transmission loss self-provided Energy from resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h.*

D 3.68 **$IIE_ML_{i,h,o,k}$ – MWh**

The Imbalance Energy due to Minimum Load from resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h.*

D 3.69 **$IIE_TOTAL_{i,h,o,k}$ – MWh**

The total Instructed Imbalance Energy from all energy sources except Regulation for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h.*

D 3.70 **$IIE_RERATE_{i,h,o,k}$ – MWh**

The SLIC derated Pmin or Pmax value as a result of an SC modifying its operating output level for a given resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h.*

D 3.71 **$UIE_{i,h,o}$ – MWh**

The total Uninstructed Imbalance Energy from resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.72 **$UIE_1_{i,h,o}$ – MWh**

The Uninstructed Imbalance Energy attributed to non-compliance of *IIE_ECON* from resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.73 **$UIE_2_{i,h,o}$ – MWh**

The Uninstructed Imbalance Energy exclusive of UIE_1 from resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.74 **$UIEC_{i,h,o}$ – $**

The Uninstructed Imbalance Energy payment (charge) for resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.75 **$ZONAL_EX_POST_PRICE_{j,h,o}$ – $/MWh**

The energy weighted average Ex Post Price for Imbalance Energy for Zone *j* in Settlement Interval *o* for Settlement Period *h.*

D 3.76 **$ME_{i,h,o}$ – MWh**

The Metered Energy from resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.77 **$RED_{i,h,o,k}$ – MWh**

The Ramping Energy Deviation from resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h.*

D 3.78 **$REDC_{i,h,o}$ – $**

The Ramping Energy Deviation payment (charge) for resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.79 **$MR_ML_{i,h,o}$ – $**

The expected Real Time Market revenue from Minimum Load Energy for resource *i* in Settlement Interval *o* for Settlement Period *h.*

D 3.80 **$COST_RECOVERY_{i,d}$ – $**

The Unrecovered Cost Payment for resource *i* for Trading Day *d.*

D 3.81 **$MR_DIFF_{i,h,o}$**

is the market revenue surplus or deficit for resource *i* in Settlement Period *h* for Settlement Interval *o.*

D 3.82 **$MR_DEFICIT_{i,h,o}$ – $**

The market revenue deficit for resource *i* in Settlement Period *h* for Settlement Interval *o.*

D 3.83 **$MR_SURPLUS_{i,h,o}$ – $**

The market revenue surplus for resource *i* in Settlement Period *h* for Settlement Interval *o.*

D 3.84 **$PERF_STAT_{i,h,o}$ – True/False**

The performance status of resource *i* for Settlement Interval *o* of Settlement Period *h*. The performance status is equal to 1 (compliant) or 0 (non-compliant).

D 3.85 **$BID_COST_{i,h,o}$ – $**

The bid costs for IIE, except OOS Energy and RIE, for resource *i* in Settlement Period *h* for Settlement interval *o.*

D 3.86 **$BID_COST_RIE_{i,h,o}$ – $**

The bid costs for RIE for resource *i* in Settlement Period *h* for Settlement Interval *o.*

D 3.87 **$PREDISPATCH_PMT_{i,h,o}$ – $**

The unrecovered bid cost payment for a Settlement Period pre-dispatched System Resource *i* in Settlement Interval *o* for Settlement Period *h.*

D 3.88 **$EXCESS_COST_{i,h,o}$ – $**

The excess cost payment for resource *i* in Settlement Interval *o* for Settlement Period *h.*

D 3.89 **$TL_{i,h,o}$ – MWh**

The Transmission Loss Obligation for resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.90 **$EXCESS_COST_ALLOC_{g,h,o}$ – $**

The excess cost allocation for Scheduling Coordinator *g* in Settlement Period *h* for Settlement Interval *o.*

D 3.91 **$REAL_TIME_FLOW_{i,h,o,k,v}$ – MW*h***

The real-time actual flow for intertie resource *i* during Dispatch Interval *k* during Settlement Interval *o* of Settlement Period *h* for Real Time Flow Type index v. Real Time Flow Type index *v* must be one of the following Energy types: FIRM NFIRM, SUPP, WHEEL, DYN, ESPN, ENSPN, OOM, ERPLC.

D 3.92 **$RE_STANDARD_{i,h,o,k}$ – MWh**

The Standard Ramping Energy from resource *i* during Dispatch Interval *k* of Settlement Interval *o* of Settlement Period *h.*

D 3.93 **$OOS_P_{i,h,o,k,L}$ – MWh**

The incremental Out of Stack Energy for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h* for index number *L.*

D 3.94 **$OOS_N_{i,h,o,k,L}$ – MWh**

The decremental Out of Stack Energy for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h* for index number *L.*

D 3.95 **$URC_ALLOC_{g,h,o}$ – $**

The unrecovered cost neutrality allocation for Scheduling Coordinator *g* in Settlement Interval *o* for Settlement Period *h.*

D 3.96 **$IIE_TYPE_{i,h,o,k,m}$**

is the energy type for $IIE_ECON_{i,h,o,k,m}$. Energy type is one of the following: Supplemental, Spin, Non-Spin or Replacement Reserve Energy.

of Congestion shall (save to the extent that the transfer involves the use of transmission capacity represented by Existing Rights) receive a Usage Charge payment from the ISO calculated in accordance with the formulae described in Section E 2.1.

E 2.3 ISO Credits and Debits to Transmission Owners and FTR Holders of Usage Charge Revenues

E 2.3.1 Day-Ahead Market

The ISO will pay to the Participating TO n and FTR Holder n its share of the total net Usage Charge revenue for Trading Interval t in the Day-Ahead Market in accordance with the following formula:

$$PayUC_{ntd} = \sum_{y} \mu_{ytd} * K_{yn} * L_{ytd}$$

E 2.3.2 Hour-Ahead Market

The ISO will pay to the Participating TO n and FTR Holder n its share of the total net Usage Charge revenue for Trading Interval t in the Hour-Ahead Market in accordance with the following formula:

$$PayUC_{nth} = \sum_{y} \mu_{yth} * K_{yn} * (L_{yth} - L_{ytd})$$

Under normal operating conditions, (L_{yth} - L_{ytd}) is positive and Participating TOs and FTR Holders will receive a refund on the net Usage Charge for the relevant Trading Interval t in the Hour-Ahead Market.

E 2.3.3 Debits to Participating TOs and FTR Holders and Debits/Rebates to Scheduling Coordinators

If, after the close of the Day-Ahead Market, Participating TOs instruct the ISO to reduce interface limits based on operating conditions or an unscheduled transmission Outage occurs and as a result of either of those events, Congestion is increased and Available Transfer Capacity is decreased in the Inter-Zonal Interface in the Hour-Ahead Market, the (L_{yth} - L_{ytd}) will be negative. In this case:

(a) Participating TOs and FTR Holders will be charged for the Usage Charge payments they received for the relevant Trading Interval t in the Day-Ahead Market with respect to the reduced interface limits;

(b) Any Scheduling Coordinator whose Schedule was adjusted for the relevant Trading Interval t in the Hour-Ahead Market due to the reduced interface limits will be credited with μ_{yth} for each MW of the adjustment; and

(c) Each Scheduling Coordinator will be charged an amount equal to it proportionate share, based on Schedules in the Day-Ahead Market in the direction of Congestion, of the difference between $\mu_{yth}(L_{yth} - L_{ytd})$ and the total amount charged to Participating TOs and FTR Holders in accordance with item (a) above.

E 3.7.1 **$PayUC_{nth}$ ($)**

The amount calculated by the ISO to be paid to the Participating TO n (in respect of its Transmission Revenue Balancing Account) and FTR Holder n for the relevant Trading Interval t in the Hour-Ahead Market.

E 3.8 **μ_{ytd} ($/MW)**

The Day-Ahead Congestion price (shadow price) at Inter-Zonal Interface y for Trading Interval t. This price is calculated by the ISO's Congestion Management computer optimization algorithm.

