FERC
RELIABILITY MUST-RUN SCHEDULES

Schedule A

Unit Characteristics, Limitations and Owner Commitments

1. Description of Facility

Provide the following information for all units at the Facility, regardless of their RMR designation status. Information regarding units not designated as Reliability Must-Run Units is required only if and to the extent that the information is used to allocate Facility costs between Reliability Must-Run Units and other units.

Unit	RMR (Y/N)	Maximum Net Dependable Capacity (includes ISO-paid Upgrade capacity)*	Fuel Type

For this Facility, the Owner will use ________ [insert either MW, MWhs, or service hours] in Schedule B to allocate Annual Fixed Revenue Requirements to and among Units. This election shall be applicable to all Facilities containing Reliability Must Run Units subject to any "RMR contract" as defined in the ISO Tariff executed by Owner or any of its affiliates as defined in 18 CFR § 161.2.

* Maximum Net Dependable Capacity shall reflect any transformer or line loss to the Delivery Point.

2. Description of RMR Units

Provide the address(es) of the Units at the Facility and the following tabular information:

	Unit	Unit	Unit
Type (fossil, combustion turbine, etc.)			
Synchronous Condenser Capability (Y/N)			
Power Factor Range (lead to lag)			
Maximum Reactive Power Leading, MVar			
Maximum Reactive Power Lagging, MVar			
Load at Maximum MVar Lagging, MW			
Load at Maximum MVar Leading, MW			
Black Start Capable (Y/N)			
Automatic Start or Ramp (Y/N)*			
Upgrade Capacity Paid by ISO ,MW			

* <u>If "Y", describe the conditions under which the Unit will start or ramp automatically</u>.

3. Operational and Regulatory Limitations of RMR Units:

Air Emissions Limitations
List applicable NO_x, CO, SO_2, particulate, and other appropriate emissions limits; note the name and address of the lead agency; the agency's applicable rule number(s); and note those pollutants for which an emissions cap applies.

Monthly Reserved MWh for Air Emission Limitations

Operating Limits related to Ambient Temperatures

Ambient Temperature Correction Factors for Availability Test

Provide a curve or table showing the Ambient Temperature Correction Factors for each Unit (the relationship between Ambient Temperature and Maximum Net Dependable Capability).

FERC License Conditions (hydroelectric Units)

Other Limits (e.g., cooling water discharge)

4. Delivery Point

Unit	Transmission Node (Station Name)	Voltage

5. Metering and Related Arrangements

Unit	Meter Location	Meter (Manufacturer & Model No.)

6. Start-up Lead Times

Non-hydroelectric Units

Unit	Time from notification to synchronization for a Unit that has been off line more than _____ hours*	Time from notification to synchronization for a Unit that has been off line more than __ hours but less than ___ hours	Time from notification to synchronization for a Unit that has been off line __ hours or less

"X_{max}" used in Schedules C and D shall be equal to or less than the hours in the heading of this column.

Hydroelectric Start-up Lead Times

Unit	Time from notification to synchronization - Normal Work hours	Time from notification to synchronization - Outside Normal Work hours

7. Ramping Constraint

Describe any constraints the Unit incurs between synchronization and release for full operation.

8. Ramp Rate

Unit	Manual Ramp Rate (normal)	AGC Ramp Rate

Separate Ramp Rates will be shown for each load range and will describe any special restrictions affecting Ramp Rates at various load points, e.g., feed pumps.

9. Minimum Load

Unit	Manual (MW)	AGC (MW)

10. Minimum Run Time

Unit	Hours

11. Minimum Off Time

Unit	Hours

12. Contract Service Limits

Unit	Maximum Annual MWh	Maximum Annual Service Hrs	Maximum Annual Start-ups

Maximum Monthly MWh (Hydroelectric Units only)

MWh

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

13. Owner's Repair Cost Obligation

Owner's Repair Cost Obligation for the current Contract Year is $_____.

14. Existing Contractual Limitations and Other Contract Restrictions on Market Transactions

15. Applicable UDC Tariff(s)

[List each Tariff and schedule to which it applies]

Schedule B

Monthly Option Payment

The formulas and values used to compute the Monthly Option Payment in accordance with Section 8.1 and Section 8.2 for each Unit for each Month are set forth in Equation B-1 below:

Equation B-1

$$\text{Monthly Option Payment} = \text{Monthly Availability Payment} + \text{Monthly Surcharge Payment} - \text{Monthly Nonperformance Penalty}$$

The Monthly Option Payment can never be less than zero.

1. The Monthly Availability Payment is calculated in accordance with Equation B-2 below:

Equation B-2

$$\text{Monthly Availability Payment (\$)} = \text{lesser of} \quad \text{Current Monthly Availability Payment (\$)} \quad \text{or} \quad \text{100\% of AFRR minus Cumulative Monthly Availability Payments Excluding Current Monthly Availability Payment (\$)}$$

2. The Current Monthly Availability Payment is calculated in accordance with Equation B-3 below:

Equation B-3

$$\text{Current Monthly Availability Payment (\$)} = \sum_{\text{for all hours}} \left[\text{Hourly Availability Charge (\$/hr)} \times \frac{\text{Unit Availability Limit (MW)}}{\text{Maximum Net Dependable Capacity (MW)}} \right]$$

Where:

A. Hourly Availability Charge is calculated in accordance with Equation B-4 below:

Equation B-4

$$\text{Hourly Availability Charge} = \text{Hourly Availability Rate} \times \text{Fixed Option Payment Factor}$$

Where:

- Hourly Availability Rate is calculated in accordance with Equation B-5 below.

Equation B-5

$$\text{Hourly Availability Rate} = \frac{\text{Annual Fixed Revenue Requirement}}{\text{Target Available Hours}}$$

Annual Fixed Revenue Requirement is set forth in Section 7 below.

Target Available Hours are set forth in Section 6 below.

- For Units under Condition 1, the Fixed Option Payment Factor is set forth in Table B-0 below:

Table B-0

Unit	Fixed Option Payment Factor

For Units under Condition 2, the Fixed Option Payment Factor is 1.

The Hourly Availability Charges for the Contract Year are set forth in Table B-1 below:

Table B-1

	Condition 1	Condition 2
Unit 1		
Unit 2		

B. Unit Availability Limit is defined in Article 1 of the Agreement.

C. Maximum Net Dependable Capacity is shown in Section 1 of Schedule A.

3. The Monthly Surcharge Payment is calculated in accordance with Equation B-6 below:

Equation B-6

$$\text{Monthly Surcharge Payment (\$)} = \text{lesser of} \quad \text{Current Monthly Surcharge Payment (\$)} \quad \text{or} \quad \text{100\% of Sum of all Annual Capital Item Costs minus Cumulative Monthly Surcharge Payments Excluding Current Monthly Surcharge Payment (\$)}$$

4. The Current Monthly Surcharge Payment is calculated in accordance with Equation B-7 below:

Equation B-7

$$\begin{matrix}\text{Current Monthly} \\ \text{Surcharge} \\ \text{Payment} \\ (\$)\end{matrix} = \begin{matrix}\text{Sum} \\ \text{for} \\ \text{all} \\ \text{hours}\end{matrix} \left[\begin{matrix}\text{Sum of all} \\ \text{Hourly Capital} \\ \text{Item Charges} \\ (\$/\text{hr})\end{matrix} \times \frac{\text{Unit Availability Limit (MW)}}{\text{Maximum Net Dependable Capacity (MW)}} \right]$$

Where:

A. The Hourly Capital Item Charge for each Capital Item approved pursuant to Sections 7.4 or 7.6 is calculated in accordance with Equation B-8 below:

Equation B-8

$$\begin{matrix}\text{Hourly Capital} \\ \text{Item Charge}\end{matrix} = \begin{matrix}\text{Hourly Capital} \\ \text{Item Rate}\end{matrix} \times \begin{matrix}\text{Surcharge} \\ \text{Payment Factor}\end{matrix}$$

Where:

· Hourly Capital Item Rate is calculated in accordance with Equation B-9 below:

Equation B-9

$$\begin{matrix}\text{Hourly} \\ \text{Capital Item} \\ \text{Rate}\end{matrix} = \frac{\text{Annual Capital Item Cost}}{\text{Target Available Hours}}$$

· Annual Capital Item Cost is the amount recoverable by Owner under this Agreement in a Contract Year for each Capital Item approved pursuant to Section 7.4 or Section 7.6.

· Target Available Hours are shown in Section 6 below.

· For Units under Condition 1, the Surcharge Payment Factor for all Capital Items covered by the Small Project Budget shall be the Fixed Option Payment Factor. For all other Capital Items, the Surcharge Payment Factor shall be as agreed to by Owner and ISO. If the Owner and ISO do not agree on the Surcharge Payment Factor, the Surcharge Payment Factor shall equal the Fixed Option Payment Factor, unless the Owner demonstrates in ADR that it would not have installed the proposed Capital Item in accordance with Good Industry Practice but for its obligations to the ISO under this Agreement, in which case the Surcharge Payment Factor shall be as determined in ADR.

· For Units under Condition 2, the Surcharge Payment Factor is 1.

The Hourly Capital Item Charges for the Contract Year are set forth in Table B-2 below:

Table B-2

Unit	Capital Item Project No.	Annual Capital Item Cost	Condition 1 Surcharge Payment Factor	Condition 1 Hourly Capital Item Charge	Condition 2 Hourly Capital Item Charge

B. Unit Availability Limit is defined in Article 1 of the Agreement.

C. Maximum Net Dependable Capacity is shown in Section 1 of Schedule A.

5. The Monthly Nonperformance Penalty is calculated pursuant to Section 8.5 using the following variables:

A. Hourly Penalty Rate

A Unit's Hourly Penalty Rate for each Contract Year is the lesser of (a) the Unit's Hourly Availability Rate for the Contract Year (calculated pursuant to Item 2.A above), or (b) three times the Unit's Hourly Availability Charge for the Contract Year (as shown in Table B-1 above).

The Hourly Penalty Rates for the Contract Year are set forth in Table B-3 below:

Table B-3

	Condition 1	Condition 2
Unit 1		
Unit 2		

B. Hourly Surcharge Penalty Rate

A Unit's Hourly Surcharge Penalty Rate for each Capital Item for each Contract Year is the lesser of (a) the corresponding Hourly Capital Item Rate for the Contract Year (calculated pursuant to Item 4.A above), or (b) three times the applicable Hourly Capital Item Charge for the Contract Year (as shown in Table B-2 above). The Hourly Surcharge Penalty Rates for the Contract Year are set forth in Table B-4 below:

Table B-4

Unit	Capital Item Project No.	Hourly Capital Item Rate	Condition 1 Hourly Surcharge Penalty Rate	Condition 2 Hourly Surcharge Penalty Rate

6. Target Available Hours

A Unit's Target Available Hours for each Contract Year are calculated in accordance with the Equation B-10 below:

Equation B-10

Target Available Hours (TAH) = Hours in the Calendar Year – (Average Other Outage Hours + Long-Term Planned Outage Hours)

Average Other Outage Hours means the average annual Other Outage Hours for the Unit during the 60-month period ending June 30 of the previous calendar year.

Long-term Planned Outage Hours means the Long-term Planned Outage Hours for the Contract Year scheduled with ISO pursuant to Section 7.2(a). For periods prior to December 31, 1998, Other Outage Hours shall exclude a planned interruption, in whole or in part, in the electrical output of a Unit to permit Owner to perform a major equipment overhaul or inspection or for new construction work, but only if the outage lasted 21 or more consecutive days.

Long-term Planned Outage Hours scheduled for a Contract Year shall be subject to the Long-term Scheduled Outage Adjustment pursuant to Section 8.6 of the Agreement.

The Average Other Outage Hours, Long-term Planned Outage Hours and Target Available Hours for each Unit for the Contract Year are shown in Table B-5 below:

Table B-5

Unit	Average Other Outage Hours	Long-term Planned Outage Hours	TAH

For the purposes of calculating Target Available Hours for the Contract Year ending December 31, 1999, (a) Average Other Outage Hours shall be calculated using the average annual Other Outage Hours for the Unit during the 60-month period ending December 31, 1998, and (b) Long-term Planned Outage Hours shall be calculated using the hours scheduled for performing Long-term Planned Outages as if the Agreement had become effective on January 1, 1999.

7. Annual Fixed Revenue Requirement (AFRR)

The Annual Fixed Revenue Requirement for each Unit is set forth in Table B-6 below. For any Contract Year commencing on or after January 1, 2002, the Annual Fixed Revenue Requirement shall be determined by the Formula Rate set forth in Schedule F, unless Owner files a superseding rate schedule under Section 205 of the Federal Power Act.

Table B-6

Unit	Annual Fixed Revenue Requirement

8. Limited Section 205 Filing for an Extension of Contract Term

If ISO has extended the term of this Agreement pursuant to Section 2.1(b), then not later than October 31 of the expiring Contract Year, Owner shall make a filing with FERC under Section 205 of the Federal Power Act containing the values in Tables B-1 through B-6 for the ensuing Contract Year.

In the event that a Long-term Planned Outage that is scheduled for the last quarter of the expiring Contract Year is postponed or rescheduled after October 31 of such year to the ensuing Contract Year, Owner shall make an additional Section 205 filing to revise the values in Tables B-1 through B-5 to reflect such rescheduled Long-term Planned Outage Hours.

SCHEDULE C

Variable Cost Payment
Part 1 for Thermal Units

The Variable Cost Payment for each Unit for the Billing Month shall be the amount calculated in accordance with the following formula:

Variable Cost Payment =
A. ISO Unit Monthly Billed Fuel Cost +
B. ISO Unit Monthly Fuel Imbalance Charge +
C. ISO Monthly Other Fuel Related Cost +
D. ISO Monthly Emissions Cost +
E. ISO Monthly Variable O&M Cost +
F. ISO Scheduling Coordinator Charge +
G ISO ACA Charge
.

Each component of the Variable Cost Payment for thermal Units will be calculated as described below:

A. <u>ISO Unit Monthly Billed Fuel Cost</u>

The ISO Unit Monthly Billed Fuel Cost is calculated in accordance with Equation C1-0.

Equation C1-0

$$\left(\begin{array}{c}\text{ISO Unit}\\ \text{Monthly Billed}\\ \text{Fuel Cost (\$)}\end{array}\right) = \frac{\begin{array}{c}\text{Monthly sum of the}\\ \text{ISO Unit Hourly Cap Heat Input}\\ \text{for this Unit}\\ \text{(MMBtu)}\end{array}}{\begin{array}{c}\text{Monthly sum of the ISO}\\ \text{Unit Hourly Cap Heat Input}\\ \text{for all Units at the Facility}\\ \text{(MMBtu)}\end{array}} \times \left(\begin{array}{c}\text{ISO Facility}\\ \text{Monthly Billed}\\ \text{Fuel Cost}\end{array}\right)$$

Where:

- ISO Unit Hourly Cap Heat Input for each Unit is calculated in accordance with Equation C1-6;
- The ISO Facility Monthly Billed Fuel Cost is calculated in accordance with Equation C1-1.

1. <u>The ISO Facility Monthly Billed Fuel Cost</u>

The ISO Facility Monthly Billed Fuel Cost is calculated in accordance with Equation C1-1.

Equation C1-1

$$\left(\begin{array}{c}\text{ISO Facility}\\ \text{Monthly}\end{array}\right. \qquad \left(\begin{array}{c}\text{ISO Facility}\\ \text{Cumulative}\end{array} \quad \begin{array}{c}\text{ISO Facility}\\ \text{Cumulative}\end{array}\right. \quad \left(\begin{array}{c}\text{ISO Facility}\\ \text{Cumulative}\end{array}\right.$$

$$\left[\begin{array}{c}\text{Billed}\\\text{Fuel Cost}\\(\$)\end{array}\right] = \text{Lesser of}\left[\begin{array}{c}\text{Actual}\\\text{Fuel Cost}\\(\$)\end{array}\text{ or }\begin{array}{c}\text{Cap}\\\text{Fuel Cost}\\(\$)\end{array}\right] - \left[\begin{array}{c}\text{Billed}\\\text{Fuel Cost}\\(\$)\end{array}\right]$$

Where:

- The ISO Facility Cumulative Actual Fuel Cost is the sum of all ISO Unit Monthly Actual Fuel Costs for all Units at the Facility since the start of the Contract Year, <u>including</u> the current Month. ISO Unit Monthly Actual Fuel Costs for each Unit is calculated in accordance with Equation C1-2.

- The ISO Facility Cumulative Cap Fuel Cost is the sum of all ISO Unit Monthly Cap Fuel Costs for all Units at the Facility since the start of the Contract Year, <u>including</u> the current Month. ISO Unit Monthly Cap Fuel Costs is the sum of the ISO Unit Hourly Cap Fuel Cost (calculated pursuant to Equation C1-5) for each hour of the Month for each Unit.

- The ISO Facility Cumulative Billed Fuel Cost is the sum of all ISO Unit Monthly Billed Fuel Costs for all Units at the Facility since the start of the Contract Year, <u>excluding</u> the current Month. ISO Unit Monthly Billed Fuel Cost for each Unit is calculated in accordance with Equation C1-0.

2. <u>ISO Unit Monthly Actual Fuel Cost</u>

The ISO Unit Monthly Actual Fuel Cost is calculated in accordance with Equation C1-2.

Equation C1-2

$$\left[\begin{array}{c}\text{ISO Unit}\\\text{Monthly}\\\text{Actual}\\\text{Fuel Cost}\\(\$)\end{array}\right] = \frac{\begin{array}{c}\text{Monthly sum of the ISO}\\\text{Unit Hourly Cap Heat Input}\\\text{for the Unit}\\\text{(MMBtu)}\end{array}}{\begin{array}{c}\text{Monthly sum of the}\\\text{Unit Hourly Cap Heat Inputs}\\\text{for all units at the Facility}\\\text{metered by the Fuel Meter}\\\text{(MMBtu)}\end{array}} \times \left[\left[\begin{array}{c}\text{Monthly}\\\text{Metered}\\\text{Fuel}\\\text{(MMBtu)}\end{array}\right] \times \begin{array}{c}\text{ISO}\\\text{Monthly}\\\text{Fuel}\\\text{Price}\\(\$/\text{MMBtu})\end{array} - \left[\begin{array}{c}\text{Monthly}\\\text{Start-up}\\\text{Fuel Cost}\\(\$)\end{array}\right]\right]$$

Where:

- ISO Unit Hourly Cap Heat Input is calculated in accordance with Equation C1-6.

- Unit Hourly Cap Heat Input is calculated in accordance with either Equation C1-7a or C1-7b.

- Monthly Metered Fuel is the non-duplicative sum of the quantities of fuel for the Month as measured by all gas metering systems or fuel oil measuring systems, as applicable (“Fuel Meters”), for the Unit.

  (a) If the fuel is natural gas, the Owner may select from one of three options for the Fuel Meter:

(i) the revenue meter used by the entity providing natural gas to measure gas delivered to one or more Units ("Fuel Custody Meter");

(ii) a gas metering system installed at the Facility to measure gas used in one or more Units that meets the measurement accuracy standard in the tariff of the local gas distribution company in whose service area the Facility is located and the measurement accuracy standards set forth below, and is subject to an annual accuracy test performed under the ISO's direction, as described below; or

(iii) a gas metering system installed at the Facility by the local gas distribution company in whose service area the Facility is located and maintained by the local gas distribution company to the same standards as revenue meters of the local gas distribution company.

For the selected Fuel Meter option, the Owner shall provide the required information for all Units, both RMR and non-RMR, connected to the specific Fuel Custody Meter.

If the Owner selects option (ii), the Owner shall assure the overall accuracy of the gas metering systems[1] in use for the Units are within acceptable industry and regulatory standards.[2] Gas metering systems shall be designed, installed, calibrated and maintained according to standards set forth by the American Gas Association (AGA), the American National Standards Institute (ANSI) and the California Public Utilities Commission (CPUC). An audit trail of all calibration records and measurement parameters used in volume and heating-value calculations as recorded electronically by the flow computer shall be maintained and all data shall be in no-longer-than-hourly intervals. All equations and calculations performed by the flow computer may be reviewed for accuracy and completeness, including compressibility, volumetric flow and energy flow, by the ISO or its

[1] The gas metering system includes the primary measurement element (orifice, turbine meter, etc.); secondary elements such as pressure, temperature and heating-value measurement devices; the gas chromatograph, the flow computer or other data-collection and storage device; and the communication or output system.

[2] The American Gas Association (AGA) and the American National Standards Institute (ANSI) publish industry standards that gas utilities and gas transportation companies use for gas metering. Applicable standards include: AGA Report No. 3, Orifice Metering of Natural Gas; AGA Report No. 7, Measurement of Gas by Turbine Meters, AGA Report No. 8, Compressibility Factors of Natural Gas; AGA Report No. 9, Measurement of Gas by Multipath Ultrasonic Meters; ANSI B109.2, Diaphragm Type Gas Displacement Meters; and ANSI B109.3 Rotary Type Gas Displacement Meters. Also, CPUC General Order 58-A requires customer meters to register accurately to within –2% to 1%.

agent. A consistent base pressure (14.73 psi) and base temperature (60? F) shall be used at all times. If the Facility has multiple sources of fuel gas, a gas chromatograph ("GC") shall be installed which analyzes all constituents of the blended gas, with the sampling point downstream of the individual supplies such that proper mixing occurs prior to sampling. The GC speed loop shall permit analysis of the gas in "real time".

In order to ensure the accuracy of a gas metering system selected under option (ii), an initial acceptance test shall be conducted by Owner and shall be witnessed by the ISO or its agent to assure the installation meets applicable industry standards. Such a test shall be conducted at five load points (maximum load, minimum load, and three evenly spaced load points), under steady state conditions (i.e., off Automatic Generation Control), and for a minimum of one hour at each load point. Analysis of the test results shall consist of a side-by-side comparison of volumetric flow, energy flow, gas-specific gravity and mole percents, and other factors mutually agreed to by the ISO and Owner for the Fuel Custody Meter and the meter installed at the Facility under option (ii). The gas metering system installed under option (ii) shall be deemed acceptable if the side-by-side energy flow comparison for the period shall be within +1 percent to –2 percent. The gas-metering system shall meet the required accuracy throughout the entire operating range of the RMR Unit. Following ISO acceptance, an annual routine test shall be conducted at a time chosen by the ISO to verify and confirm the performance of Owner's gas-metering system. With the exception that the test shall be conducted at one load point specified by the ISO, such a test shall be conducted in a similar fashion to the initial acceptance test and shall include inspection of the primary flow element; instrument end-to-end calibration; confirmation of integrity of sensing lines (meaning there shall be no leaks); confirmation of proper GC operation; and proper flow-computer operation and data handling. All systems and sub-systems utilized during the initial acceptance test, including, but not limited to, (a) all primary devices, including the differential producing device of the gas metering system, the GC, and differential pressure ("dP") and temperature instruments; (b) all secondary devices and circuits, including dP and temperature transmitters and circuits, sensing lines, GC sampling line and secondary circuits; and (c) all electronic devices, flow computers and devices, shall be sealed with an ISO-certified seal and no maintenance work or modifications and changes, including making any changes to flow computer programming, shall be permitted without prior approval by the ISO.

If any part of the option (ii) gas-metering system requires either routine or emergency maintenance, the Owner shall notify the ISO immediately by telephone or other means specified by the ISO. The Owner shall inform the ISO of the time period during which such maintenance is expected to occur. The ISO may, at its discretion, require gas-metering systems which are changed or modified during maintenance or repair to undergo re-certification, including acceptance testing. If the maintenance activity is necessary due to concerns that the gas-metering system is not operating in accordance with the required accuracy standards, such maintenance work shall be completed within 2 business days from the time when the concern was first noted.
A V-cone meter may not be used under option (ii), unless the meter was installed prior to January 1, 1997.

If, as a result of a change in the use of fuel gas from a supplier other than the local distribution company, the properties of the fuel gas change materially (Higher Heating Value (HHV) or Specific Gravity (SG) varies more than –3 percent to +3 percent due to the addition of new gas constituents) following the installation of a gas metering system under option (ii) or option (iii), Owner shall notify the ISO within twenty-four (24) hours. Acceptance testing shall be conducted to verify the metering accuracy due to the change in fuel gas supply and to test whether Owner's gas metering system meets the technical requirements of this specification. Owner shall be obligated to install any equipment necessary to bring its gas metering system into compliance. Owner shall not enter into any third-party agreements for non-pipeline grade fuel gas without the prior approval of the ISO. Such approval shall not be granted until the ISO has evaluated Owner's gas metering system, including the effect of the non-pipeline grade fuel gas on metering accuracy.

If an Owner selects option (iii) and the Facility has multiple sources of fuel gas, the local gas distribution company shall install a GC which analyzes all constituents of the blended gas, with the sampling point downstream of the individual supplies such that proper mixing occurs prior to sampling. The GC speed loop should permit analysis of the gas in "real time".

(b) If the fuel is other than natural gas, the Fuel Meter value shall be determined monthly by measuring the fuel oil consumed during the month using, at Owner's one-time election, either (i) a metering process which is acceptable to the Owner and ISO or (ii) a calculation acceptable to the Owner and ISO based on a tank-volume measurement process performed on the day immediately prior to the beginning of the Month and the last day of the Month and fuel oil deliveries during the Month. The metering or measurement process adopted shall comply with, or be comparable to, one or more applicable American Petroleum Institute ("API") Manual of Petroleum Measurement Standards.[3] If Owner and ISO cannot agree on an acceptable process, it shall be determined through ADR pursuant to Schedule K to this Agreement. Owner shall be permitted to change its election between metering as described in (i) above or tank volume measurement described in (ii) above only to reflect changes in the physical circumstances of the Unit or a change in the type of fuel burned at the Unit.

During any period in which the Fuel Meter fails to accurately measure gas flow, the Owner shall provide information to the ISO sufficient to estimate the gas flow during such failure. This information may include unit electric-generating history, accurate recorded gas flow based on another meter and heat input characteristics of all Units served by the failed meter. This information will be used to estimate the gas flow during the failure period to the mutual satisfaction of the ISO, the Responsible Utility and the Owner.

If a Fuel Meter serves RMR Units as well as other units, the heat input characteristics of the other units will be included in Table C1-7a or C1-7b, as applicable, and the Monthly sum of the Unit Hourly Cap Heat Inputs for all units at the Facility metered by the Fuel Meter used in Equation C1-2 will include Hourly Cap Heat Inputs for such other units calculated using Equation C1-7a or C1-7b, whichever is applicable.

- ISO Monthly Fuel Price is calculated in accordance with Equation C1-3.

- Monthly Start-Up Fuel Cost is the sum of the Start-Up Fuel Costs for all Start-ups (for

[3] The applicable API Manual of Petroleum Measurement Standards are: Chapter 2.2A (Measurement and Calibration of Upright Cylindrical Tanks by the Manual Strapping Method); Chapter 3.1B (Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging); Chapter 3.3 (Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging); Chapter 5.2 (Measurement of Liquid Hydrocarbons by Displacement Meters); and Chapter 5.3 (Measurement of Liquid Hydrocarbons by Turbine Meters).

Market and Nonmarket Transactions) in the Month for all units metered by the Fuel Meter with the Start-up Fuel Costs for each Unit calculated in accordance with Equations D-1a or D-1b in Schedule D, as applicable. If a Start-up is initiated but is not successfully completed, the Start-up Fuel Costs shall be adjusted in accordance with Equation C1-2a:

Equation C1-2a

$$\begin{array}{c}\text{Adjusted}\\ \text{Start-up}\\ \text{Fuel Cost}\\ \text{for Canceled}\\ \text{Starts}\\ (\$)\end{array} = \frac{\begin{array}{c}\text{Number of hours}\\ \text{committed to the}\\ \text{Start-up}\end{array}}{\begin{array}{c}\text{Applicable}\\ \text{Start-up Lead Time}\\ \text{in hours shown in}\\ \text{Section 6 of}\\ \text{Schedule A}\end{array}} \times \begin{array}{c}\text{Start-up}\\ \text{Fuel Costs}\\ (\$)\end{array}$$

Where:

- The “number of hours committed to the Start-up” is the lesser of (a) time elapsed between the initiation of the Start-up and the cancellation or (b) the Applicable Start-up Lead Time as shown in Section 6 of Schedule A.

3. ISO Monthly Fuel Price

The ISO Monthly Fuel Price is calculated in accordance with Equation C1-3.

Equation C1-3

$$\text{ISO Monthly Fuel Price (\$/MMBtu)} = \frac{\text{Monthly sum of ISO Unit Hourly Cap Fuel Cost (\$)}}{\text{Monthly sum of ISO Unit Hourly Cap Heat Input (MMBtu)}}$$

Where:

- ISO Unit Hourly Cap Fuel Cost ($) is calculated in accordance with Equation C1-5;
- ISO Unit Hourly Cap Heat Input (MMBtu) is calculated in accordance with Equation C1-6.

4. Intentionally Omitted (There is no Equation C1-4.)

5. ISO Unit Hourly Cap Fuel Cost

For each hour, the ISO Unit Hourly Cap Fuel Cost is calculated in accordance with Equation C1-5.

Equation C1-5

$$\text{ISO Unit Hourly Cap Fuel Cost (\$)} = \text{ISO Unit Hourly Cap Heat Input (MMBtu)} \times \text{Hourly Fuel Price (\$/MMBtu)}$$

Where:

- The Hourly Fuel Price is calculated in accordance with Equation C1-8;
- The ISO Unit Hourly Cap Heat Input (MMBtu) is calculated in accordance with Equation C1-6.

6. **ISO Unit Hourly Cap Heat Input**

For each hour, the ISO Unit Hourly Cap Heat Input is calculated in accordance with Equation C1-6.