E 3.8.1 **μ_{yth} ($/MW)**

The Hour-Ahead Congestion price (shadow price) at Inter-Zonal Interface y for Trading Interval t. This price is calculated by the ISO's Congestion Management computer optimization algorithm.

E 3.9 **K_{ytn} (%)**

The percentage of the Inter-Zonal Congestion revenue alocation for Participating TO n and FTR Holder n of the Congested Inter-Zonal interface y for the relevant Trading Interval t for both Day-Ahead and Hour-Ahead Markets.

E 3.10 **L_{ytd} (MW)**

The total loading of Inter-Zonal Interface y for Trading Interval t in the Day-Ahead as calculated by the ISO's Congestion Management optimization algorithm.

E 3.11 **L_{yth} (MW)**

The total loading of Inter-Zonal Interface y for Trading Interval t in the Hour-Ahead as calculated by the ISO's Congestion Management optimization algorithm.

APPENDIX F

WHEELING ACCESS CHARGES COMPUTATION

F 1 **Purpose of Charge**

The Wheeling Access Charge is paid by Scheduling Coordinators for Wheeling as set forth in Section 7.1.4 of the ISO Tariff. The ISO will collect the Wheeling revenues from Scheduling Coordinators on a Trading Interval basis and repay these to the Participating TOs based on the ratio of each Participating TO's Transmission Revenue Requirement to the sum of all Participating TOs' Revenue Requirements.

F 2 **Fundamental Formulae**

F 2.1 **ISO Charges on Scheduling Coordinators for Wheeling**

The ISO will charge Scheduling Coordinators scheduling a Wheeling Out or a Wheeling Through, the product of the Wheeling Access Charge and the total of the hourly schedules of Wheeling in MWh for each Trading Interval at each Scheduling Point associated with that transaction pursuant to Section 7.1.4 of the ISO Tariff.

F 2.1.1 **Wheeling Access Charge**

The Wheeling Access Charge for each Participating TO shall be as specified in Section 7.1.4 of the ISO Tariff.

F 2.1.2 **[Not Used]**

F 2.2 **ISO Payments to Transmission Owners for Wheeling**

The ISO will pay all Wheeling revenues to Participating TOs on the basis of the ratio of each Participating TO's Transmission Revenue Requirement ("TRR") (less the TRR associated with Existing Rights) to the sum of all Participating TOs' TRRs (less the TRRs associated with Existing Rights) as specified in Section 7.1.4.3 of the ISO Tariff. The Low Voltage Wheeling Access Charge shall be disbursed to the appropriate Participating TO. The sum to be paid to Participating TO_n for a Trading Interval is calculated as follows:

$$PayTO_n = \frac{TRR_n}{\sum_n TRR_n} * \sum_j totalWChrg_j$$

F 3 **Meaning of terms in formulae**

F 3.1 **$WABC_q$** **($/kWh)**

The Weighted Average Rate for Wheeling Service for Scheduling Point q.

F 3.2 **P_n** **($/kWh)**

The applicable Wheeling Access Charge rate for TAC Area or Participating TO n in $/kWh as set forth in Section 7.1.4 of the ISO Tariff and Section 5 of the TO Tariff.

APPENDIX G

VOLTAGE SUPPORT and BLACK START CHARGES COMPUTATION

G 1 **Purpose of charge**

G 1.1 Voltage Support (VS) and Black Start (BS) charges are the charges made by the ISO to recover costs it incurs under contracts entered into between the ISO and those entities offering to provide VS or BS. Each Scheduling Coordinator pays an allocated proportion of the VS&BS charge to the ISO so that the ISO recovers the total costs incurred.

G 1.2 All Generating Units are required by the ISO Tariff to provide reactive power by operating within a power factor range of 0.90 lag and 0.95 lead. Additional short-term Voltage Support required by the ISO is referred to as supplemental reactive power. If the ISO requires the delivery of this supplemental reactive power by instructing a Generating Unit to operate outside its mandatory MVar range, the Scheduling Coordinator representing this Generating Unit will only receive compensation if it is necessary to reduce the MW output to achieve the MVar instructed output. Supplemental reactive power charges to Scheduling Coordinators are made on a Trading Interval basis. As of the ISO Operations Date the ISO will contract for long-term Voltage Support Service with the Owner of Reliability Must-Run Units under Reliability Must-Run Contracts.

G 1.3 The ISO will procure Black Start capability through contracts let on an annual basis. The quantities and locations of the Black Start capability will be determined by the ISO based on system analysis studies. Charges to Scheduling Coordinators for instructed Energy output from Black Start units are made on a Trading Interval basis.

G 2 **Fundamental formulae**

G 2.1 **Payments to Scheduling Coordinators for providing Voltage Support**

Payments to Scheduling Coordinators for additional Voltage Support service comprise:

G 2.1.1 **Lost Opportunity Cost Payments (supplemental reactive power) to Scheduling Coordinators for Generating Units**

When the ISO obtains additional Voltage Support by instructing a Generating Unit to operate outside its mandatory MVar range by reducing its MW output the ISO will select Generating Units based on their Supplemental Energy Bids ($/MWh). Subject to any locational requirements the ISO will select the Generating Unit with the highest decremental Supplemental Energy Bid to reduce MW output by such amount as is necessary to achieve the instructed MVar reactive energy production. Each Trading Interval the ISO will pay Scheduling Coordinator j for that Generating Unit i in Zone x, the lost opportunity cost ($) resulting from the reduction of MW output in Trading Interval t in accordance with the following formula:

$VSST_{xijt} = Max\ \{0, P_{xt} - Sup_{xdecit}\} * DEC_{xit}$

G 2.1.2 Long-term contract payments to Scheduling Coordinators for Reliability Must-Run Units for Generating Units and other Voltage Support Equipment

The ISO will pay Scheduling Coordinator j for the provision of Voltage Support from its Reliability Must-Run Units located in Zone x in month m a sum ($VSLT_{xjm}$) consisting of:

(a) the total of the Ancillary Service Pre-empted Dispatch Payments if the ISO has decreased the output of the Reliability Must-Run Units for the provision of Voltage Support outside the power factor range of the Reliability Must-Run Unit in any Trading Interval in month m and/or

(b) (if applicable) the total payments for the provision of Voltage Support in month m requested by the ISO from the synchronous condensers of the Reliability Must-Run Units,

calculated in each case in accordance with the terms of the relevant Reliability Must-Run Contract. Data on these payments will not be generated by the ISO. Such data will be based on the invoices issued by the Owners of Reliability Must-Run Generating Units pursuant to their Reliability Must-Run Contracts and will be verified by the ISO.

G 2.2 Charges to Scheduling Coordinators for Voltage Support

G 2.2.1 User Rate

The user rate ($/MWh) for the lost opportunity cost for Voltage Support referred to in G 2.1.1 in Zone x for Trading Interval t will be calculated using the following formula:

$$VSSTRate_{xt} = \frac{\sum_{ij} VSST_{xijt}}{\sum_{j} QChargeVS_{xjt}}$$

The user rate ($/MWh) for month m for long-term Voltage Support referred to in G 2.1.2 in Zone x will be calculated using the following formula:

$$VSSTRate_{xm} = \frac{\sum_{j} VSLT_{xjm}}{\sum_{jm} QChargeVS_{xjt}}$$

G 2.2.2 Voltage Support Charges

The lost opportunity cost Voltage Support charge ($) payable to recover the sums under G 2.1.1 for Zone x for Trading Interval t for Scheduling Coordinator j will be calculated using the following formula:

$$VSSTCharge_{xjt} = VSSTRate_{xt} * QChargeVS_{xjt}$$

The monthly long-term Voltage Support charge ($) payable to recover sums under G 2.1.2 for Zone x for month m for Scheduling Coordinator j will be calculated using the following formula:

$$VSLTCharge_{xjm} = VSLTRate_{xm} * \sum_{m} QChargeVS_{xjt}$$

G 2.3 Payments to Participating Generators for Black Start

Payments to Participating Generators that provide Black Start Energy or capability shall be made in accordance with the agreements they have entered into with the ISO for the provision of Black Start services and shall be calculated as follows:

G 2.3.1 Black Start Energy Payments

Whenever a Black Start Generating Unit provides a Black Start in accordance with the ISO's instructions, the ISO will pay the Black Start Generator for that Unit for the Generating Unit's energy output and start-up costs. The ISO will pay Black Start Generator for Generating Unit i, the Black Start energy and start-up costs ($) in Trading Interval t in accordance with the following formula:

$$BSEn_{ijt} = (EnQBS_{ijt} * EnBid_{ijt}) + BSSUP_{ijt}$$

G 2.3.2 Black Start Energy Payments to Owners of Reliability Must-Run Units

Whenever a Reliability Must-Run Unit provides a Black Start in accordance with the ISO's instructions, the ISO will pay the Scheduling Coordinator of the Reliability Must-Run Unit the Generating Unit's Energy and start-up costs. The ISO will pay Scheduling Coordinator j for Reliability Must-Run Unit i the Black Start Energy and start-up costs ($) in Trading Interval t in accordance with the following formula:

$$BSEn_{ijt} = (EnQBS_{ijt} * EnBid_{ijt}) + (BSSUP_{ijt})$$

G 2.4 Charges to Scheduling Coordinators for Black Start

G 2.4.1 User Rate

The user rate ($/MWh) for Black Start Energy payments referred to in G 2.3.1 and G 2.3.2 for Trading Interval t will be calculated using the following formula:

$$BSRate_{t} = \frac{\sum_{ij} BSEn_{ijt}}{\sum_{j} QChargeBlackStart_{jt}}$$

G 2.4.2 Black Start Charges

The user charge ($/MWh) for Black Start Energy to recover the costs of payments under G 2.3.1 and G 2.3.2 for Trading Interval t for Scheduling Coordinator j will be calculated using the following formula:

$$BSCharge_{jt} = BSRate_t * QChargeBlackStart_{jt}$$

G 3 Meaning of Terms in the Formulae

G 3.1 $VSST_{xijt}$ ($)

The lost opportunity cost paid by the ISO to Scheduling Coordinator j for Generating Unit i in Zone x, resulting from the reduction of MW output in Trading Interval t.

G 3.2 P_{xt} ($/MWh)

The Hourly Ex Post Price for Imbalance Energy in Trading Interval t in Zone x.

G 3.3 Sup_{xdecit} ($/MWh)

The Supplemental Energy Bid submitted by Scheduling Coordinator j for Generating Unit i in Zone x in Trading Interval t, whose output is reduced by the ISO to provide additional short-term Voltage Support.

G 3.4 Dec_{xit} (MW)

The reduction in MW by Scheduling Coordinator j for Generating Unit i in Zone x in Trading Interval t, in order to provide short-term additional Voltage Support.

G 3.5 $VSLT_{xjm}$ ($)

The payment from the ISO to Scheduling Coordinator j for its Reliability Must-Run Units in Zone x for Voltage Support in month m calculated in accordance with the relevant Reliability Must-Run Contract.

G 3.6 $VSSTRate_{xt}$ ($/MWh)

The Trading Interval lost opportunity cost Voltage Support user rate charged by the ISO to Scheduling Coordinators for Trading Interval t for Zone x.

G 3.7 $VSLTRate_{xm}$ ($/MWh)

The monthly long-term Voltage Support user rate charged by the ISO to Scheduling Coordinators for month m for Zone x.

G 3.8 $QChargeVS_{xjt}$ (MWh)

The charging quantity for Voltage Support for Scheduling Coordinator j for Trading Interval t in Zone x equal to the total metered Demand (including exports to neighboring Control Areas) for Scheduling Coordinator j in Zone x for Trading Interval t.

G 3.9 $VSSTCharge_{xjt}$ ($)

The lost opportunity cost Voltage Support user charge for Zone x for Trading Interval t for Scheduling Coordinator j.

G 3.10 $VSLTCharge_{xjm}$ ($)

The long-term charge for Voltage Support for month m for Zone x for Scheduling Coordinator j.

G 3.11 **$BSEn_{ijt}$** **($)**

The ISO payment to Scheduling Coordinator j (or Black Start Generator j) for that Generating Unit i providing Black Start Energy in Trading Interval t.

G 3.12 **$EnQBS_{ijt}$** **(MWh)**

The energy output, instructed by the ISO, from the Black Start capability of Generating Unit i from Scheduling Coordinator j (or Participating Generator j) for Trading Interval t.

G 3.13 **$EnBid_{ijt}$** **($/MWh)**

The price for Energy output from the Black Start capability of Generating Unit i of Scheduling Coordinator j or (Black Start Generator j) for Trading Interval t calculated in accordance with the applicable Reliability Must-Run Contract or Interim Black Start Agreement.

G 3.14 **$BSSUP_{ijt}$** **($)**

The start-up payment for a Black Start successfully made by Generating Unit i of Scheduling Coordinator j (or Black Start Generator j) in Trading Interval t calculated in accordance with the applicable Reliability Must-Run Contract or Interim Black Start Agreement.

G 3.15 **$BSRate_t$** **($/MWh)**

The Black Start Energy payment user rate charged by the ISO to Scheduling Coordinators for Trading Interval t.

G 3.16 **$QChargeBlackstart_{jt}$** **(MW)**

The charging quantity for Black Start for Scheduling Coordinator j for Trading Interval t equal to the total metered Demand (excluding exports to neighboring Control Areas) of Scheduling Coordinator j for Trading Interval t.

"Prior Period Change" means any correction, surcharge, credit, refund or other adjustment pertaining to a billing month which is discovered after the Revised Adjusted RMR Invoice for such billing month has been issued.

"Prior Period Change Worksheet" means a worksheet prepared by the RMR Owner and submitted to the ISO following discovery of a necessary change to an RMR invoice after the Revised Adjusted RMR Invoice for the billing month has been issued.

"Responsible Utility Facility Trust Account" means a segregated commercial bank account under the Facility Trust Account containing funds held in trust for the Responsible Utility.

"RMR Invoice" means any Estimated RMR Invoice, Revised Estimated RMR Invoice, Adjusted RMR Invoice, or Revised Adjusted RMR Invoice.

"RMR Owner Facility Trust Account" means a segregated commercial bank account under the Facility Trust Account containing funds held in trust for the RMR Owner.

"RMR Payment" means any amounts which the ISO is obligated to pay to RMR Owners under RMR Contracts, net of any applicable credits under RMR Contracts.

"RMR Payments Calendar" means the Payments Calendar issued by the ISO pursuant to Section 3 of this Annex 1.

"RMR Refund" means any amounts which RMR Owners are obligated to pay the ISO and the ISO is obligated to pay Responsible Utilities under RMR Contracts, or resulting from an order by the Federal Energy Regulatory Commission, for deposit into the Responsible Utility Facility Trust Account.

"RMR Security" means the form of security provided by a Responsible Utility to cover its liability under this Annex pursuant to Section 5.2.7.3 of the ISO Tariff.

1.2.4 Rules of Interpretation and Other Terms and Conventions

The rules of interpretation set out in SABP 1.2.3, and the provisions of SABP 1.2.4, 1.2.5 and 1.2.6 shall apply to this Annex.

1.3 Scope of Application to Parties

This Annex applies to the RMR Payments owed RMR Owners by the ISO, the RMR Charges owed by the Responsible Utilities to the ISO and the RMR Refunds owed to the ISO by RMR Owners and owed to

"Certificate of Compliance" means a certificate issued by the ISO which states that the Metering Facilities referred to in the certificate satisfy the certification criteria for Metering Facilities contained in the ISO Tariff and this Protocol.

"Check Meter" means a redundant revenue quality meter which is identical to and of equal accuracy to the primary revenue quality meter connected at the same metering point which must be certified in accordance with the ISO Tariff and this Protocol.