Equation C1-6

$$\text{ISO Unit Hourly Cap Heat Input} = \text{Unit Hourly Cap Heat Input (MMBtu)} \times \frac{\text{Billable MWh}}{\text{Hourly Metered Total Net Generation (MWh)}}$$

Where:

- Unit Hourly Cap Heat Input is calculated in accordance with either Equation C1-7a or C1-7b.

7. **Unit Hourly Cap Heat Input (MMBtu)**

The Unit Hourly Cap Heat Input to a Unit for any load is given by the following equations and shall be determined either by a polynomial equation (C1-7a) or exponential equation (C1-7b):

Equation C1-7a

$$\text{Unit Hourly Cap Heat Input} = 1.02 \times (AX^3 + BX^2 + CX + D) * E$$

Equation C1-7b

$$\text{Unit Hourly Cap Heat Input} = 1.02 \times (A * (B + CX + De^{FX})) * E$$

Where:

- X is Unit's Hourly Metered Total Net Generation, MWh;
- e is the base of natural logarithms;
- A, B, C, D are coefficients given for Equation C1-7a in Table C1-7a and given for Equation C1-7b in Table C1-7b;
- The coefficient E is applicable only when burning fuel oil. At all other times, it shall be set to 1.0.
- F is a coefficient given in Table C1-7b.

Table C1-7a

A	B	C	D	E

Table C1-7b

A	B	C	D	E	F

8. Hourly Fuel Price

The Hourly Fuel Price for Units shall be the same for each hour of a given day and is calculated in accordance with Equation C1-8.

Equation C1-8 (Gas)

Hourly Fuel Price ($/MMBtu) = Commodity Price ($/MMBtu) + Intrastate Transportation Rate ($/MMBtu)

Equation C1-8 (Oil)

Hourly Fuel Price ($/MMBtu) = Commodity Price ($/MMBtu) + Transportation Rate ($/MMBtu)

Commodity Price for Natural Gas

For the Facilities within the service area of SCE or SDG&E, the Commodity Price shall be the product of 1.02 and the simple average of the following indices:

Gas Daily, SoCal Gas, Large Packages index (midpoint)
BTU Daily Gas Wire, SoCal Border index, Topock
NGI Daily Gas Price Index, Southern California Border (average)

For the Facilities within the service territory of PG&E, the Commodity Price shall be the product of 1.02 and the simple average of the following indices:

Gas Daily, PG&E Citygate index (midpoint)
NGI Daily Gas Price Index, PG&E Citygate (average)

The indices to be used for each Settlement Period in a given day are shown in Table C1-8. Where more than one day's index is shown for a Trading Day, the average of the two daily indices should be used. If an applicable index for a day, which is used to compute the index's average for a Trading Day, is not published, then that index will not be used to compute the Commodity Price for that trading day. If no index for a day is published, then the average of applicable indices on the Index Publication Date preceding and the Index Publication Date following such day will be substituted for the Index Publication Date index for that day in Table C1-8. In the event that an index ceases to be published, Parties shall agree on a replacement index.

Table C1-8
Natural Gas Price Indices

		Index Publication Date*	
Trading Day	Gas Daily **	Btu Daily ** Gas Wire	NGI Daily ** Price Index
Tuesday	Tuesday/ Wednesday	Monday/ Tuesday	Tuesday/ Wednesday
Wednesday	Wednesday/ Thursday	Tuesday/ Wednesday	Wednesday/ Thursday
Thursday	Thursday/ Friday	Wednesday/ Thursday	Thursday/ Friday
Friday	Friday/ Monday	Thursday/ Friday	Friday/ Monday
Saturday	Monday/ Tuesday	Friday/ Monday	Monday/ Tuesday
Sunday	Monday/ Tuesday	Friday/ Monday	Monday/ Tuesday
Monday	Monday/ Tuesday	Friday/ Monday	Monday/ Tuesday

* *The Index Publication Date is the date of the publication which contains the prices for the applicable Trading Day.*

** *Where more than one day's index is shown for a Trading Day, the average of the two daily indices should be used.*

Gas Daily: The "Flow Date(s)" column should match the Trading Day.

Btu Daily: The Index Publication Date should be the day prior to the Trading Date in the Table above, except for Sunday and Monday, where Friday should be used as the Index Publication Date.

NGI Daily: The Index Publication Date should be the same as the Trading Date in the tables above, except for Saturday and Sunday, where Monday should be used as the Index Publication Date.

Commodity Price for Distillate Fuel Oil

The Commodity Price for Distillate Fuel Oil shall be the simple average of the midpoint of the ranges for CARB No. 2 Diesel and for Jet as published in Platt's Oilgram United States West Coast Product Assessments (page 22). If the Unit can burn only Jet, the Commodity Price shall be the midpoint of the range for Jet.

In an event the index ceases to be published, the Parties shall agree on a replacement index.

For distillate fuel, the index will be for the last day prior to the RMR Transaction Day.

Commodity Price for No. 6 Residual Fuel Oil

The fuel price shall be the prudent actual replacement cost of the fuel consumed, or, if the fuel is consumed and not replaced, then the fuel price will be "last-in-first-out" (LIFO) inventory price of the fuel consumed.

Where conversion from barrels of Fuel to MMBtu is required, the following conversion coefficients shall be used:

- No. 1 Distillate Fuel Oil - 5.754 MMBtu per barrel;
- No. 2 Distillate Fuel Oil - 5.796 MMBtu per barrel;
- Jet Fuel - 5.650 MMBtu per barrel;
- No. 6 Residual Fuel Oil - 6.258 MMBtu per barrel.

Intrastate Transportation Rate for Gas

The Intrastate Transportation Rate for Gas shall be the applicable intrastate transportation rate determined as follows:

Units served by SDG&E: The Southern California Gas Company intrastate transportation rate (currently GT-SD) plus the volumetric component of the SDG&E gas transportation rate for electric generation service, including the ITCS[4] (currently GTUEG – SD), or any successor rate for electric generation service applicable to deliveries to the Facility, divided by one minus the applicable in-kind shrinkage allowance, if any.

Units served by Southern California Gas: The Southern California Gas Company intrastate transportation rate for firm electric generation service, including the ITCS (GT-F) plus the G-ITC Wheeler Ridge Interconnection Access fee, if applicable, or any successor rate for firm electric generation service applicable to deliveries to the Facility, divided by one minus the applicable in-kind shrinkage allowance, if any.

Units served by PG&E: The PG&E intrastate transportation charge stated in Rate Schedule GEG, or any successor rate for electric generation service applicable to deliveries to the Facility, divided by one minus the applicable in-kind shrinkage allowance, if any.[5]

Transportation Rate for Distillate Fuel Oil

The Transportation Rate for Distillate Fuel Oil shall be __________. There shall be no Transportation Rate for No. 6 Residual Fuel Oil.

[4] ITCS means Interstate Transition Cost Surcharges.
[5] If the Facility does not qualify for service under Rate Schedule G-EG, the applicable rate shall be given by Rate Schedule G-NT.

B. ISO Monthly Fuel Imbalance Charge

Levels of Responsibility

Each month, the Owner is responsible for all Nonmarket fuel imbalance charges incurred up to and including 2.25 percent of the ISO Facility Monthly Billed Fuel Cost.

The Monthly Fuel Imbalance Charge is equal to 75% of 1st Tier Imbalance plus 100% of 2nd Tier Imbalances;

Where:

The **1st Tier Imbalances** is that portion of the Monthly Sum of Daily Imbalance Charges which exceeds 2.25 percent of the ISO Facility Monthly Billed Fuel Cost for the Month and is less than or equal to 10.0 percent of the ISO Facility Monthly Billed Fuel Cost for the Month.

The **2nd Tier Imbalances** is that portion of the Monthly Sum of Daily Imbalance Charges which is greater than 10.0 percent of the ISO Facility Monthly Billed Fuel Cost for the Month.

The Monthly Sum of Daily Imbalance Charges is the sum for all days in the month of imbalance charges and similar fees and penalties imposed on Owner (or its fuel supplier and paid by Owner) by transportation providers delivering gas to the Units because deliveries were in excess of or less than scheduled for a given day, but only to the extent that (i) the imbalance was caused by Owner compliance with a Dispatch Notice issued after (or less than 30 minutes prior) to the Transporter's deadline for scheduling transportation, and (ii) Owner issued a notice to the ISO as soon as possible after the Owner became aware it might incur imbalance charges advising ISO of such possible charges.

In any month in which Owner incurs a 1st Tier or 2nd Tier Imbalance charge, Owner will provide the ISO with a report showing the allocation of the imbalance charges between Market Transactions and Nonmarket Transactions. If ISO or the Responsible Utility disagree on allocation, the dispute will be resolved through ADR.

To receive payment for a 2nd Tier Imbalance, Owner must document in an informational filing with FERC that the charges were appropriately allocated to Nonmarket Transactions and it was commercially reasonable to incur them. As used in this context and for purposes of calculating imbalance charges, "commercially reasonable" does not mean that Owner is required to acquire storage to avoid imbalances. If either the ISO or Responsible Utility disagree with the imbalance charges, desires a formal review and gives such notice to the Owner within 30 days of the informational filing, the Owner must file under Section 205 of the Federal Power Act to collect any 2nd Tier Imbalance charges.

Pursuant to the above, the Monthly Fuel Imbalance Charge is calculated in accordance with Equation C1-9.

Equation C1-9

$$\text{Monthly Fuel Imbalance} = 0.75 \times \left[\begin{array}{c}\text{Monthly}\\\text{Sum of}\\\text{Daily}\\\text{Imbalance}\end{array} - 0.0225 \times \begin{array}{c}\text{ISO}\\\text{Facility}\\\text{Monthly}\\\text{Billed}\end{array}\right] + 0.25 \times \left[\begin{array}{c}\text{Monthly}\\\text{Sum of}\\\text{Daily}\\\text{Imbalance}\end{array} - 0.10 \times \begin{array}{c}\text{ISO}\\\text{Facility}\\\text{Monthly}\\\text{Billed}\end{array}\right]$$

Charge	| ?	Charges	✍	Fuel Cost	| ?	✍	? Charges	✍	Fuel Cost ?

Note that if either of the two bracketed portions of the equation yields a value less than or equal to zero, then that portion of the equation is set to zero.

C. <u>ISO Monthly Other Fuel Related Cost</u>

The ISO Monthly Other Fuel Related Cost is calculated in accordance with Equation C1-10.

Equation C1-10

$$\text{ISO Monthly Other Fuel Related Cost} = \frac{\text{Monthly sum of Billable MWh}}{\text{Monthly sum of Total Hourly Metered Net Generation}} \times \left[\text{Other Gas Tariff Charges} - \text{Applicable Taxes} \right]$$

Where:

- Other Gas Tariff Charges are those intrastate gas transportation tariff charges not included in Transportation Rate Charges set forth in Section A.8 of this Schedule listed below:

  [Insert applicable charges]

- Applicable taxes and fees are:

  1. [Insert applicable local utility user taxes]

  2. [Insert applicable G-SUR fee]

All other fuel related taxes and fees are intended to be covered by the two percent adder in Hourly Fuel Cost and are the Owner’s responsibility.

D. <u>ISO Monthly Emissions Cost</u>

Part 1 for SCAQMD-Jurisdictional Thermal Units

The ISO Monthly Emissions Cost for each Unit shall be the sum, for all hours in the month, of the ISO Hourly Emissions Cost. These costs apply to a Facility within the South Coast Air Quality Management District (SCAQMD).

The ISO Hourly Emissions Cost shall be calculated in accordance with Equation C1-11.

Equation C1-11

ISO Hourly Emissions Cost ($/hr) =
a. ISO Hourly RECLAIM Trading Credit Cost ($/hr) +
b. ISO Hourly NOx Emissions Cost ($/hr) +
c. ISO Hourly Organic Gases Emissions Cost ($/hr) +
d. ISO Hourly Sulfur Oxides Emissions Cost ($/hr) +

e. ISO Hourly Particulate Matter Emissions Cost ($/hr)+
f. ISO Hourly Carbon Monoxide Emissions Cost ($/hr) +
g. ISO Hourly Sulfur Dioxides Trading Credit Costs ($/hr)

a. <u>ISO Hourly RECLAIM Trading Credit Cost</u>

For each hour, the ISO Hourly RECLAIM Trading Credit ("RTC") Cost for NOx emissions required for the Unit to generate the Billable MWh is calculated in accordance with Equation C1-12.

Equation C1-12

$$\text{ISO Hourly RECLAIM Trading Credit Cost (\$/hr)} - \text{Hourly } NO_x \text{ Emissions (lbs/hr)} ✍ \text{RECLAIM } NO_x \text{ Trading Credit Rate (\$/lb)} ✍ \frac{\text{Billable MWh}}{\text{Hourly Metered Total Net Generation}}$$

Where:

· Hourly NOx Emissions is calculated in accordance with Equation C1-13.

Equation C1-13

$$\text{Hourly NOx Emissions (lbs/hr)} = AX^2 + BX + C$$

<u>Where</u>:

· X is the Hourly Metered Total Net Generation for the hour.

· Coefficients A, B, and C are given in Table C1-13 for each Unit.

Table C1-13

Description of Unit	**A**	**B**	**C**

The RECLAIM NOx Trading Credit Rate ($/lb) will be equal to the 13-week sales-weighted average sales price for RTCs calculated as of the last day of the Month from sales records available from the SCAQMD for all actual sales in the SCAQMD during the thirteen preceding weeks, including the Settlement Period.

b. <u>ISO Hourly NOx Emissions Cost</u>

For each hour, the ISO Hourly NOx Emissions Cost for the Billable MWh is calculated in accordance with Equation C1-14.

Equation C1-14

$$\text{ISO Hourly NOx Emissions Cost (\$/hr)} = (5 * 10^{-4}) * \text{Hourly NOx Emissions (lbs/hr)} * \text{NOx Emissions Fee (\$/ton)} \text{ ✍ } \frac{\text{Billable MWh}}{\text{Hourly Metered Total Net Generation}}$$

Where:

- $(5 * 10^{-4})$ is the conversion factor from lbs to tons.
- Hourly NOx Emissions is calculated in accordance with Equation C1-13.
- NOx Emissions Fee is obtained from Table III of SCAQMD Rule 301(e). The fee is dependent upon the Cumulative Tons of Pollutant (NOx), which is calculated in accordance with Equation C1-15. The Cumulative Tons of Pollutant is reset to zero each July 1st.

Equation C1-15

$$\text{Cumulative Tons of Pollutant (tons/hr)} = \text{Tons of Pollutant From the prior July 1}^{st} \text{ to the Previous Hour} - \text{Tons of Pollutant For Current Hour}$$

Where:

- Tons of Pollutant for Current Hour is in accordance with Equation C1-16.

Equation C1-16

$$\text{Tons of Pollutant for Current Hour (tons/hr)} = (4.76 * 10^{-7}) * (AX^3 + BX^2 + CX + D) \text{ ✍ } \text{Pollutant Emissions Amount for Natural Gas}$$

Where:

- $(4.76 * 10^{-7})$ is the conversion factor from lbs. to tons (1 ton/2000 lbs.) and from mmcf to MMBtu (1 mmcf/1050 MMBtu).
- X is the Hourly Metered Total Net Generation, MWh.
- Coefficients A, B, C, and D are the coefficients of the hourly heat rate curve given in Table C1-16 for each Unit.