"Compatible Meter Data Server" means a meter data acquisition and processing system which is capable of passing Meter Data and/or Settlement Quality Meter Data to MDAS via File Transfer Protocol (FTP) and which has been certified in accordance with this Protocol by the ISO or its authorized representative.

"ISO Metered Entity Meter Service Agreements" means the meter service agreements between the ISO and ISO Metered Entities.

"Line Loss Correction Factor" means the line loss correction factor as set forth in the Technical Specifications.

"MDAS" means the ISO's revenue meter data acquisition and processing system.

"Meter Data Exchange Format" means the format for submitting Meter Data to the ISO which will be published by the ISO on the ISO Home Page or available on request to the Meter and Data Acquisition Manager, ISO Client Service Department.

"Meter Data Request Format" means the format for requesting Settlement Quality Meter Data from the ISO which will be published by the ISO on the ISO Home Page or available on request to the Meter and Data Acquisition Manager, ISO Client Service Department.

"Metering Facilities" means revenue quality meters, instrument transformers, secondary circuitry, secondary devices, meter data servers, related communication facilities and other related local equipment.

"MP Appendix" means an appendix to this Protocol.

"Proposal for Installation" means a written proposal submitted by an ISO Metered Entity to the ISO describing a proposal for the installation of additional Metering Facilities.

"SC" means Scheduling Coordinator.

"SC Meter Service Agreements" means the meter service agreements between the ISO and SCs.

"Technical Specifications" means Appendices B to G (inclusive) of this Protocol.

"Transformer Loss Correction Factor" means the transformer loss correction factor as set forth in the Technical Specifications to be applied to revenue quality meters of ISO Metered Entities which are installed on the low voltage side of step-up transformers.

MP 1.2.3 Rules of Interpretation

The following rules of interpretation and conventions have been adopted in this Protocol:

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

(e) Any reference to a day, week, month or year is a reference to a calendar day, week, month or year except that a reference to a Business Day shall mean a day on which the banks in California are open for business.

MP 1.3 Scope

MP 1.3.1 Scope of Application to Parties

This Protocol applies to the following entities:

(a) the ISO;

(b) ISO Metered Entities; and

(c) SCs in respect of the SC Metered Entities they represent.

If an ISO Metered Entity is also a SC, it shall be treated as an ISO Metered Entity for the purposes of this Protocol and Section 10 of the ISO Tariff. Such an ISO Metered Entity will not be required to enter into a SC Meter Service Agreement unless it represents any metered entities other than itself. A SC Meter Service Agreement entered into by an ISO Metered Entity shall only apply to those metered entities that the ISO Metered Entity represents; the SC Meter Service Agreement shall not apply to the ISO Metered Entity other than in its capacity as SC for those metered entities. If a SC Metered Entity is also a SC, it shall be treated as a SC for the purposes of this Protocol and Section 10 of the ISO Tariff and any references to entities that such a SC represents shall be deemed to include that SC itself.

MP 1.3.2 Scope of SC Responsibilities

SCs will be responsible:

(a) for ensuring that those SC Metered Entities that they represent and which are subject to the procedures and standards set forth in the ISO Tariff and this Protocol, comply with those procedures and standards; and

(b) for providing the ISO with Settlement Quality Meter Data in accordance with the ISO Tariff and this Protocol for those SC Metered Entities that they represent.

MP 2.2.5 Format for Data Requests

SCs may obtain Settlement Quality Meter Data relating to the ISO Metered Entities they represent by directly polling MDAS using the Meter Data Request Format. The ISO will use its best efforts to ensure that such data is made available to SCs within 5 Business Days of the relevant Trading Day.

MP 2.3 SC Metered Entities

MP 2.3.1 Method of Submitting Meter Data to ISO

SCs must submit Settlement Quality Meter Data for those SC Metered Entities they represent to MDAS when required to submit that data in order to meet the requirements of SABP and the ISO Payments Calendar.

MP 2.3.2 Interface with MDAS

SCs shall utilize a Compatible Meter Data Server to interface with MDAS via WEnet.

MP 2.3.3 Frequency of Submitting Data

SCs shall submit Settlement Quality Meter Data to the ISO when required to do so by the SABP and the ISO Payments Calendar. SCs must also submit Settlement Quality Meter Data on demand. The ISO will issue such demands using voice communications. If the ISO issues a demand for Settlement Quality Meter Data, the SC from which the ISO demands that data must submit it to the ISO within 4 hours of receiving the demand from the ISO.

MP 2.3.4 Format for Data Submission

SCs shall submit Settlement Quality Meter Data to MDAS for the SC Metered Entities they represent using the Meter Data Exchange Format. Subject to any exemption granted by the ISO under MP 13, SCs must ensure that Settlement Quality Meter Data submitted to the ISO is in intervals of:

(a) 5 minutes for Loads and Generators providing Ancillary Services and/or Supplemental Energy; and

(b) 1 hour for other SC Metered Entities.

Each SC shall submit Settlement Quality Meter Data for all of the SC Metered Entities that it schedules aggregated by:

(a) Demand Zone, Load group or bus for Demand;

(b) the relevant unit for Generation; or

(c) the Scheduling Point for imports and exports.

The Settlement Quality Meter Data submitted by SCs may be in either kWh or MWh values.

MP 3.3 SC Metered Entities

MP 3.3.1 Requirement to Certify

Subject to any exemption granted by the ISO under MP 13, the ISO will not accept Settlement Quality Meter Data relating to a SC Metered Entity unless it is produced by Metering Facilities that are certified in accordance with:

(a) the certification or similar criteria prescribed by the relevant Local Regulatory Authority; or

(b) if that Local Regulatory Authority has not prescribed any certification or similar criteria for Metering Facilities, the certification criteria prescribed by this Protocol and those Metering Facilities have a current Certificate of Compliance.

MP 3.3.2 SC to Ensure Certification

If the relevant Local Regulatory Authority has not prescribed any certification criteria for the Metering Facilities of a SC Metered Entity, the SC representing that SC Metered Entity must promptly notify the ISO in writing that no such criteria have been prescribed. That SC will then be responsible for ensuring that the SC Metered Entities it represents obtain and maintain Certificates of Compliance in respect of all of the Metering Facilities of those SC Metered Entities in accordance with MP 3.1. SCs must engage an ISO Authorized Inspector to perform the certification of any Metering Facilities that are to be certified under this Protocol or the ISO Tariff.

MP 3.3.3 Certification of Meter Data Servers

Subject to any exemption granted by the ISO under MP 13, the ISO will not accept Settlement Quality Meter Data relating to a SC Metered Entity from a meter data server unless that meter data server is a Compatible Meter Data Server.

MP 3.3.4 Confirmation of Certification

On the written request of the ISO, each SC must give the ISO written confirmation that the Metering Facilities of each SC Metered Entity that it represents are certified in accordance with either the criteria of the relevant Local Regulatory Authority or the criteria prescribed by this Protocol within 5 Business Days of receiving a request from the ISO.

MP 3.3.5 ISO's Request for Certificates

The ISO may require SCs to provide it with a copy of any certificate issued by a Local Regulatory Authority in respect of the Metering Facilities of each SC Metered Entity they represent. The SC must provide to the ISO a copy of such certificate within 5 Business Days of receiving the request for the certificate from the ISO.

MP 3.3.6 Deemed Certification

In accordance with Section 10.6.6.2 of the ISO Tariff, those revenue quality meters of SC Metered Entities that are subject to certification pursuant to this Protocol and the ISO Tariff and which were installed and operational as of the ISO Operations Date will be deemed to be certified for the purposes of the ISO Tariff and this Protocol. Revenue quality meters that have been fully installed as of the ISO Operations Date but which are not operational as of that date because they were undergoing maintenance or repairs will also be deemed to be certified in accordance with the ISO Tariff and this Protocol.