Table C1-16

Description of Unit	A	B	C	D

Pollutant Emissions Amount For Natural Gas is the applicable pollutant from SCAQMD General

Instruction Book (for the latest year), Annual Emissions Reporting Program, Appendix A - Common Emission Factors For Combustion Equipment, Table 1 - Common Emission Factors For Combustion Equipment for Forms B1 and B1U.

c. - f. **<u>ISO Hourly Organic Gases Emissions Cost, ISO Hourly Sulfur Oxides Emissions Cost, ISO Hourly Particulate Matter Emissions Cost, and ISO Hourly Carbon Monoxide Emissions Cost</u>**

The ISO Hourly Organic Gases (OG) Emissions Cost, ISO Hourly Sulfur Oxides (SOx) Emissions Cost, ISO Hourly Particulate Matter (PM) Emissions Cost, and ISO Hourly Carbon Monoxide (CO) Emissions Cost are each calculated in accordance with Equation C1-17.

Equation C1-17

$$\begin{array}{c}\text{ISO Hourly}\\ \text{Applicable}\\ \text{Emissions Cost}\\ (\$/\text{hr})\end{array} = (4.76 * 10^{-7}) \times \begin{array}{c}\text{ISO Unit Hourly}\\ \text{Cap Heat Input}\\ (\text{MMBtu/hr})\end{array} \times \begin{array}{c}\text{Associated}\\ \text{Emissions Factor}\\ (\text{lbs/mmcf})\end{array} \times \begin{array}{c}\text{Associated}\\ \text{Emissions Fee}\\ (\$/\text{ton})\end{array}$$

Where:

- ISO Hourly Applicable Emissions Cost is the ISO Hourly OG Emissions Cost, ISO Hourly SOx Emissions Cost, ISO Hourly PM Emissions Cost, or ISO Hourly CO Emissions Cost.

- $(4.76 * 10^{-7})$ is the conversion factor from lbs. to tons (1 ton/2000 lbs.) and from mmcf to MMBtu (1 mmcf/1050 MMBtu).

- Associated Emissions Factor is the associated OG Emissions Factor, SOx Emissions Factor, PM Emissions Factor or CO Emissions Factor from Table 1 from General Instruction Book for the SCAQMD (for the latest year) Annual Emissions Reporting Program.

- Associated Emissions Fee is the associated OG Emissions Fee, SOx Emissions Fee, PM Emissions Fee, or CO Emissions Fee from Table III of SCAQMD Rule 301(e), and is dependent upon the Cumulative Tons of Pollutant pursuant to Equation C1-15.

g. **<u>ISO Hourly Sulfur Dioxides Trading Credit Costs</u>**

Beginning in the year 2000, certain Units will be subject to Title IV of the Federal Clean Air Act for providing SO_2 Allowances to cover related trading costs. Prior to 2000, the ISO Hourly Sulfur Dioxides Trading Credit Cost will be zero. The Owner may make a filing under Section 205 of the Federal Power Act limited to recovering applicable ISO Hourly Sulfur Dioxides Trading Credit Costs when such costs are incurred.

<u>Part 2 for Ventura County Air Pollution Control District</u>[6]

Beginning in the year 2000, certain Units will be subject to Title IV of the Federal Clean Air Act for providing SO_2 Allowances to cover related trading costs. Prior to 2000, the ISO Hourly Sulfur Dioxides Trading Credit Cost will be zero. The Owner may make a filing under Section 205 of the

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[6] Ventura County APCD, where Mandalay Generating Station is located, does not require payment of emissions fees, but rather permit renewal fees. The permit renewal fees are included in the fixed O&M costs.

Federal Power Act limited to recovering applicable ISO Hourly Sulfur Dioxides Trading Credit Costs when such costs are incurred.

E. **ISO Monthly Variable O&M Cost**

The ISO Monthly Variable O&M Cost for each Unit shall be the product of the Unit's Billable MWh for the Billing Month and the Unit's Variable O&M Rate. Variable O&M Rate for each Unit shall be:

Table C1-18

Unit	Variable O&M Rate ($/MWh)

F. **ISO Scheduling Coordinator Charge**

The ISO Scheduling Coordinator Charge for each Unit shall be the product of PX Administration Charge as charged under the PX Tariff and the Unit's Billable MWh for the Billing Month.

G. **ISO ACA Charge**

The ISO ACA Charge is the product of the Unit's Billable MWh for the Billing Month and the applicable annual charge for short-term sales under 18 CFR Section 382.201 of the FERC Regulations.

SCHEDULE C

Variable Cost Payment for All Conditions

Part 2 for Geothermal Units

For each Unit each Month, the Variable Cost Payment for Billable MWh from the Unit pursuant to Nonmarket Transactions during that Month shall be the amount calculated in accordance with the following formula:

Variable Cost Payment = A. ISO Monthly Billed Fuel Cost +
B. ISO Monthly Variable O&M Cost +
C. ISO Scheduling Coordinator Charge +
D. ISO ACA Charge

Each component of the Variable Cost Payment for geothermal Units is calculated as described below:

A. <u>ISO Monthly Billed Fuel Cost</u> [for Geysers Main only]

The ISO Monthly Billed Fuel Cost is given by Equation C2-1.

Equation C2-1

ISO Monthly Billed Fuel Cost = Billable MWh ✍ Steam Price ($/MWh)

Where:

· Steam Price is $16.34/MWh.

· For purposes of Equation C2-1, Billable MWh is all Billable MWh Delivered after cumulative Hourly Metered Total Net Generation during the Contract Year from all Units exceeds the Minimum Annual Generation given by Equation C2-2.

Equation C2-2

Minimum Annual Generation = (Annual Average Field Capacity ✍ 8760 hours *x* 0.4) - (A+B+C)

Where:

· Annual Average Field Capacity is the arithmetic average of the two Field Capacities in MW for each Contract Year, determined as described below.

Field Capacity shall be determined for each six-month period from July 1 through December 31 of the preceding calendar year and January 1 through June 30 of the Contract Year. Field Capacity shall be the average of the five highest amounts of net generation (in MWh) simultaneously achieved by all Units during eight-hour periods within the six-month period. The capacity simultaneously achieved by all Units during each eight-hour period shall be the sum of Hourly Metered Total Net Generation for all Units

during such eight-hour period, divided by eight hours. Such eight-hour periods shall not overlap or be counted more than once but may be consecutive.
Within 30 days after the end of each six-month period, Owner shall provide ISO and the Responsible Utility with its determination of Field Capacity, including all information necessary to validate that determination.

- A is the amount of Energy that cannot be produced (as defined below) due to the curtailment of a Unit during a test of the Facility, a Unit or the steam field agreed to by ISO and Owner.

- B is the amount of Energy that cannot be produced (as defined below) due to the retirement of a Unit or due to a Unit's Availability remaining at zero after a period of ten Months during which the Unit's Availability has been zero.

- C is the amount of Energy that cannot be produced (as defined below) because a Force Majeure Event reduces a Unit's Availability to zero for at least thirty (30) days or because a Force Majeure Event reduces a Unit's Availability for at least one hundred eighty (180) days to a level below the Unit Availability Limit immediately prior to the Force Majeure Event.

- The amount of Energy that cannot be produced is the sum, for each Settlement Period during which the condition applicable to A, B or C above exists, of the difference between the Unit Availability Limit immediately prior to the condition and the Unit Availability Limit during the condition.

A. <u>ISO Monthly Billed Fuel Cost</u> [for Geysers Units 13 & 16 only]

The ISO Monthly Billed Fuel Cost is given by Equation C2-1.

Equation C2-1

ISO Monthly Billed Fuel Cost = Billable MWh ? Steam Price ($/MWh)

Where:

- Steam Price is $11.25/MWh, which includes the cost of steam condensate re-injection.

B. <u>ISO Monthly Variable O&M Cost</u>

The ISO Monthly Variable O&M Cost for each Unit is given by Equation C2-3 and is the product of the sum of Billable MWh for the Billing Month and the Unit's Variable O&M Rate. Variable O&M Rate for each Unit is shown in Table C2-1:

Equation C2-3

ISO Monthly Variable O&M Cost = Monthly sum of Billable MWh ? Variable O&M Rate

Table C2-1

Unit	Variable O&M Rate ($/MWh)

C. ISO Scheduling Coordinator Charge

The ISO Scheduling Coordinator Charge for each Unit shall be the product of PX Administration Charge as charged under the PX Tariff and the Unit's of Billable MWh for the Billing Month.

D. ISO ACA Charge

The ISO ACA Charge is the product of the Unit's Billable MWh for the Billing Month and the applicable annual charge for short-term sales under 18 CFR Section 382.201 of the FERC Regulations, to the extent payable by Owner for Billable MWh.

SCHEDULE C

Variable Cost Payment for All Conditions

Part 3 for Conventional Hydro Units

For each month and each Unit, the Variable Cost Payment for Billable MWh from the Unit pursuant to Nonmarket Transactions during that Month shall be the amount calculated in accordance with the following formula:

Variable Cost Payment = A. ISO Scheduling Coordinator Charge +
B. ISO ACA Charge

A. **<u>ISO Scheduling Coordinator Charge</u>**

The ISO Scheduling Coordinator Charge for each Unit shall be the product of PX Administration Charge as charged under the PX Tariff and the Unit's Billable MWh for the Billing Month.

B. **<u>ISO ACA Charge</u>**

The ISO ACA Charge is the product of the Unit's Billable MWh for the Billing Month and the applicable annual charge for short-term sales under 18 CFR Section 382.201 of the FERC Regulations.

SCHEDULE C

Variable Cost Payment for All Conditions

Part 4 for Pumped Storage Hydro Units

For each month and each Unit, the Variable Cost Payment for Billable MWh from the Unit pursuant to Nonmarket Transactions during that Month shall be the amount calculated in accordance with the following formula:

Variable Cost Payment =
A. ISO Monthly Billed Fuel Cost +
B. ISO Scheduling Coordinator Charge +
C. ISO ACA Charge

A. <u>ISO Monthly Billed Fuel Cost</u>

The ISO Monthly Billed Fuel Cost is given by Equation C4-1:

Equation C4-1

ISO Monthly Billed Fuel Cost = Year-to-Date ISO Fuel Cost – Sum of Previous Months' ISO Monthly Billed Fuel Cost in the Contract Year

Where:

- Year-to-Date ISO Fuel Cost is given by Equation C4-2.
- Sum of Previous Months' ISO Monthly Billed Fuel Cost in the Contract Year shall be the sum of the ISO Monthly billed Fuel Cost for each Month from January 1 of the Contract Year[7] through the end of the Month in the Contract Year before the Billing Month.

Equation C4-2

Year-to-Date ISO Fuel Cost = (YTD Pumping Cost/YTD Energy Produced) ✍ YTD Billable MWh

Where:

- YTD Pumping Cost =Total cost of Energy purchased by Owner for pumping, including transmission charges, from January 1 of the Contract Year through the end of the Billing Month.

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[7] For purposes of Equations C4-1 and C4-2 as applied in 1999, Contract Year includes those months in the year, beginning in January 1999, when the same services as under this Agreement were provided to ISO under a predecessor rate schedule, as well as months when such services are provided under this Agreement.

- YTD Energy Produced =Total Energy produced by the Facility for Market and Nonmarket Transactions from January 1 of the Contract Year through the end of the Billing Month.

- YTD Billable MWh =Total Billable MWh from January 1 of the Contract Year through the end of the Billing Month.

B. <u>ISO Scheduling Coordinator Charge</u>

The ISO Scheduling Coordinator Charge for each Unit shall be the product of PX Administration Charge as charged under the PX Tariff and the Unit's Billable MWh for the Billing Month.

C. <u>ISO ACA Charge</u>

The ISO ACA Charge is the product of the Unit's Billable MWh for the Billing Month and the applicable annual charge for short-term sales under 18 CFR Section 382.201 of the FERC Regulations.

SCHEDULE D

Part 1

Start-up Payment for Condition 1 Units

1. <u>Prepaid Start-up Charge</u>

Prepaid Start-up Charge for each Unit operating under Condition 1 for each Contract Year will be calculated as the Prepaid Start-up Cost times the number of Prepaid Start-ups. The number of Prepaid Start-up equals the Maximum Annual Start-ups per Unit. The Prepaid Start-up Cost will be calculated in accordance with Equation D-1 for Start-up Cost with the following assumptions:

a) Hourly Fuel Price: For the initial Contract Year the Hourly Fuel Price shall be the simple average of the applicable index prices from Table C1-8 of Schedule C for the period beginning on the later of the initial publication date of such indices or January 1, 1998 and ending December 31, 1998, plus the applicable Transportation Rate under Equation C1-8 as in effect on April 1, 1999. For each subsequent Contract Year, the Hourly Fuel Price shall be agreed upon by ISO and Owner; if there is no agreement, the Hourly Fuel Price shall be the simple average of the Hourly Fuel Prices for the twelve months ending the prior June 30 as calculated in accordance with Equation C1-8 of Schedule C;

b) Energy Price shall be based on the [insert Applicable UDC Tariff rate], including applicable demand charges, provided that the Applicable UDC Tariff rate shall only be the energy charge rate at those Facilities where Units have the capability to use Energy from other units at the same Facility to effect Start-ups or where generation from other units is otherwise permitted under the ISO Tariff to be netted against auxiliary power needed to effect Start-up of the Unit. For the initial Contract Year, the Energy Price shall be calculated as the total auxiliary power (including Energy for Start-ups) costs charged to the Facility by its supplier of end-use Energy for the six-month period ending December 31, 1998 divided by the auxiliary power (including Energy for Start-ups) consumed at the Facility for that same time period. For Facilities that have not been charged for auxiliary power for the six-month period ending December 31, 1998, the Energy Price for the Initial Contract Year shall be the simple average of the prices for Energy for varying times of day shown in the Applicable UDC Tariff. For each subsequent Contract Year, the Energy Price shall be calculated as the total auxiliary power (including Energy for Start-ups) costs charged to the Facility by its supplier of end-use Energy for the twelve months ending the prior June 30 divided by the auxiliary power (including Energy for Start-ups) consumed at the Facility for that same twelve-month period;

c) All Start-ups are assumed to be from maximum time off line as shown by value X_{Max} in Table D-1, and

d) Other Start-up Costs shall be zero ($0) for non-hydroelectric Units; for hydroelectric Units, other Start-up costs shall be the cost shown in Table D-2 for Normal Work Hours.

The Prepaid Start-up Cost and Prepaid Start-up Charge for the current Contract Year are set forth in Table D-0:

Table D-0

Number of	Prepaid	Prepaid

	Prepaid Start-ups	Start-up Cost	Start-up Charge
Unit			
Unit			
Unit			

2. Start-up Cost

The cost for a Start-up shall be calculated in accordance with Equation D-1:

Equation D-1

$$\underset{(\$)}{\text{Start-up Cost}} = \underset{(\$)}{\text{Start-up Fuel Cost}} + \underset{(\$)}{\text{Start-up Power Cost}} + \underset{(\$)}{\text{Other Start-up Costs}} + \underset{(\$)}{\text{Shutdown Power Cost}}$$

Each component of the Start-up Cost in Equation D-1 is set forth below.

a. Start-up Fuel Costs

The Start-up Fuel Cost shall be calculated in accordance with Equation D-1a:

Equation D-1a

$$\underset{(\$)}{\text{Start-up Fuel Cost}} = \left[\left(\underset{(\text{MMBtu/hr})}{A} \times \underset{(\text{hrs})}{x} \right) - \underset{(\text{MMBtu})}{B} \right] \times \underset{(\$\text{MMBtu})}{\text{Hourly Fuel Price}}$$

Where:

- "x" equals the number of hours since the Unit ceased operation and cannot exceed "x_{Max}".
- The Hourly Fuel Price is calculated pursuant to Schedule C Equation C1-8 for the hour in which the Start-up began.
- The values A, B and x_{Max} for each Unit are given in Table D-1 below.

b. Start-up Power Costs

The Start-up Power Cost shall be calculated in accordance with Equation D-1b:

Equation D-1b

$$\underset{(\$)}{\text{Start-up Power Cost}} = \left(\left[\underset{(\text{MWh/hr})}{C} \times \underset{(\text{hrs})}{x} \right] + \underset{(\text{MWh})}{D} \right) \times \underset{(\$/\text{MWh})}{\text{Energy Price}}$$

Where:

- "x" is equal to the hours since the Unit ceased operation and cannot exceed "x_{Max}".
- The Energy Price shall be equal to the total auxiliary power (including Energy for Start-ups) costs charged to the Facility by its supplier of end-use Energy for the billing cycle in which the Start-up was initiated divided by the total auxiliary power (including Energy for Start-ups) consumed at the Facility during such billing cycle.
- The values C, D and x_{Max} are given in Table D-1 below.

c. **<u>Shutdown Power Costs</u>**

The Shutdown Power Cost shall be calculated in accordance with Equation D-1c:

Equation D-1c

$$\begin{array}{c} \text{Shutdown} \\ \text{Power Cost} \\ (\$) \end{array} = \begin{array}{c} \text{Shutdown Power} \\ \text{Requirement} \\ (\text{MWh}) \end{array} \times \begin{array}{c} \text{Energy} \\ \text{Price} \\ (\$/\text{MWh}) \end{array}$$

The Energy Price shall be equal to the total auxiliary power (including Energy for Shutdowns) costs charged to the Facility by its supplier of end-use Energy for the billing cycle in which the Shutdown was initiated divided by the total auxiliary power (including Energy for Shutdowns) consumed at the Facility during such billing cycle. The Shutdown Power Requirement is given in Table D-1 below.

d. **<u>Other Start-up Costs for Hydroelectric Only</u>**

Other Start-up Costs are the cost of labor to start hydroelectric Units that require an operator to manually parallel, and reflect the labor costs to travel to the site. If the Start-up of a hydroelectric Unit occurs outside normal work hours, the Start-up Costs include the minimum work hours and labor rates as set by the applicable collective bargaining agreement(s).

The Other Start-up Costs shall be calculated in accordance with Equation D1-d. The values for E are provided in Table D-2 for normal work hour and outside of normal work hour situations.

Equation D-1d

$$\text{Other Start-up Costs (\$)} = E$$

Once a Unit has been given a Dispatch Notice to Start-up, other Start-up Costs are incurred.

Table D-1, Start-Up Costs

	x_{Max}	A	B[8]	C	D	Shutdown Power Requirement
Unit	(Hrs)	(mmBtu)/hr	(mmBtu)	(MWh)/hr	(MWh)	(MWh)

Table D-2, Other Start-Up Costs – Hydroelectric Units

Unit	E (Normal Work Hours)	E (Outside Normal Work Hours)
	($)	($)

3. Monthly Start-up Adjustment

For each Start-up successfully completed in compliance with a Dispatch Notice during the Billing Month, and each Start-up initiated in compliance with a Dispatch Notice but not successfully completed because it is canceled or rescinded by ISO, until the total Counted Start-ups for the Contract Year equals the number of Prepaid Start-ups for the Contract Year, the Monthly Start-up Adjustment, which shall be a credit or payment, is the sum of Prepaid Start-up Adjustments, and Prepaid Start-up Adjustments for Canceled Start-ups calculated in accordance with Equations D-2 and D-3:

Equation D-2

Prepaid Start-up Adjustment = Prepaid Start-up Cost calculated in accordance with Section 1 minus the actual Start-up Cost calculated in accordance with Equation D-1.

Equation D-3

Prepaid Start-up Adjustment for Canceled Start-up	=	Number of hours committed to the Start-up applicable Start-up Lead Time (hrs) as shown in Schedule A, Section 6	✍	Prepaid Start-up Adjustment calculated in accordance with Equation D-2

Where:

- The "number of hours committed to the Start-up" is the lesser of (a) time elapsed between the initiation of the Start-up and the cancellation and (b) the applicable Start-up Lead Time.

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[8] Includes fuel consumed from the time Unit reaches Synchronization to the time Unit reaches Minimum Load.

SCHEDULE D

Part 2

Start-up Payment for Condition 2 Units

1. <u>Start-up Payment</u>

The Start-up Payment for each Start-up successfully completed for each Unit operating under Condition 2 equals the Start-up Cost calculated using Equation D-1.

2. <u>Payment for Canceled Start-up</u>

If Start-up is initiated under a Dispatch Notice but is not successfully completed because it is canceled or rescinded by the ISO, the Start-up Payment is calculated in accordance with Equation D-4:

Equation D-4

$$\text{Start-up Payment for Canceled Start-up (\$)} = \frac{\text{Number of hours committed to the Start-up}}{\text{applicable Start-up Lead Time (hrs) as shown in Schedule A, Section 6}} \times \text{Start-up Cost calculated in accordance with Equation D-1 (\$)}$$

The "number of hours committed to the Start-up" is the lesser of (a) time elapsed between the initiation of the Start-up and the cancellation or (b) the applicable Start-up Lead Time.

Schedule E

Ancillary Services
Part 1 for Condition 1

The ISO may call upon the Unit to provide the following Ancillary Services as defined in the ISO Tariff:

Regulation
Spinning Reserve
Nonspinning Reserve
Replacement Reserve
Voltage Support (including synchronous condenser operation)
Black Start

If the Unit is otherwise generating, the Owner shall be required to operate the Unit within the Power Factor range of the Unit specified in Schedule A to provide Ancillary Services without additional compensation.

Certain Units (hydroelectric and synchronous condensers) can provide Ancillary Services without generating Energy. Under this Condition, Owner will be compensated for Motoring Charges if the Unit is providing Ancillary Services while synchronized without generating Energy.

<u>Motoring Charge</u>

When Units are operated as synchronous condensers (i.e., motored using electric power) to provide Ancillary Services, if applicable, the payment for that service is given by the following formula:

Motoring Charge = (Power consumption rate (MWh/hr)) ✍ (hours operated) ✍ (Energy Price)

Where the Power consumption rate is given by the following table:

Unit	Power consumption rate (MWh/hour)

The Energy Price shall be equal to the total power costs charged to the Facility by its supplier of end-use Energy under the Applicable UDC Tariff for the billing cycle in which the Motoring Charge was incurred divided by the total power consumed at the Facility under such tariff during such billing cycle.

<u>Pre-empted Dispatch Payment</u>

If the ISO issues a Dispatch Notice to:

(i) decrease a Unit's scheduled output of Energy in a Market Transaction to provide Ancillary Services;

(ii) decrease a Unit's scheduled provision of Ancillary Services capacity in a Market Transaction in order to provide Regulation, Spinning Reserve, Nonspinning Reserve, or Replacement Reserve pursuant to a Dispatch Notice,

(iii) decrease a Unit's scheduled provision of Ancillary Service capacity in a Market

Transaction in order to provide Energy pursuant to a Dispatch Notice, the ISO shall pay the appropriate Pre-empted Dispatch Payment described below. The Pre-empted Dispatch Payments are intended to make an Owner whole with respect to the original Market Transaction.

A. <u>For Pre-empted Energy Market Transactions</u>:

Pre-empted Dispatch Payment = Imbalance Energy Charge – Cost Savings

- Imbalance Energy Charge = $(X_o - X_n) \times$ Penalty Price
- Penalty Price = Unrestricted Imbalance Energy Price + additional penalties (per MWh) imposed by the ISO for failure to comply with Market Schedules due to compliance with Dispatch Notice.
- Cost Savings = Fuel Cost Savings + Emissions Savings + Other Savings

Where:

- X_o = Original Total Schedule in Market and Nonmarket Transactions;
- X_n = New Total Schedule in Market and Nonmarket Transactions;

<u>For fossil fuel Units, the Fuel Cost Savings is calculated as follows</u>:

- Fuel Cost Savings = Fuel Savings x Hourly Fuel Price
- Fuel Savings = $((AX_o^3+BX_o^2+CX_o+D) - (AX_n^3+BX_n^2+CX_n+D)) \times E$

or

- Fuel Savings = $[(A * (B + CX_o + De^{FXo})) - (A * (B + CX_n + De^{FXn}))] \times E$
- A, B, C, D, E and F are the coefficients from Table C1-7a or C1-7b, as applicable;
- Hourly Fuel Price is calculated in Equation C1-8.

<u>For geothermal Units, the Fuel Cost Savings is calculated by the following formula</u>:

$$\text{Fuel Cost Savings} = (X_o - X_n) \times \text{Hourly Fuel Price}$$

Where:

- Hourly Fuel Price is the Steam Price identified in Equation C2-1 in Schedule C. However, for purposes of this Pre-empted Dispatch Payment calculation, the value for the Steam Price will be set to zero for Geysers Main Units until the cumulative Hourly Metered Total Net Generation for the Contract Year from all Units exceeds the Minimum Annual Generation given in Equation C2-2.

<u>For pumped storage hydroelectric Units, the Fuel Cost Savings is calculated by the following formula</u>:

$$\text{Fuel Cost Savings} = (X_o - X_n) \times \text{Hourly Fuel Price}$$

Where:

- Hourly Fuel Price is YTD Pumping Cost / YTD Energy Produced; and YTD Pumping Cost and YTD Energy Produced are as defined in Equation C4-2.

<u>For conventional hydroelectric Units, the Fuel Cost Savings is zero</u>.

Other Savings = $((X_o - X_n)$ x (Variable O&M Rate + applicable annual charge for short-term sales under 18 CFR 382.201 of the FERC Regulations + PX Administration Charge as charged under the PX Tariff))

Emissions Savings = RECLAIM Savings + NOx Emissions Fee Savings + Organic Gases Fee Savings + Sulfur Oxides Fee Savings + Particulate Matter Savings + Carbon Monoxide Fee Savings

RECLAIM Savings = $((AX_o^2+BX_o+C) - (AX_n^2+BX_n+C))$ ✍ RECLAIM NOx Trading Credit Rate

Where:

- A, B and C are the coefficients from Table C1-13;
- X_o = Original Total Schedule in Market and Nonmarket Transactions;
- X_n = New Total Schedule in Market and Nonmarket Transactions;

NOx Emissions Fee Savings = $\dfrac{((AX_o^2+BX_o+C) - (AX_n^2+BX_n+C))}{2000}$ ✍ NO_x Emissions Fee;

Where:

- A, B and C are the coefficients from Table C1-13;
- X_o = Original Total Schedule in Market and Nonmarket Transactions;
- X_n = New Total Schedule in Market and Nonmarket Transactions;

Organic Gases Fee Savings =

> 4.76 ? 10^{-7} ✍ Gas Fuel Savings ✍ Associated Emission Factor for Organic Gases ✍ Associated Emissions Fee for Organic Gases

Sulfur Oxides Fee Savings =

> 4.76×10^{-7} ✍ Gas Fuel Savings ✍ Associated Emission Factor for Sulfur Oxides ✍ Associated Emissions Fee for Sulfur Oxides

Particulate Matter Oxides Fee Savings =

> 4.76×10^{-7} ✍ Gas Fuel Savings ✍ Associated Emission Factor for Particulate Matter ✍ Associated Emission Fee for Particulate Matter

Carbon Monoxide Fee Savings =

> 4.76×10^{-7} × Gas Fuel Savings × Associated Emission Factor for Carbon Monoxide × Associated Emission Fee for Carbon Monoxide

All Emissions Fees and Emission Factors are determined in accordance with Schedule C.

[If applicable, insert emission cost savings formula for fuel other than natural gas.]

The Owner will be entitled to retain all payments received from the Owner's Scheduling Coordinator for the Unit's scheduled output.

B. **For Pre-empted Ancillary Services Market Transactions:**

ISO shall pay Owner the product of (i) the difference between the MW of the Ancillary Service Owner had scheduled to provide in a Market Transaction and the MW of Ancillary Services Owner is able to provide after complying with the Dispatch Notice and (ii) the Market Clearing Price the Owner pays to buy back its commitment to deliver the preempted MW of Ancillary Services (if the Owner actually incurs such a cost), or the penalty the Owner pays for failure to deliver the preempted MW of Ancillary Services (if the Owner actually incurs such a cost) for the applicable Ancillary Service, market, and hour. In addition, if compliance with the Dispatch Notice causes reduction of a market regulation transaction, the ISO shall also pay the Owner the product of the Regulation Energy Payment Adjustment (REPA) amount, if applicable, and the MW of Regulation which Owner had scheduled but is unable to provide because of its compliance with the Dispatch Notice.

Schedule E

Ancillary Services
Part 2 for Condition 2

The ISO may call upon the Unit to provide the following Ancillary Services as defined in the ISO Tariff:

Regulation
Spinning Reserve
Nonspinning Reserve
Replacement Reserve
Voltage Support (including synchronous condenser operation)
Black Start

The Owner shall be required to operate the Unit within the Power Factor range of the Unit specified in Schedule A to provide Voltage Support without additional compensation.
The Owner shall receive no payment for any Ancillary Services Capacity provided. However, operation of a Unit in synchronous condenser mode will be compensated as shown below.

<u>Motoring Charge</u>

When Units are operated as synchronous condensers (i.e., motored using electric power) to provide Ancillary Services, if applicable, the payment for that service is given by the following formula:

Motoring Charge = (Power consumption rate (MWh/hr)) × (hours operated) × (Energy Price)

Where the Power consumption rate is given by the following table:

Unit	Power consumption rate (MWh/hour)

The Energy Price shall be equal to the total power costs charged to the Facility by its supplier of end-use Energy under the Applicable UDC Tariff for the billing cycle in which the Motoring Charge was incurred divided by the total power consumed at the Facility under such tariff during such billing cycle.

Schedule E

Ancillary Services
Part 3 for Black Start Services

For those Units with Black Start capability, the cost of maintaining such capability is included in this Agreement and no additional costs shall be charged to the ISO for maintaining such capability. The ISO will pay for Black Start service, including for a Black Start Test Dispatch Notice, at the rates and prices in this Agreement for Start-Ups and Delivery of Energy in connection with the Black Start service. Owner shall maintain the Black Start capability of the Unit and the Facility and provide Black Starts in accordance with the ISO Ancillary Services Requirements Protocol and the ISO Dispatch Protocol, which shall be deemed incorporated by reference into this Agreement.