MP 4 AUDITING AND TESTING OF METERING FACILITIES

MP 4.1 ISO Metered Entities

MP 4.1.1 Requirement for Audits and Tests

Subject to any exemption granted by the ISO under MP 13, the Metering Facilities of ISO Metered Entities are subject to audit and testing by the ISO, or its authorized representative, in accordance with Section 10.5.1 of the ISO Tariff and this Protocol. The ISO will have the right to either conduct any audit or test it considers necessary or to witness such audit or test carried out by the ISO Metered Entity or an ISO Authorized Inspector engaged by the ISO Metered Entity or the ISO to carry out those audits or tests.

MP 4.1.2 Failure to Comply

The rights, powers, authorities and measures available to the ISO in respect of any failure by an ISO Metered Entity to comply with the ISO's audit or test procedures will be set forth in the ISO Metered Entity Meter Service Agreements.

MP 4.2 SC Metered Entities

MP 4.2.1 Requirement for Audit and Testing

(a) Audit and Testing by SC

Each SC shall at least annually conduct (or engage an independent, qualified entity to conduct) audits and tests of the Metering Facilities of the SC Metered Entities that it represents and the Meter Data provided to the SC in order to ensure compliance with all applicable requirements of any relevant Local Regulatory Authority. SCs shall undertake any other actions that are reasonable necessary to ensure the accuracy and integrity of the Settlement Quality Meter Data provided by them to the ISO.

(b) Audit and Testing by ISO

Subject to any applicable Local Regulatory Authority requirements, the Metering Facilities and data handling and processing procedures of SCs and SC Metered Entities are subject to audit and testing by the ISO or an ISO Authorized Inspector in accordance with Section

10.6.7.7 of the ISO Tariff and this Protocol. Subject to any applicable Local Regulatory Authority requirements, the ISO will have the right to either conduct any audit or test it considers necessary or to witness such audit or test carried out by the SC, SC Metered Entity or an ISO Authorized Inspector engaged by the SC, SC Metered Entity or the ISO to carry out those audits or tests.

MP 4.2.2 Failure to Comply

The rights and measures available to the ISO with respect to any failure by a SC or a SC Metered Entity to comply with any applicable audit or test procedures contained in the ISO Tariff and this Protocol, will be set forth in the SC Meter Service Agreements.

MP 5 INSTALLATION OF ADDITIONAL METERING FACILITIES

MP 5.1 ISO Requirement to Install Additional Metering

MP 5.1.1 ISO Authority to Require Additional Metering Facilities

The ISO has authority under Section 10.2.2 the ISO Tariff to require an ISO Metered Entity to install Metering Facilities in addition to those Metering Facilities on the ISO Controlled Grid at the ISO Operations Date. In directing the addition of meters and metering system components that would impose increased costs on an ISO Metered Entity, the ISO shall give due consideration to whether the expected benefits of such equipment are sufficient to justify such increased costs. An ISO Metered Entity may not commence installing those additional Metering Facilities until the ISO has approved its Proposal for Installation.

MP 5.1.2 Requirement to Install

If the ISO determines that there is a need to install additional Metering Facilities on the ISO Controlled Grid, it will notify the relevant ISO Metered Entity of that need. The ISO's notice to that ISO Metered Entity will include the following information:

(a) the location of the Meter Point at which the additional Metering Facilities are required;

(b) the date by which the ISO Metered Entity must install the relevant Metering Facilities;

(c) the reason for the need to install the additional metering Facilities; and

(d) any other information that the ISO considers relevant.

MP 5.1.3 Obligations of ISO Metered Entity

An ISO Metered Entity that is notified by the ISO that it is required to install additional Metering Facilities must:

(a) give the ISO written confirmation of receipt of that notice within 3 Business Days of receiving that notice;

(b) submit a Proposal for Installation to the ISO within 45 Business Days of receiving that notice. The Proposal for Installation must set out the following information:

(d) Confirmation of Satisfaction of Conditions

If the ISO determines that a condition in the approval of the Proposal for Installation has been satisfied, it will give the ISO Metered Entity written confirmation that the condition has been satisfied.

(e) Unsatisfied Conditions

If the ISO determines that a condition has not been satisfied after having received notice from an ISO Metered Entity pursuant to MP 5.1.6(c), the ISO will notify the ISO Metered Entity that it does not consider the condition satisfied and shall set out in that notice the reason(s) that it does not consider the condition satisfied. If, after using all reasonable good faith efforts, the ISO and the ISO Metered Entity are unable to agree on whether that condition is satisfied, either entity may refer the dispute to the ISO ADR Procedures.

MP 5.1.7 Rejection

If the ISO rejects a Proposal for Installation, it will promptly notify the ISO Metered Entity that the Proposal for Installation has been rejected and set out in that notice the reason for its rejection. The ISO Metered Entity must submit to the ISO a revised Proposal for Installation within 14 Business Days of receiving such notice of rejection. If the ISO rejects for a second time a Proposal for Installation submitted by an ISO Metered Entity in respect of the same or similar notice issued by the ISO under MP 5.1.2, the ISO and the ISO Metered Entity will use all reasonable good faith efforts to reach agreement on the requirements and disputed items and in the absence of agreement either entity may refer the dispute to the ISO ADR Procedures.

MP 5.2 ISO Metered Entities' Election to Install Additional Metering

In accordance with Section 10.2.2 of the ISO Tariff, an ISO Metered Entity may choose to install additional metering, including Check Meters. If an ISO Metered Entity installs such additional metering, such metering must, unless the ISO agrees otherwise:

(a) be installed and maintained at the ISO Metered Entity's cost;

(b) be located on the ISO Metered Entity's side of any primary meter; and

(c) not interfere with the accuracy of any primary meter and, if that primary meter is directly polled by the ISO, the ISO's ability to directly poll that meter.

Any Meter Data produced by any such additional metering may be used by the ISO for Settlement and billing purposes in the event of the failure, or during tests or repairs of, the primary meter provided that such additional metering has a current Certificate of Compliance, the ISO Metered Entity gives the ISO prior verbal notice that such meter will be used and the period for which it will be used and, if the primary meter is directly polled by the ISO, the additional metering must also be capable of being directly polled by the ISO.

MP 6 MAINTENANCE OF METERING FACILITIES

MP 6.1 ISO Metered Entities

MP 6.1.1 Duty to Maintain Metering Facilities

ISO Metered Entities must maintain their Metering Facilities so that those Metering Facilities continue to meet the standards prescribed by the ISO Tariff (including Appendix J) and this Protocol.

If the Metering Facilities of an ISO Metered Entity require maintenance in order to ensure that they operate in accordance with the requirements of the ISO Tariff and this Protocol, the ISO Metered Entity shall notify the ISO by telephone or other means specified by the ISO of the need for such maintenance. The ISO Metered Entity must also inform the ISO of the time period during which such maintenance is expected to occur. During that period, the ISO Metered Entity or its authorized representative shall be entitled to access those sealed Metering Facilities to which access is required in order to undertake the required maintenance.

During periods for which no Meter Data is available from a meter which has a current Certificate of Compliance, the ISO will substitute estimated meter data for that ISO Metered Entity using the estimation procedures referred to in MP 10.1. That estimated meter data will be used by the ISO in its Settlement and billing process.

MP 6.1.2 Repairs

If a revenue quality meter of an ISO Metered Entity requires repairs to ensure that it operates in accordance with the requirements of the ISO Tariff and this Protocol, the ISO Metered Entity must immediately notify the ISO of the need for repairing that meter and must ensure that those repairs are completed:

(a) where there is no Check Meter installed, within 12 hours of the notification to the ISO; or

(b) where there is a Check Meter installed, within 5 Business Days of the notification to the ISO.

During periods for which no Meter Data is available from a meter which has a current Certificate of Compliance, the ISO will substitute estimated meter data for that ISO Metered Entity using the estimation procedures referred to in MP 10.1. That estimated meter data will be used by the ISO in its Settlement and billing process.

In respect of Metering Facilities (other than a revenue quality meter) of an ISO Metered Entity that need repair, the ISO Metered Entity shall notify the ISO of that need and, after consultation with the ISO Metered Entity, the ISO will set the time period in which such repairs must be completed.

have been properly implemented. The ISO will not perform any validation, editing or estimating on the Settlement Quality Meter Data it receives from SCs.