When the ISO first gives written notice to the Owner that it has obtained adequate Black Start service through an auction or a separate agreement with Owner or other Generators and Black Start service under this Agreement is no longer required, the ISO shall not be entitled to call upon this Unit to provide Black Start service. Once the ISO has given this notice, the Owner may remove Black Start service from this Agreement by filing unilaterally a change in rate schedule with FERC. Such filing shall not be required to include any reduction in rate or revenue solely because Black Start service is removed. The ISO shall not oppose the absence of any rate or revenue reduction that results solely from removing such service.

Schedule F

Determination of Annual Revenue Requirements
of Must-Run Generating Units

Table of Contents

Article I. Purpose and General Procedures

Part A. Determination of Rates and Charges

This Schedule F establishes the procedures and methodology for determining the Annual Fixed Revenue Requirements (in dollars) and Variable O&M Rates (in $/MWh) for facilities designated for must-run service for purposes of calculating certain charges for such service under the RMR Contract.

The Annual Fixed Revenue Requirements and the Variable O&M Rate for each designated must-run generating facility shall be determined annually. The Annual Fixed Revenue Requirements and the Variable O&M Rate for each such facility that shall be used for calculating charges to the ISO during each calendar year shall be determined by application of the Formula set forth in Article II hereof to the Owner's costs incurred during the twelve-month period ended on June 30 of the prior calendar year. Each twelve-month period ending on June 30 of each year is hereinafter referred to as the "Cost Year" relating to the rates and charges that are effective during the succeeding calendar year.

Part B. Informational Filings

In connection with the determination of rates and charges for each calendar year, reflecting costs incurred during the June 30 Cost Year as described in the foregoing Part A of this Article I, the Owner shall provide to the ISO an Information Package detailing and supporting all calculations involved in such determination. A single Information Package may contain all such informational materials pertaining to all of the Owner's designated must-run facilities. On or before October 1, 2001, the Owner shall provide to the ISO the Information Package relating to the rates and charges to become effective on January 1, 2002. Thereafter, on November 1 of each year, the Owner shall provide to the ISO the Information Package relating to the rates and charges to be effective during the calendar year beginning on the following January 1.

Each such Information Package shall be in a clear and readable format and shall contain:

1. detailed workpapers showing the derivation of costs under the Formula for the relevant Cost Year along with supporting schedules showing the data used in applying the formula, presented in a format consistent with the presentation of information in the FERC Form No. 1;

2. a clear identification of the depreciation rates reflected in claimed costs for the Cost Year and the rate of return and every other stated item (*i.e.*, any item which appears as a numerical value in the Formula and which only may be changed by a filing with the FERC);

3. a comparison of the major components of the resulting revenue requirements for the relevant Cost Year with the corresponding components of the revenue requirements that result from the application of the Formula using costs from the Owner's FERC Form No. 1 relating to the preceding calendar year;

4. such additional documentation as to specific items of costs required by the Formula.

The Owner shall provide each Information Package to the ISO in printed form and a suitable electronic format. The ISO shall post the Information Package on its web site. A suitable electronic format shall be any format that the FERC permits for electronic filings.

Coincident with providing each such Information Package to the ISO, the Owner shall also submit the Information Package to the FERC in an informational filing so as to allow for review of the related rates and charges by the FERC staff and affected parties. As to the informational filing relating to rates and charges to be effective during calendar year 2002, (i) discovery requests by the FERC staff and affected parties shall be made within 45 days of the filing, with responses by the Owner due within 60 days of the filing, and (ii) protests, if any, by affected parties shall be filed with the FERC within 75 days of the filing. As to each subsequent informational filing, (i) discovery requests by the FERC staff and affected parties shall be made within 20 days of the filing, with responses by the Owner due within 35 days of the filing, and (ii) protests, if any, by affected parties shall be filed with the FERC within 45 days of the filing. In the event that the need arises during the discovery process for the nondisclosure or confidentiality of information, the Owner and affected parties, other than FERC Staff and state regulatory agencies, shall utilize the procedures contained in Schedules N-1 and N-2 of the RMR Contract. If the Owner seeks the confidentiality or nondisclosure of information provided to FERC or state regulatory agencies, it shall follow the applicable rules, regulations and statutory provisions of those agencies.

Protests to the Information Package challenging arithmetic calculations or conformity to the Rate Formula, not resolved by summary disposition of the FERC, shall be resolved by the use of the Alternative Dispute Resolution procedures in Schedule K of the RMR contract. In such a proceeding, the Owner will bear the burden of proof as in a proceeding under Section 205 of the Federal Power Act (FPA). If it is found that an erroneous calculation or non-conforming formula element has been used, refunds shall be ordered. The amount of refunds shall restore the parties to the positions they would have occupied had the erroneous calculations or non-conforming formula elements not been used, with interest calculated pursuant to Section 35.19a of the Commission's regulations, 18 C.F.R. Section 35.19a.

If a matter is set for hearing, additional discovery shall be permitted in accordance with the Commission's Rules of Practice and Procedure. Under hearings established pursuant to this provision, refund rights will be as in a proceeding under Section 205 of the FPA. Any refunds due as the result of a final Commission order will be credited or paid to the ISO with interest in accordance with 18 C.F.R. 35.19a.

In addition to the discovery provided above, affected parties shall have the ability to audit the Owner's books and records as provided in Section 12.2 of the RMR Contract. To the extent that an audit discloses that the formula was not correctly applied for a particular year, the affected prior billings shall be corrected, and appropriate refunds or credits shall be provided to the ISO, with interest determined in accordance with 18 C.F.R. 35.19a.

Notwithstanding the above procedures, all parties retain full rights to make filings at any time under Sections 205 and 206 of the FPA, as appropriate.

Article II. Formula for Determination of Annual Revenue Requirements

Part A. Purpose and Overview

The purpose of this Formula For Determination of Annual Revenue Requirements ("Formula") is to specify the method for determining the Annual Revenue Requirements, and certain components thereof, of particular must-run generating units for each Cost Year.

Part B of this Formula contains the specifications for the components of costs that may be included in the Annual Revenue Requirements of individual designated must-run generating units (*i.e.*, for each "Subject Resource").

Part C of this Formula sets forth (i) general instructions for the use and application of the Formula, and (ii) certain general definitions of terms used herein.

Part B. Determination of Annual Revenue Requirements

Section 1. Annual Fixed Revenue Requirements and Variable O&M Rate

(A) Annual Fixed Revenue Requirements

The "Annual Fixed Revenue Requirements" for the Subject Resource is the amount determined as the following difference:

1. Total Annual Revenue Requirements, as defined below; less

2. Total Annual Variable Costs, as defined below.

(B) Variable O&M Rate

The "Variable O&M Rate" for the Subject Resource is the rate (in $/MWh) determined as the follows:

Variable O&M Rate = [Annual Variable O&M Expenses]/[Annual Net Generation]

where "Annual Variable O&M Expenses" is defined hereinbelow, and "Annual Net Generation" is the net generation (in MWh) of the Subject Resource during the Cost Year.

Notwithstanding the foregoing, whenever the Annual Net Generation of the Subject Resource is zero or negative, the Variable O&M Rate shall be deemed to be zero.

(C) Total Annual Revenue Requirements

The "Total Annual Revenue Requirements" for the Subject Resource is the amount that is the sum of the following amounts:

1. Operating Expenses, determined pursuant to Section 2 below; and

2. Return and Income Tax Allowance, determined pursuant to Section 3 below.

Section 2. Operating Expenses

"Operating Expenses" for the Subject Resource is the quantity that is the sum of the following amounts:

1. Total O&M Expenses, as defined below;

2. Depreciation Expenses, as defined below;

3. Taxes Other Than Income Taxes, as defined below; and

4. Revenue Credits, as defined below.

(A) Total O&M Expenses

"Total O&M Expenses" is the amount of expenses arising from the operation and maintenance of the Subject Resource, including Production O&M Expenses, Transmission O&M Expenses, Distribution O&M Expenses, and Administrative & General Expenses, all as defined below.

(1) **Production O&M Expenses:** Expenses incurred directly in operating and maintaining the Subject Resource:

(**a)** **Steam Production O&M:** For steam units only, amounts properly recorded in Accounts 500-515.

(b) **Hydro Production O&M:** For hydro units only, amounts properly recorded in Accounts 535-545.

(c) **Other Power Generation O&M:** For other types of units, amounts properly recorded in Accounts 546-554.

(d) **Other Power Supply Expenses:** Amounts properly recorded in Accounts 555-557, if any, that are reasonably assignable or allocable to the Subject Resource.

(2) **Transmission O&M Expenses:** Expenses incurred directly in operating and maintaining the transmission facilities associated with the Subject Resource, as properly recorded in Accounts 560-573 and reasonably assignable or allocable to the Subject Resource.

(3) **Distribution O&M Expenses:** Expenses incurred directly in operating and maintaining the distribution facilities associated with the Subject Resource, as properly recorded in Accounts 580-598 and reasonably assignable or allocable to the Subject Resource.

(4) **Administrative and General (A&G) Expenses:** Those portions, if any, of administrative and general expenses, as properly recorded in Accounts 920-935, that are reasonably related to the operation of the Subject Resource, determined from appropriate direct assignment or reasonable allocation. Such expenses shall exclude (i) franchise fees related solely to the Owner's retail sales, (ii) retail regulatory expenses, (iii) assessments under 18 CFR Section 382.201 of the FERC Regulations, (iv) association dues, and (v) general advertising expenses.

Notwithstanding the foregoing, O&M Expenses hereunder shall exclude all PX Administration charges as charged under the PX Tariff, irrespective of in which Account or Accounts such charges are included.

(B) **Depreciation Expenses**

"Depreciation Expenses" are provisions for depreciation and amortization for the Subject Resource, as properly recorded in Accounts 403, 404, 405, 406, and 407, including only:

(1) **Production Plant Depreciation:** Depreciation and amortization, if any, of investment in the Subject Resource;

(2) **Transmission Plant Depreciation:** Depreciation and amortization, if any, of investment in the transmission facilities associated with the Subject Resource, as reasonably assignable or allocable to the Subject Resource;

(3) **Distribution Plant Depreciation:** Depreciation and amortization, if any, of investment in the distribution facilities associated with the Subject Resource, as reasonably assignable or allocable to the Subject Resource;

(**4)** **General and Intangible Plant Depreciation:** Depreciation and amortization, if any, of general and intangible plant investments that are reasonably assignable or allocable to the Subject Resource.

Notwithstanding the foregoing, costs recorded in Accounts 405, 406 and 407 shall be included hereunder only if, and to the extent that, FERC shall have permitted the inclusion of such costs for ratemaking purposes for the Owner under the RMR Contract.

(C) Taxes Other Than Income Taxes

"Taxes Other Than Income Taxes" are taxes other than income and revenue taxes, as properly recorded in Account 408.1, that are reasonably assignable and allocable to the Subject Resource, including for example:

1. Property and Property-Related Taxes;

2. Payroll and Labor-Related Taxes;

3. Other Taxes, if any, identifiable as reasonably assignable or allocable to the Subject Resource.

Taxes Other Than Income Taxes assignable and allocable to the Subject Resource shall not include any taxes related solely to, or arising solely from, the Owner's retail sales.

(D) Revenue Credits

"Revenue Credits" are those revenues, if any, that are (i) properly recorded in Account 451 (Miscellaneous Service Revenues), Account 453 (Sales of Water and Water Power), Account 454 (Rent From Electric Property), Account 455 (Interdepartmental Sales), and Account 456 (Other Electric Revenues), and (ii) directly related to, or reasonably allocable to, the Subject Resource. Such Revenue Credits shall be treated as negative values hereunder.

(E) Treatment of Capital Leases

The foregoing components of Operating Expenses may include expenses associated with capital leases as approved by the Commission, as set forth more fully under Article II, Part B, Section 4(A) of this Formula.

Section 3. Return and Income Tax Allowance

"Return and Income Tax Allowance" is the quantity that is the sum of:

1. the product of:

   a. Allowable Pre-Tax Rate of Return, and

   b. Net Investment,

   as both such quantities are hereinafter defined; and

2. the quantity equal to:

[ITC Amortization]/(1-t)

where:

a. "t" is the effective, combined state and federal income tax rate.

b. "ITC Amortization," is amortization, if any, of investment tax credits, as properly recorded in Account 411.4, that are reasonably assignable or allocable to the Subject Resource and to those portions of general and intangible plant investments that are reasonably assignable or allocable to the Subject Resource. Notwithstanding the foregoing, this term shall include only those amounts of amortization of investment tax credits which the Owner shall have elected to receive under Section 46(f)(1) of the Internal Revenue Code. ITC Amortization amounts that reduce net income shall be treated as negative values hereunder, while ITC Amortization amounts, if any, that increase net income shall be treated as positive values hereunder.

Section 4. Net Investment

"Net Investment" is the quantity that is determined as follows:

Net Investment = Gross Plant Investment - Depreciation Reserve + CWIP
+ PHFU - ADIT + Working Capital

where the quantities appearing in the foregoing equation are defined hereinafter below.

In determining Net Investment hereunder, each component thereof, other than Cash Allowance, shall be determined as the end-of-year balances in the Accounts specified for the relevant Cost Year.

(A) Gross Plant Investment

"Gross Plant Investment" is gross original cost plant investment as properly recorded in Accounts 101, 102, 106, and 114, including only the following amounts:

(1) Production Plant Investment: investment in the generating unit itself and in common facilities associated with the unit, as recorded in Accounts 310-316, 330-336, or 340-346, 106 and 114;

(2) Transmission Plant Investment: investment in transmission facilities associated with the Subject Resource, as properly recorded in Accounts 350-359, 106, and 114, and reasonably assignable or allocable to the Subject Resource;

(3) Distribution Plant Investment: investment in distribution facilities associated with the Subject Resource, as properly recorded in Accounts 360-373, 106, and 114, and reasonably assignable or allocable to the Subject Resource; and

(4) General and Intangible Plant Investment: reasonably assignable and allocable portions, if any, of general and intangible plant investment, recorded in Accounts 389-399 and 301-303, 106 and 114.

Subject to the limitations detailed in this paragraph, when the Owner has a capital lease in lieu of gross plant investment, it may include Account 101.1 hereunder. A lease may be capitalized and the costs included for ratemaking purposes if the Owner demonstrates that the lease qualifies as a capital lease under 18 C.F.R. Part 101, General Instruction No. 19 (1998), and the Owner has obtained, prior to the informational filing, approval to include such costs for ratemaking purposes from the FERC under the FPA. Capital leases shall be accounted for in accordance with 18 C.F.R. Part 101, General Instruction No. 20 (1998).

(B) Depreciation Reserve

"Depreciation Reserve" is accumulated provision for depreciation and amortization, as properly recorded in Accounts 108, 111, and 115, related to the Subject Resource, including the following amounts:

(1) Production Plant Depreciation Reserve: amounts of Depreciation Reserve for the investment in the unit itself and in common facilities associated with the unit;

(2) Transmission Plant Depreciation Reserve: amounts of Depreciation Reserve for the investment in transmission facilities associated with the Subject Resource, as reasonably assignable or allocable to the Subject Resource;

(3) Distribution Plant Depreciation Reserve: amounts of Depreciation Reserve for the investment in distribution facilities associated with the Subject Resource, as reasonably assignable or allocable to the Subject Resource;

(4) General and Intangible Plant Reserve: amounts of Depreciation Reserve for the portions, if any, of general and intangible plant investments reasonably assignable and allocable to the Subject Resource.

Credit balances in the aforementioned accounts shall be treated as positive values hereunder, and debit balances in such accounts shall be treated as negative values.

(C) CWIP

"CWIP" is the amount of construction work in progress, as properly recorded in Account 107 for construction projects associated with the Subject Resource related solely and directly to pollution control for the Subject Resource.

(D) PHFU

"PHFU" is the cost of plant held for future use, as properly recorded in Account 105 that is reasonably assignable or allocable to the Subject Resource.

(E) ADIT

"ADIT" is accumulated provision for deferred income taxes, as properly recorded in Accounts 190, 281, 282, 283, and 255, that are reasonably assignable or allocable to the investment in, or operation of, the Subject Resource, including the following amounts:

(1) Production Plant ADIT: amounts of ADIT arising directly from the investment in, or operation of, the Subject Resource itself and common facilities associated with the Subject Resource;

(2) Transmission Plant ADIT: amounts of ADIT arising directly from the investment in, or operation of, the transmission facilities, if any, associated with the Subject Resource;

(3) **Distribution Plant ADIT:** amounts of ADIT arising directly from the investment in, or operation of, distribution facilities, if any, associated with the Subject Resource; and

(4) **General and Intangible Plant ADIT:** amounts of ADIT arising from the portions, if any, of general and intangible plant investments reasonably assignable and allocable to the Subject Resource.

For purposes of this Formula, ADIT means accumulated provision for deferred income taxes, as properly recorded in the aforementioned Accounts, *including* amounts previously recorded in such accounts and reclassified as a result of the adoption of SFAS No. 109, but *excluding* amounts recorded in such accounts as a result of the adoption of SFAS No. 109, such that the required adoption of SFAS No. 109 will have no effect on the costs determined hereunder.

Notwithstanding the foregoing, as to Account 255, ADIT hereunder shall include only those amounts, if any, related to investment tax credits which the Owner shall have elected to receive under Section 46(f)(2) of the Internal Revenue Code.

ADIT balances that are credit balances shall be treated as positive values hereunder, while ADIT balances that are debit balances shall be treated as negative values hereunder.

Owner shall support all amounts of ADIT included and not included hereunder in the manner described in sections 35.13(h)(6) and (7) of the Commission's regulations (Statements AF and AG, respectively), except that the time period for the relevant data for the informational package will be consistent with the requirements of this formula, rather than the "Periods" referenced in those regulations.

(F) Working Capital

"Working Capital" is the sum of the portions, if any, of the following items that are reasonably assignable or allocable to the Subject Resource:

(1) **Fuel Stocks,** which is the amount of fossil fuel stock, if any, maintained for the Subject Resource, as properly recorded in Account 151;

(2) **Plant Materials and Supplies,** consisting of the value of plant materials and supplies reasonably assignable or allocable to the Subject Resource, as properly recorded in Accounts 154 and 163;

(3) **Prepayments,** consisting of the amount, if any, of prepayments reasonably assignable or allocable to the Subject Resource, as properly recorded in Account 165;

(4) **Working Cash Allowance,** which is one-eighth of O&M Expenses (as defined herein), less (a) Total Annual Fuel Costs (as defined hereinbelow), and (b) all amounts or portions, if any, of Account 555 (Purchased Power) that may be included in such O&M Expenses; and

Unamortized Deferred Costs, which shall be that portion, if any, of Account 186 directly related to, or reasonably allocable to, the Subject Resource.

Section 5. Allowable Pre-Tax Rate of Return

The Allowable Pre-Tax Rate of Return shall be the sum of:

(a) 12.25%, and

(b) 30% of the amount, if any, by which (a) the latest available 6-month average of yields on 10-year U.S. Treasury Bonds, as of the date of the first Informational Filing, exceeds (b) the latest available 6-month average of yields on 10-year U.S. Treasury Bonds as of *[the effective date of the settlement]*.

Notwithstanding the foregoing, the Owner may make application to the FERC, prior to or in conjunction with the first Informational Filing, in a limited proceeding to seek to establish a different Allowable Pre-Tax Rate of Return under Section 205 of the Federal Power Act.

Section 6. Additional Quantities

(A) Annual Variable O&M Expenses

"Annual Variable O&M Expenses" is the sum of the following quantities:

(1) Variable Production O&M Expenses: those portions of Production O&M Expenses, as defined above, other than fuel expenses, that are reasonably determined to be variable expenses, in the sense that they are incurred as a result of, or otherwise are reasonably associated with, the production of energy by the Subject Resource.

(2) Variable A&G Expenses: that portion of A&G Expenses that is related or allocable to the foregoing Variable Production O&M Expenses.

Notwithstanding the foregoing, starting with the first information filing hereunder and continuing until the Owner elects to use a different method to determine its Annual Variable O&M Expenses, the Owner may compute Annual Variable O&M Expenses as the amount equal to the product of (a) the Initial Variable O&M Rate, in $/MWh, for the Subject Resource, as set forth in Exhibit A hereto (Exhibit A can be found in Appendix B to the Stipulation and Agreement), times (b) the Net Generation of the Subject Resource (as defined hereinabove). Whenever the Owner does not compute Annual Variable O&M Expenses based on the Initial Variable O&M Rate in the foregoing manner, the Owner shall include in each of Informational Package a detailed explanation of the method or methods used to classify O&M expenses as between fixed (*i.e.*, capacity-related) expenses and variable (*i.e.*, energy-related) expenses and the reason(s) such method results in just and reasonable rates.

(B) Annual Fixed O&M Expenses

"Annual Fixed O&M Expenses" is the quantity that is equal to the following:

(1) Total O&M Expenses, as defined hereinabove, less

(2) the sum of:

a. Annual Variable O&M Expenses, as defined hereinabove, and

b. Annual Variable Fuel Costs, as defined hereinbelow,

c. Annual Emissions Costs, as defined hereinbelow, and

d. Annual Non-Fuel Start-Up Costs, as defined hereinbelow.

(C) Fuel Expenses

(1) Total Annual Fuel Costs

"Total Annual Fuel Costs" is the total fuel expense for the Subject Resource for the Cost Year properly recorded in Account 501 or Account 547, as appropriate depending on the nature of the Subject Resource.

(2) Annual Fixed Fuel Costs

"Annual Fixed Fuel Costs" is that portion, if any, of Total Annual Fuel Costs related to fuel handling and administration of fuel planning, procurement and transportation which do not vary with the amount of fuel purchased.

(3) Annual Variable Fuel Costs

"Annual Variable Fuel Costs" is the quantity that is the following difference:

1. Total Annual Fuel Costs, less

2. Annual Fixed Fuel Costs.

(D) Annual Emissions Costs

"Annual Emissions Costs" is the total emissions costs that are related to the operation of the Subject Resource during the Cost Year.

(E) Annual Non-Fuel Start-Up Costs

"Annual Non-Fuel Start-Up Costs" is the aggregate sum of costs, other than fuel costs, attributable to start-ups of the Subject Resource during the Cost Year, consisting of start-up power costs, shut-down power costs, and other non-fuel start-up costs, all as determined pursuant to the applicable sections of Schedule D of the RMR Contract, as applied to all start-ups of the Subject Resource during the Cost Year.

(F) Total Annual Variable Costs

"Total Annual Variable Costs" is the sum of:

1. Annual Variable O&M Expenses,

2. Annual Variable Fuel Costs, and

3. Annual Emissions Costs.

Part C. General Instructions and Explanatory Notes

Section 1. General Instructions

In applying this Formula to a Subject Resource, the following instructions and explanations shall be followed:

(A) No Duplicative Charges

The costs determined and referenced by this Formula shall exclude costs that are recoverable, or that are actually recovered, elsewhere under the applicable contract or agreement between the Owner and the ISO. There shall be no double counting of costs hereunder.

(B) Determination of Depreciation Expenses

Depreciation Expenses, Depreciation Reserve, and Deferred Income Taxes reflected in the revenue requirements determined pursuant to this Formula shall be computed using either fixed depreciation rates or depreciation rates determined annually from fixed mortality characteristics (i.e., service lives, net salvage ratios, etc.). Such depreciation rates and/or mortality characteristics, which may differ for particular assets or groups of assets comprising, or related to, the Subject Resource, are set forth on Exhibit B, which is attached hereto and made a part hereof. Such depreciation rates and/or mortality characteristics may not be changed except pursuant to Section 205 or Section 206 of the FPA. Nothing herein shall be construed as affecting any requirements of the FERC regarding the use by the Owner of depreciation rates for financial reporting purposes.

(C) Costs in Excess of Original Cost

The components of rate base and the costs reflected under the Formula shall not include an acquisition adjustment or costs associated with an acquisition adjustment unless the Owner shall have obtained approval from the FERC to include under the Formula such an adjustment or such costs for ratemaking purposes under the FPA. The effective date for the inclusion of such costs shall be as set forth in the FERC order.

(D) Use of FERC Accounting

The costs determined and referenced by this Formula shall reflect only FERC-basis accounting, and shall not reflect any accounting for costs approved by any state regulatory commission or other body if not approved or accepted by the FERC for use in connection with the RMR Contract. Except as otherwise provided herein, the accounting for costs for purposes of applying this Formula shall be consistent with the requirements of the Uniform System of Accounts.

(E) Accounting Methods

The costs determined and referenced by this Formula shall reflect only such accounting methods prescribed by such authorities as AICPA and FASB that shall have been approved or accepted by the FERC for use in connection with the RMR Contract. The Owner shall be required to seek and gain such approval or acceptance from the FERC prior to reflecting any changed accounting methods in the determination of costs in connection with this Formula.

The Owner shall carry the burden of demonstrating that its accounting methods and entries reflected in the costs determined and referenced by this Formula produce just, reasonable, and nondiscriminatory rates for its customers.

(F) Out-of-Period Adjustments

The costs determined and referenced by this Formula shall not reflect any accounting entries the purpose of which is to adjust or correct for accounting entries in years other than the Cost Year if such adjusting or correcting entries would have an unjust, unreasonable, or discriminatory effect on the ISO.

(G) Extraordinary Costs

Extraordinary costs included in the costs determined and referenced by this Formula shall be subject to amortization over a reasonable period of time. In determining how costs should be amortized, the parties shall also determine how the costs being amortized should be recovered in the event that the plant closes and does not reopen.

As used herein, "extraordinary costs" mean costs arising from events and transactions that are of an unusual nature and infrequent occurrence, the effects of which are abnormal and significantly different from the ordinary and typical activities of the Owner, and would not reasonably be expected to recur in the foreseeable future. In determining significance, items should be considered individually and not in the aggregate. However, the effects of a series of related transactions arising from a single specific and identifiable event or plan of action should be considered in the aggregate. An item can be extraordinary even if it is less than five (5) percent of income computed before the extraordinary item. In its annual Information Package, the Owner shall identify and provide explanations for all extraordinary costs which it seeks to include in the rates and charges determined pursuant to this Formula, and the Owner shall bear the burden of proof, as in a proceeding under Section 205 of the FPA, that its proposed treatment of extraordinary costs is just and reasonable.

(H) Imprudently Incurred Costs

The costs determined and referenced by this Formula shall not include any costs which have been determined by the FERC in a proceeding under Section 206 of the FPA to have been imprudently incurred by the Owner.

(I) Transmission Cost Assignments and Allocations

Costs of transmission facilities assigned and/or allocated to the Subject Resource hereunder are intended to include only those costs, if any, related to the step-up substation facilities and other transmission facilities directly connected to the Subject Resource and used to deliver the output of the Subject Resource to the transmission grid. In each annual Informational Package, the Owner shall clearly identify and fully describe all transmission facilities which it claims satisfy the foregoing criteria.

(J) Distribution Cost Assignments and Allocations

Costs of distribution facilities assigned and/or allocated to the Subject Resource hereunder are intended to include only those costs, if any, related to the step-up substation facilities and other distribution facilities directly connected to the Subject Resource and used to deliver the output of the Subject Resource to the transmission or distribution system. In each annual Informational Package, the Owner shall clearly identify and fully describe all distribution facilities which it claims satisfy the foregoing criteria.

(K) Inclusion of Certain Costs

The Owner shall include in its annual Informational Package detailed workpapers and explanations supporting the reasonableness of including in the revenue requirements determined pursuant to this formula any amounts recorded in Accounts 501, 547, 555, 561, 927, 105, and 186. The Owner shall bear the burden of proof, as in a proceeding under Section 205 of the FPA, to affirmatively demonstrate that all such included amounts are directly related to the provisions of service under the RMR Contract and are reasonably assignable or allocable to the Subject Resource. As to Account 105, the requirement for a definitive plan required by the description of Account 105 in the Uniform System of Accounts, and the affirmative demonstration required by this paragraph, shall be deemed to be met upon a showing that the ISO has approved, in accordance with the provisions of Section 7.4 of the RMR Contract, a plan for the future use of the property.

(L) Direct Assignments and Allocations

Where Part B of this Formula provides for the identification and/or assignment of costs incurred directly in connection with a particular facility or facilities (including a Subject Resource), or directly related to such a facility or facilities, the Owner shall bear the burden of demonstrating the reasonableness of each such identification and/or assignment, and each failure to make such an identification and/or assignment. Notwithstanding the foregoing, where this Formula provides for such a direct identification or assignment of costs, the Owner may use an allocation method to apportion such costs among particular facilities; provided, however, that (i) the Owner shall in its Informational Package clearly identify and describe such allocation method and the basis for it, and (ii) the Owner shall bear the burden of demonstrating the reasonableness of the method. It is recognized that such allocation methods may, for example, be appropriate for apportioning certain types of costs between individual generating units at a multi-unit generating station. Such allocations of costs between individual generating units at a plant site shall be consistent with the requirements for such allocations, if any, provided in the RMR Contract.

(M) No Adverse Distinction

In applying this Formula and in maintaining its books and records insofar as they affect the results of applying this Formula, the Owner shall not make an adverse distinction between the Subject Resource and any other facility or facilities owned or operated by the Owner; *e.g.*, the Owner shall assign certain costs directly to the Subject Resource only if, and to the extent that, the Owner directly assigns such costs to other, similar facilities.

Section 2. General Definitions

Except as may be expressly stated otherwise, the following terms have the followings meanings as used herein:

(A) Account

"Account" refers to a particular account for "major" utilities as prescribed by the Uniform System of Accounts.

(B) FERC

"FERC" means the Federal Energy Regulatory Commission or its successor.