MP 11 COMMUNICATIONS

MP 11.1 Facilities Provided by the ISO

The ISO will provide the facilities referred to in this MP 11.1 to acquire Meter Data from ISO Metered Entities and receive Settlement Quality Meter Data from SCs.

MP 11.1.1 MDAS Master Station

The MDAS master station will have a redundant configuration. The primary master station is located in Folsom, the redundant master station is located in Alhambra.

MP 11.1.2 WEnet

MDAS will use WEnet to acquire Meter Data from ISO Metered Entities and receive Settlement Quality Metered Data from SCs. WEnet is an ISO-provided Wide Area Network (WAN). WEnet will use the TCP/IP networking protocol.

MP 11.1.3 Points of Presence (POP)

WEnet will have a Point of Presence (POP) in the general vicinity of most ISO Metered Entities and SCs. The POP is the interface point between WEnet and the facilities provided by ISO Metered Entities and SCs pursuant to MP 11.2 and MP 11.3.

MP 11.1.4 Facilities Failure

In the event that the primary or redundant MDAS master station or WEnet fails, the procedures referred to in Appendix A will be followed by the ISO, ISO Metered Entities and SCs.

MP 11.2 Facilities Provided by ISO Metered Entities

ISO Metered Entities must provide the telecommunication facilities referred to in MP 11.2.1 to MP 11.2.3 inclusive to connect their Compatible Meter Data Servers to the WEnet POP.

MP 11.2.1 Telecommunications Channels

The ISO Metered Entity must provide one of the following types of telecommunication channels from the WEnet POP to its Compatible Meter Data Servers:

(a) Digital leased line;

(b) ISDN channel; or

(c) frame relay channel.

With the ISO's approval, the revenue quality meters of two or more ISO Metered Entities may be served by one telecommunications channel.

MP 11.2.2 Router/Terminal Server

ISO Metered Entities must provide router/terminal servers to interface the telecommunication channels to revenue quality meters. Each revenue quality meter will use an RS-232 interface nominally operating at 9600 bits/second.

MP 11.2.3 Meter Data Server

ISO Metered Entities must use a Compatible Meter Data Server to interface with MDAS.

MP 11.3 Facilities provided by SCs

SCs must use a Compatible Meter Data Server to interface with MDAS.

MP 12 METER IDENTIFICATION

MP 12.1 SC Metered Entities

If a SC Metered Entity is required to identify its revenue quality meters by the relevant:

(a) Local Regulatory Authority; or

(b) UDC,

then the SC representing that SC Metered Entity must, at the ISO's request, provide the ISO with a copy of that information within 5 Business Days of a request by the ISO in a format to be prescribed by the ISO.

If a SC Metered Entity is not required by either the relevant Local Regulatory Authority or UDC to identify its revenue quality meters, the SC representing that SC Metered Entity shall maintain an accurate record of the revenue quality meter of each of the SC Metered Entities that it represents from time to time. The record maintained by SCs must include the information set out in the Technical Specifications. The SC must, at the ISO's request, provide the ISO with a copy of any information contained in that record within 5 Business Days of a request by the ISO in a format to be prescribed by the ISO.

MP 13 EXEMPTIONS FROM COMPLIANCE

MP 13.1 Authority to Grant Exemptions

In addition to the specific exemptions granted under the ISO Tariff, the ISO has the authority under the ISO Tariff to grant exemptions from compliance with certain requirements imposed by the ISO Tariff and this Protocol.

MP 13.2 Guidelines for Granting Exemptions

The ISO will use the following guidelines when considering applications for exemptions from compliance with the ISO Tariff and this Protocol.

(a) Publication of Guidelines

The ISO will from time to time publish the general guidelines that it may use when considering applications for exemptions so as to achieve consistency in its reasoning and decision making and to give prospective applicants an indication of whether an application will be considered favorably.

(b) Publication of Exemption Applications

The ISO will promptly publish on the ISO Home Page a description of each application it receives for an exemption.

(c) Publication of Decision

The ISO will publish on the ISO Home Page details of whether the application was approved or rejected by it and, if the ISO considers it appropriate, the reasons for rejecting the application.

(d) Class Exemptions

In addition to exemptions granted to individual entities, the ISO may grant exemptions that will apply to a class of entities. The ISO may grant class exemptions whether or not it has received any application for an exemption. The ISO will publish details of the class exemptions it has granted on the ISO Home Page.

MP 13.3 Procedure for Applying for Exemptions

All applications to the ISO for exemptions from compliance with the requirements of the ISO Tariff or this Protocol must be made in writing addressed to the Meter and Data Acquisition Manager, Client Service Department. The ISO will confirm receipt of each application it receives within 3 Business Days of receiving the application. The ISO will decide whether to grant the exemption within 45 Business Days of receiving the application. At any time during that period, the ISO may require the applicant to provide additional information in support of its application. The applicant must provide such additional information to the ISO within 5 Business Days of receiving the request for additional information or within such other period as the ISO may notify to the applicant. If the ISO makes a request for additional information more than 40 Business Days after the date on which it received the

application, the ISO will have an additional 7 Business Days after receiving that additional information in which to consider the application. If the applicant does not provide the additional information requested, the ISO may refuse the application in which case it will notify the applicant that its application has been rejected for failure to provide the additional information.

MP 13.4 Information to be Included in the Application

The application submitted to the ISO must provide:

(a) a detailed description of the exemption sought (including specific reference to the relevant section(s) of the ISO Tariff and/or this Protocol giving the ISO authority to grant the exemption) and the facilities to which the exemption will apply;

(b) a detailed statement of the reason for seeking the exemption (including any supporting documentation);

(c) details of the entity(s) (if any) to which the exemption will apply;

(d) details of the location (if any) to which the exemption will apply;

(e) details of the period of time for which the exemption will apply (including the proposed start and finish dates of that period); and

(f) any other information requested by the ISO.

MP 13.5 Permitted Exemptions

MP 13.5.1 Exemptions from Providing Meter Data Directly to MDAS

(a) General

The ISO has the authority under Section 10.2.5 of the ISO Tariff to exempt ISO Metered Entities from the requirement to make Meter Data directly available to the ISO via MDAS.

In addition to the specific exemptions provided under MP 13.5.1(b), the ISO may, at its discretion, grant such an exemption where it considers the requirement to install communication links (or related facilities) between the ISO Metered Entity and WEnet to allow the ISO to directly poll that ISO Metered Entity would be unnecessary, impractical or uneconomic.

(b) Specific Exemptions Available

i. Tie Points

Meters located at tie points are exempted from the requirement that they be directly polled by the ISO provided that the meters at those tie points are revenue quality and they provide hourly, raw Meter Data to the ISO's Power Management System.

APPENDIX A

FAILURE OF ISO FACILITIES

A 1 WEnet Unavailable

A 1.1 Unavailable Functions of WEnet

During a total disruption of the WEnet the ISO will not be able to:

(a) communicate with ISO Metered Entities or SCs to acquire or provide any Meter Data or Settlement Quality Meter Data; and

(b) communicate general information.

A 1.2 Communications during WEnet Unavailability

During any period of WEnet unavailability, the ISO shall:

(a) make all reasonable efforts to provide general information to ISO Metered Entities and SCs using voice communications; and

(b) inform ISO Metered Entities and SCs of the methods they must use to provide Meter Data and Settlement Quality Meter Data to the ISO during that period.

A 2 Primary MDAS Master Station Completely Unavailable

A 2.1 Notification of Loss of Primary MDAS Master Station

In the event that the primary MDAS master station becomes completely unavailable, the ISO will use alternate communications to notify the redundant MDAS master station that the primary MDAS master station is unavailable. The ISO will post information on the situation on the WEnet. Additional voice notifications will be made as time permits.

A 2.2 Notification of Restoration of Primary MDAS Master Station

The ISO will post confirmation on WEnet that all computer systems are functioning normally (if such be the case) and use the redundant MDAS master station to take complete control of the all MDAS functions. Once the primary MDAS master station is again available, all functions will be transferred back to the primary MDAS master station and the ISO will notify all ISO Metered Entities and SCs via the WEnet.

APPENDIX G

ISO DATA VALIDATION, ESTIMATION AND EDITING PROCEDURES

This Appendix is provided for information purposes only, it gives an overview of the procedures that the ISO will use to validate, edit and estimate Meter Data received from ISO Metered Entities and, where an exemption applies, Meter Data received from SC Metered Entities.

G 1 Validation

G 1.1 Timing of Data Validation

Meter Data will be remotely retrieved via WEnet from ISO Metered Entities by MDAS on a daily basis. Validation will be performed on the new Meter Data as it is retrieved from the meter or Compatible Meter Data Server in order to detect:

- missing data;
- data that could be invalid based upon status information returned from the meter; or
- meter hardware or communication failure.

Additional validation will be performed on a daily basis to verify data against load patterns, check meters, schedules, MDAS load interval data and data obtained by SCADA.

G 1.2 Data Validation Conditions

MDAS will detect the following conditions so that erroneous data will not be used for Settlement or billing purposes:

G 1.2.1 Validation of metering/communications hardware:

- meter hardware/firmware failures;
- metering CT/VT failures (for example, losing one phase voltage input to the meter);
- communication errors;
- data which is recorded during meter tests;
- mismatches between the meter configuration and host system master files;
- meter changeouts (including changing CT/VT ratios);
- gaps in data;
- overflow of data within an interval;
- ROM/RAM errors reported by the meter; and
- alarms/phase errors reported by the meter.

ELIGIBLE INTERMITTENT RESOURCES PROTOCOL (EIRP)

EIRP 1 Objectives, Definitions and Scope

EIRP 1.1 Objectives

The objectives of this Protocol are to:

(a) Implement those sections of the ISO Tariff which involve Eligible Intermittent Resources and Participating Intermittent Resources;

(b) Describe the requirements for Eligible Intermittent Resources that intend to be certified as Participating intermittent Resources;

(c) Describe the ISO's responsibilities for certification, forecasting and performance monitoring of Participating Intermittent Resources; and

(d) Describe the responsibilities of Participating Intermittent Resources for operating and maintaining facilities, providing information in support of Energy forecasts, and scheduling Energy.

EIRP 1.2 Definitions

EIRP 1.2.1 Master Definitions Supplement

Unless the context otherwise requires, any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is a reference to a Section or an Appendix of the ISO Tariff. References to EIRP are to this Protocol or to the stated paragraph of this Protocol.

EIRP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meanings set opposite them:

"Forecast Fee" means the charge imposed on a Participating Intermittent Resource pursuant to the terms of this Protocol and ISO Tariff Appendix F, Schedule 4.

"Hour-Ahead Forecast" means the Energy forecast to be used by the Scheduling Coordinator representing a Participating Intermittent Resource for its Preferred Hour-Ahead Schedule, in accordance with EIRP 5.

EIRP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the date posted on the ISO Home Page.

(e) Time references in this Protocol are references to prevailing Pacific time.

EIRP 2.2.3 Equipment Installation

A Participating Intermittent Resource must install and maintain the communication equipment required pursuant to EIRP 3, and the equipment supporting forecast data required pursuant to EIRP 6.

EIRP 2.2.4 Forecast Model Validation

The ISO must determine that sufficient historic and real-time telemetered data are available to support an accurate and unbiased forecast of Energy generation by the Participating Intermittent Resource, according to the forecasting process validation criteria described in EIRP 4.

EIRP 2.3 Notice of Certification

When all requirements described in EIRP 2.2 have been fulfilled, the ISO shall notify the Scheduling Coordinator and the representatives of the Eligible Intermittent Resources comprising the Participating Intermittent Resource that the Participating Intermittent Resource has been certified, and is eligible for the settlement terms provided under Section 11.2.4.5 of the ISO Tariff, as conditioned by the terms of this EIRP.

EIRP 2.4 Requirements After Certification

EIRP 2.4.1 Forecast Fee

Beginning on the date first certified, a Participating Intermittent Resource must pay the Forecast Fee for all metered Energy generated by the Participating Intermitted Resource over the duration of the commitment indicated in the letter of intent described in EIRP 2.2.1(c).

The amount of the Forecast Fee shall be determined so as to recover the projected annual costs related to developing Energy forecasting systems, generating forecasts, validating forecasts, and monitoring forecast performance, that are incurred by the ISO as a direct result of participation by Participating Intermittent Resources in ISO Markets, divided by the projected annual Energy production by all Participating Intermittent Resources.

The initial rate for the Forecast Fee, and all subsequent rate changes as may be necessary from time to time to recover costs incurred by the ISO for the forecasting conducted on the behalf of Participating Intermittent Resources, shall be posted on the ISO Home Page. In no event shall the level of the Forecast Fee exceed the amount specified in ISO Tariff Appendix F, Schedule 4.

EIRP 2.4.2 Modification of Participating Intermittent Resource Composition

A Participating Intermittent Resource may seek to modify the composition of the Participating Intermittent Resource (e.g., by adding or eliminating an Eligible Intermittent Resource from the Participating Intermittent Resource). Such changes shall not be implemented without prior written approval by the ISO. The ISO will apply consistent criteria and expeditiously review any proposed changes in the composition of a Participating Intermittent Resource.

EIRP 2.4.3 Changes in Scheduling Coordinator

This EIRP does not impose any additional requirement for ISO approval to change the Scheduling Coordinator for an approved Participating Intermittent Resource than would otherwise apply under the ISO Tariff to changes in the Scheduling Coordinator representing a Generating Unit.

EIRP 2.4.4 Continuing Obligation

A Participating Intermittent Resource must meet all obligations established for Participating Intermittent Resources under the ISO Tariff and this EIRP, and must fully cooperate in providing all data and other information the ISO reasonably requests to fulfill its obligation to validate forecast models and explain deviations.

EIRP 2.4.5 Failure to Perform

If the ISO determines that a material deficiency has arisen in the Participating Intermittent Resource's fulfillment of its obligations under the ISO Tariff and this EIRP, and such Participating Intermittent Resource fails to promptly correct such deficiencies when notified by the ISO, then the eligibility of the Participating Intermittent Resource for the settlement accommodations provided in Section 11.2.4.5 of the ISO Tariff shall be suspended until such time that the unavailable data is provided or other material deficiency is corrected to the ISO's reasonable satisfaction. Such suspension shall not relieve the Scheduling Coordinator for the deficient Participating Intermittent Resource from paying the Forecast Fee over the duration of the period covered by the letter of intent described in EIRP 2.2.1(c).

EIRP 3 COMMUNICATIONS

EIRP 3.1 Forecast Data

The ISO may require various data relevant to forecasting Energy from the Participating Intermittent Resource to be telemetered to the ISO, including appropriate operational data, meteorological data or other data reasonably necessary to forecast Energy.

EIRP 3.2 Standards

The standards for communications shall be the monitoring and communications requirements for Generating Units providing only Energy and Supplemental Energy; as such standards may be amended from time to time, and published on the ISO Home Page.

EIRP 3.3 Cost Responsibility

An applicant for certification as a Participating Intermittent Resource is responsible for expenses associated with engineering, installation, operation and maintenance of required communication equipment.

EIRP 4 FORECASTING

The ISO is responsible for overseeing the development of tools or services to forecast Energy for Participating Intermittent Resources. The ISO will use its best efforts to develop accurate and unbiased forecasts, as limited by the availability of relevant explanatory data. Objective criteria and thresholds for unbiased, accurate forecasts shall be published on the ISO Home Page, and shall be used to certify Participating Intermittent Resources in accordance with EIRP 2.2.4.

EIRP 4.1 Hour-Ahead Forecast

The ISO shall develop expert, independent hourly forecasts of Energy generation on each Participating Intermittent Resource. A forecast shall be published each hour on the half hour for each of the next seven operating hours. Other forecasts, including a day-ahead forecast, may be developed at the ISO's discretion. The Scheduling Coordinator representing the Participating Intermittent Resource must use the Hour-Ahead Forecast that is available 30 minutes prior to the deadline for submitting the Preferred Hour-Ahead Schedule as specified in SP 3.3.1.

The ISO shall use best efforts to provide reliable and timely forecasts. However, if the ISO fails to deliver the Hour-Ahead Forecast to the Scheduling Coordinator prior to 15 minutes before the deadline for submitting Preferred Hour-Ahead Schedules, then the Hour-Ahead Forecast shall be the most recent Energy forecast provided by the ISO to the Scheduling Coordinator for the operating hour for which Preferred Schedules are next due.

EIRP 4.2 Forecast Calibration

The ISO shall calibrate the forecast to eliminate bias as measured by net MWh deviations across any and all relevant time periods to minimize the expected cumulative net charges or payments that are recovered or allocated through Section 11.2.4.5 of the ISO Tariff.

EIRP 4.3 Confidentiality

The ISO shall maintain the confidentiality of proprietary data for each Participating Intermittent Resource in accordance with Section 20.3 of the ISO Tariff.

EIRP 5 SCHEDULING AND SETTLEMENT

EIRP 5.1 Schedules

Scheduling Coordinators shall be required to submit Preferred Hour-Ahead Energy Schedules (MWh) for the Generating Units that comprise each Participating Intermittent Resource that are identical, in the aggregate, to the Hour-Ahead Forecast published for that Participating Intermittent Resource (MWh).

EIRP 5.2 Settlement

After a Participating Intermittent Resource is certified, settlement shall be determined for each Settlement Period based on consistency of Schedules and bids submitted on behalf of such Participating Intermittent Resources with the rules specified in the ISO Tariff and this Protocol.

No Supplemental Energy bids or Adjustment Bids may be submitted on behalf of a Participating Intermittent Resource. Submitting such bids shall render the Participating Intermittent Resource ineligible for settlement according to Section 11.2.4.5 of the ISO Tariff for that Settlement Period. Such activity will be monitored in accordance with EIRP 7.

EIRP 6 DATA COLLECTION FACILITIES

The Participating Intermittent Resource must install and maintain equipment to collect, record and transmit data that the ISO reasonably determines is necessary to develop and support a forecast model that meets the requirements of EIRP 4.

EIRP 6.1 Wind Resources

A Participating Intermittent Resource powered by wind must install at least one meteorological tower at a project location that is representative of the microclimate within the project boundary.

The meteorological tower must rely on equipment typically used in the wind industry to continuously monitor weather conditions at a wind resource site. Data collected shall be consistent with requirements published on the ISO Home Page. Such data must be gathered and telemetered to the ISO in accordance with EIRP 3.

If objective standards developed by the ISO indicate that the meteorological data may not be sufficiently representative of conditions affecting Energy output or changes in Energy output by that Participating Intermittent Resource, then the ISO may require that

hydroelectric units operating on a common watershed (but having multiple different interconnection points), or geothermal units fed from a common geothermal steam supply.

UAP 2 SUBMITTAL OF A REQUEST FOR UDP AGGREGATION

Requests for UDP Aggregation are submitted to the ISO and must include the following documentation:

(1) A completed UDP Aggregation Request form, which is available for downloading on the ISO website;

(2) A simplified electrical one-line diagram, which illustrates each resource, the connection of the resources to each other and to the ISO Control Area Grid;

(3) For Custom UDP Aggregations, a detailed description that explains physical operating interrelationships between the units, or, if there are no interrelationships, how the units are compatible and why an aggregation of these units for the purpose of calculating Uninstructed Deviation Penalties is reasonable.

UAP 3 ISO REVIEW OF A UDP AGGREGATION REQUEST

Upon receipt of a completed request form and accompanying attachments, the ISO shall review the request according to the criteria outlined herein. For Basic UDP Aggregations, the ISO shall undertake its best efforts to review and approve or reject it within three weeks of receipt. Review of a request for a Custom UDP Aggregation may take longer in some cases, depending on the complexity of the proposed aggregation. If the ISO anticipates that it will take more than three weeks to process a request, the ISO shall inform the entity requesting the UDP Aggregation of the estimated processing time for the request.

UAP 3.1 Criteria for Reviewing a Request

UAP 3.1.1 Scheduling Coordinator and Interconnection Point

Uninstructed Deviations may be aggregated for resources that are:

(1) Represented by the same Scheduling Coordinator and

(2) Connected to the same ISO Controlled Grid bus and voltage level.

The ISO will consider, on a case-by-case basis, requests to aggregate Uninstructed Deviations among resources represented by the same Scheduling Coordinator but not sharing a common ISO Controlled Grid bus and voltage level. In particular, the ISO will consider whether the request concerns resources

related by a common flow of fuel which cannot be interrupted without a substantial loss of efficiency of the combined output of all components; whether the Energy production from one resource necessarily causes Energy production from other resource(s); and whether the operational arrangement of resources determines the overall physical efficiency of the combined output of all of the resources.

UAP 3.1.2 Additional Criteria

Additional eligibility criteria for a UDP Aggregation are as follows:

(1) Only Generating Units shall be eligible for UDP Aggregation. As a general rule, pump-generating Units (or a Physical Scheduling Plant [PSP] containing a pump-generating Unit) cannot be part of a UDP Aggregation. However, it is possible that generating Units could form a UDP Aggregation comprised entirely of pump-generating Units whose operation is uniform, that is, Units all operating in either Generation mode or all in pump mode, but never mixed.

(2) UDP Aggregations cannot include any of the following:

(a) Load;
(b) Condition 2 Reliability Must Run (RMR) Units;
(c) Participating Intermittent Resources;
(d) Generating Units less than 5 MW; or
(e) Generating Units that span active or inactive Congestion Zones.

(3) The resources must have ISO direct telemetry and must be fully compliant with the ISO's direct telemetry standards.

(4) The Generating Units must exhibit the same effectiveness factors (factors within +/-10%) for managing inter- and -intra-zonal Constraints, under "normal/all elements in service" conditions, as well as during most local transmission outages.

(5) Custom UDP Aggregations involving units not directly connecting to the ISO Controlled Grid must recognize the transfer limits and status of the intermediate local facilities.

UAP 3.1.3 Approval of a Request

If a UDP Aggregation request is approved, the ISO shall create a new unique Resource ID, which reflects the identity or location of the units and stipulates the UDP Aggregation, but which cannot be used for scheduling purposes. The ISO shall inform the Scheduling Coordinator of the approval and ask the Scheduling Coordinator to confirm the desired start date of the UDP Aggregation. When that

ATTACHMENT D

NOTICE OF FILING SUITABLE FOR PUBLICATION IN THE FEDERAL REGISTER

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	)	**Docket No. ER04-1046-___**

Notice of Filing

[ ]

Take notice that on March 11, 2004, the California Independent System Operator Corporation (ISO) submitted a filing in compliance with the Commission's "Order on Proposed Tariff Amendment No. 54," issued in the above-captioned docket on October 22, 2003, 105 FERC ¶ 61,091. The ISO has served copies of this filing upon all entities that are on the official service list for the docket.

Any person desiring to intervene or to protest this filing should file with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. Any person wishing to become a party must file a motion to intervene. All such motions or protests should be filed on or before the comment date, and, to the extent applicable, must be served on the applicant and on any other person designated on the official service list. This filing is available for review at http://www.ferc.gov, using the eLibrary (FERRIS) link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, please contact FERC Online Support at FERCOnlineSupport@ferc.gov or toll-free at (866) 208-3676, or for TTY, contact (202) 502-8659. Protests and interventions may be filed electronically via the Internet in lieu of paper; see 18 C.F.R. § 385.2001(a)(1)(iii) and the instructions on the Commission's web site under the "e-Filing" link. The Commission strongly encourages electronic filings.

Comment Date: _____