(C) Uniform System of Accounts

"Uniform System of Accounts" means the FERC's "Uniform System of Accounts Prescribed For Public Utilities and Licensees Subject to the Provisions of the Federal Power Act," as such uniform system of accounts was in effect as of the first effective date of the RMR Contract.

(D) RMR Contract

"RMR Contract" means the contract to which this Formula is attached and made a part thereof.

(E) Subject Resource

"Subject Resource" means any particular generating unit to which this Formula is applied for purposes of determining the annual costs thereof.

(F) Cost Year

"Cost Year" means the twelve-month period ended June 30 to which this Formula is applied to determine the Annual Fixed Revenue Requirements and Variable O&M Rate for a Subject Resource to be applicable during the next succeeding calendar year.

(G) Owner

"Owner" means the entity, other than the ISO, that is a party to the RMR Contract.

(H) ISO

The "ISO" means the California Independent System Operator Corporation.

Exhibit A - Initial Variable O&M Rates[9]

Line	RMR Facility	Unit	Initial Variable O&M Rate ($/MWh)

[9] Exhibit A for each owner is filed in Appendix to the Stipulation and Agreement.

Exhibit B - Depreciation Rate and Mortality Characteristics[10] [11]

Line	RMR Facility	Unit	Plant Account	Depreciation Rate (%)	Mortality Characteristics			
					Retire-ment Date	Average Service Life	Salvage Value or Rate	Interim Retire-ments Rate

[10] Exhibit B for each owner is filed in Appendix B to the Stipulation and Agreement.
[11] Effective as of the effective date of the Settlement.

Exhibit C - 1998 Cost Information

Pursuant to Article IV.E of the Stipulation and Agreement filed with the FERC on April 2, 1999, the Owner shall file with the FERC in Docket No. ER98-441-000, et. al., a superceding Exhibit C, setting forth the following information for each unit for the period ending December 31, 1998:

(1) Name of the facility and unit;

(2) Gross Plant In Service, *i.e.* the original cost plus plant additions minus retirements, by major plant function (*i.e.* production, transmission, distribution and general);

(3) Net Plant In Service Gross Plant, *i.e.* gross plant minus depreciation reserve, by major plant function;

(4) Rate Base, *i.e.* net plant and other components of Net Investment as defined in the Formula, such as working capital, Accumulated Deferred Income Taxes (ADIT), etc.

This Exhibit C shall be for informational purposes only and shall be initially filed with FERC by June 1, 1999.

Schedule G

Charge for Service in Excess of Contract Service Limits

Payment for service in excess of the Maximum Annual MWh, Maximum Annual Service Hours or Maximum Annual Start-ups shall be determined in accordance with Option A or Option B. Payment for service from hydroelectric Units in excess of the Maximum Monthly MWh shall be determined in accordance with Option A only. Owner shall make a one-time election between Option A or Option B. Owner must choose Option A for both Billable MWh and Start-ups or Option B for both Billable MWh and Start-ups. This election shall be applicable to all of the Owner's Units under this Agreement and all other Reliability Must-Run Units subject to a "reliability must-run contract" as defined in the ISO Tariff with Owner or any of its affiliates as defined in 18 C.F.R. Section 161.2.

1. Option A

A. For all Billable MWh Delivered after the Counted MWh for the Contract Year equals the Maximum Annual MWh, the Counted Service Hours equals the Maximum Annual Service Hours or, for hydroelectric Units, the Counted MWh for the Month equals the Maximum Monthly MWh ("Schedule G Billable MWh"):

<u>Fossil Fuel Units</u>

In addition to the Variable Cost Payment computed in accordance with Schedule C, the ISO shall pay the Option A Variable Cost Payment, which shall be calculated in accordance with Equation G-1:

Equation G-1

$$\text{Option A Variable Cost Payment} = \frac{0.5 \times (\text{Variable Cost Payment for the Billing Month})}{\text{Billable MWh for the Billing Month}} \times \text{Schedule G Billable MWh}$$

<u>Pumped Storage Hydroelectric Facilities</u>

In addition to the Variable Cost Payment computed in accordance with Schedule C, ISO shall pay the product of (a) the Schedule G Billable MWh, (b) 0.5, and (c) YTD Pumping Costs divided by YTD Energy Produced as computed in accordance with Equation C4-2 in Schedule C.

<u>Conventional Hydroelectric Facilities</u>

In addition to the Variable Cost Payment computed in accordance with Schedule C, ISO shall pay the sum of the products for each hour in the Billing Month of (a) the Hourly Fuel Price for natural gas for the hour calculated in accordance with Equation C1-8 of Schedule C, (b) 12,000 Btu/kWh, (c) the Schedule G Billable MWh for that hour, and (d) 0.5.

B. For all Service Hours provided after the Counted Service Hours for the Contract Year equals the Maximum Annual Service Hours.

Synchronous Condensers

In addition to the Motoring Charge computed in accordance with Schedule E, ISO shall pay the product of (a) the Motoring Charges calculated in accordance with Schedule E, and (b) 0.5.

C. For all Start-ups required to comply with a Dispatch Notice after the Counted Start-ups for the Unit equals the Maximum Annual Start-ups ("Schedule G Start-ups"), the ISO shall pay :

Fossil Fuel Units and Geothermal Units

Two times (a) the Start-up Payment computed in accordance with Equation D-1 in Schedule D, or (b) if the Schedule G Start-up is initiated under a Dispatch Notice but is not successfully completed because it is canceled or rescinded by the ISO, the Start-up Payment for Canceled Start-up is computed in accordance with Equation D-4 in Schedule D.

Conventional Hydroelectric Facilities and Units Capable Only of Synchronous Condenser Operation

The Start-up Payment computed in accordance with Schedule D, plus (a) (0.00338) * the Unit's Annual Fixed Revenue Requirement stated in Section 7 of Schedule B, divided by (b) the Unit's Maximum Annual Start-ups.

Pumped Storage Hydroelectric Facilities

The Start-up Payment computed in accordance with Equation D-1 in Schedule D, plus (a) 0.00167 * the Unit's Annual Fixed Revenue Requirement stated in Section 7 of Schedule B), divided by (b) the Unit's Maximum Annual Start-ups.

2. Option B

A. For all Schedule G Billable MWh Delivered in the Billing Month, the ISO shall pay the Variable Cost Payment computed in accordance with Schedule C. Since Schedule G Billable MWh are included in calculating the Variable Cost Payment for Billable MWh for the Billing Month under Schedule C, there is no additional payment for Schedule G Billable MWh under Option B.

B. For all Service Hours provided after the Counted Service Hours for the Contract Year equals the Maximum Annual Service Hours:

Synchronous Condensers

In addition to the Motoring Charge computed in accordance with Schedule E, ISO shall pay the product of (a) the Motoring Charges calculated in accordance with Schedule E, and (b) 0.5.

C. For all Schedule G Start-ups in the Billing Month, the ISO pay:

Units Capable Only of Synchronous Condenser Operation

The Start-up Payment computed in accordance with Schedule D, plus (a) (0.00338) * the Unit's Annual Fixed Revenue Requirement stated in Section 7 of Schedule B, divided by (b) the Unit's Maximum Annual Start-ups.

Fossil Fuel Units and Geothermal Units

Three times (a) the Start-up Payment computed in accordance with Equation D-1 in Schedule D, or (b) if the Schedule G Start-up is initiated under a Dispatch Notice but is not successfully completed because it is canceled or rescinded by the ISO, the Start-up Payment for Canceled Start-up is computed in accordance with Equation D-4 in Schedule D.

3. Owner's Election

Option A _____

Option B _____

Schedule H

Fuel Oil Service

The following is a description of existing capability of the Facility to burn fuel oil in lieu of or addition to natural gas:

Schedule I

Insurance Requirements

Owner - Obtained Insurance

Commercial General Liability
Commercial general liability insurance covering personal injury and property damage to third parties in connection with the activities at the Facility. The coverage will have a limit of not less than $________________ per occurrence, and will include coverage for sudden and accidental pollution losses. The ISO will be added as an additional insured under the terms of this coverage to the per-occurrence limit above.

Property
Property Insurance for direct physical loss or damage to the Facility, in an amount not less than the probable maximum loss at the Facility.

ISO – Obtained Insurance

Errors and Omissions Insurance and Directors & Officers Insurance
Errors and omissions insurance and directors and officers insurance coverage will have a combined limit of not less than $150 million for the shorter of (i) until the termination of this Agreement or (ii) until January 1, 2002.

Schedule J

Notices

Owner

Name:
Title:
Address:
Telephone:
Facsimile:
E-mail:

With a copy to: Owner's Representative:

ISO:

Debi Le Vine, Director of Contracts and Compliance
California ISO Corp.
151 Blue Ravine Road
Folsom, CA 95630
Facsimile: (916) 351-2487

With a copy to:

Charles F. Robinson, Esq., General Counsel and Vice President
California ISO Corp.
151 Blue Ravine Road
Folsom, CA 95630
Facsimile: (916) 351-2310

With a copy to:

Brian Theaker
Manager of Operations Engineering
California ISO Corp.
151 Blue Ravine Road
Folsom, CA 95630
Facsimile: (916) 351-2264

SCHEDULE K

DISPUTE RESOLUTION

Applicability

1.1 General Applicability.

Except as limited below or otherwise as limited by law (including the rights of any party to file a complaint with FERC under the relevant provisions of the Federal Power Act (FPA)), these ADR Procedures shall apply to (a) all disputes between parties which arise under this Agreement and (b) disputes between ISO and a Responsible Utility relating to a Responsible Utility Invoice, “Final Estimated RMR Invoice, Final Adjusted RMR Invoice” as defined in the ISO Tariff, or RMR Charge or RMR Refund as defined in Annex 1 of the Settlement and Billing Protocol in the ISO Tariff. The foregoing shall not impair the applicability of the ISO Tariff ADR procedures to other disputes between the parties that do not arise under this Agreement. All alternative dispute resolution proceedings hereunder shall be administered by the American Arbitration Association (“AAA”). The Owner, Responsible Utility and the ISO shall enter into such arrangements with the AAA as are necessary to provide for AAA administration of this Schedule K.

1.1.2 This Schedule K shall not apply to disputes as to whether rates and charges under the Agreement are just and reasonable under the Federal Power Act except as provided in Schedule F. Nothing herein shall limit the right of the FERC to initiate or adjudicate complaints or other proceedings in accordance with applicable statutes or regulations or to compel FERC to exceed its statutory authority as defined by any applicable federal statutes, regulations or orders lawfully promulgated thereunder.

1.2 Disputes Involving Government Agencies.

If a party to a dispute is a government agency the procedures herein which provide for the resolution of claims and arbitration of disputes are subject to any limitations imposed on the agency by law, including but not limited to the authority of the agency to effect a remedy. If the governmental agency is a federal entity, the procedures herein shall not apply to disputes involving issues arising under the United States Constitution.

1.3 Injunctive and Declaratory Relief.

Where the court having jurisdiction so determines, use of the ADR Procedures shall not be a condition precedent to a court action for injunctive relief nor shall the provisions of California Code of Civil Procedure sections 1281 *et seq.* apply to such court actions.

1.4 Negotiation and Mediation.

1.4.1 Negotiation.

ISO, Responsible Utility and Owner (“Parties”) shall make good-faith efforts to negotiate and resolve any dispute between them arising under this Agreement prior to invoking the ADR Procedures herein. Each Party shall designate an individual with authority to negotiate the matter in dispute to participate in such negotiations. The Responsible Utility may participate in the ADR proceedings arising under this Agreement to the extent the dispute involves billing or payment obligations, in which case ISO or the Responsible Utility, but not both shall be the disputing party. In addition, to the extent Article 7 or other provisions of this Agreement provide the Responsible Utility third-party beneficiary rights,

the Responsible Utility may also participate in the ADR as a Party.
The Owner may participate in the ADR proceedings relating to a Responsible Utility Invoice, "Final Estimated RMR Invoice, Final Adjusted RMR Invoice" as defined in the ISO Tariff or RMR Charge or RMR Refund as defined in Annex 1 of the Settlement and Billing Protocol, in which case, ISO or the Owner, but not both, shall be the disputing party. In addition, to the extent the ISO Tariff provides the Owner third-party beneficiary rights, the Owner may also participate in the ADR as a Party.

1.4.2 Statement of Claim.

In the event a dispute is not resolved through such good-faith negotiations, any party may submit a statement of claim, in writing, to each other disputing party, which submission shall commence the ADR Procedures. The statement of claim shall set forth in reasonable detail (i) each claim, (ii) the relief sought, including the proposed award, if applicable, (iii) a summary of the grounds for such relief and the basis for each claim, (iv) the parties to the dispute, and (v) the individuals having knowledge of each claim. The other parties to the dispute shall similarly submit their respective statements of claim within 14 days of the date of the initial statement of claim or such longer period as the AAA may permit following an application by the responding party. If any responding party wishes to submit a counterclaim in response to the statement of claim, it shall be included in such party's responsive statement of claim. No party shall be considered as having received notice of a claim decided or relief granted by a decision made under these procedures unless the statement of claim includes such claim or relief.

1.4.3 Selection of Mediator.

After submission of the statements of claim, the parties may request mediation, if the disputing parties so agree. If the parties agree to mediate, the AAA shall distribute to the parties by facsimile or other electronic means a list containing the names of at least seven prospective mediators with mediation experience, or with technical or business experience in the electric power industry, or both, as he or she shall deem appropriate to the dispute. The parties shall either agree upon a mediator from the list provided or from any alternative source, or alternate in striking names from the list with the last name on the list becoming the mediator. The first party to strike off a name from the list shall be determined by lot. The parties shall have seven days from the date of receipt of the AAA's list of prospective mediators to complete the mediator selection process and appoint the mediator, unless the time is extended by mutual agreement. The mediator shall comply with the requirements of Section 1.5.2.

1.4.4 Mediation.

The mediator and representatives of the disputing parties, with authority to settle the dispute, shall within 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 WSCC technical advisory panel) for resolution or an advisory opinion, or referring the dispute directly to FERC.

1.4.5 Demand for Arbitration.

If the disputing parties have not succeeded in negotiating a resolution of the dispute within 30 days of the initial statement of claim or, if within that period the parties agreed to mediate, within 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.

1.5 Arbitration.

1.5.1 Selection of Arbitrator.

1.5.1.1 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 AAA, within 14 days following submission of the demand for arbitration. If the disputing parties cannot agree upon an arbitrator within the stated time, they shall take turns striking names from the list of proposed arbitrators. The first party to strike off a name shall be determined by lot. This process shall be repeated until one name remains on the list, and that individual shall be the designated arbitrator.

1.5.1.2 Disputes of $1,000,000 or Over. Where the total amount of claims and counterclaims in controversy is $1,000,000 or more (exclusive of interest and costs), the disputing parties may agree on any person to serve as a single arbitrator, or shall endeavor in good faith to agree on a single arbitrator from a list of ten qualified individuals provided by the AAA, 14 days following submission of the demand for arbitration. If the disputing parties are unable to agree on a single arbitrator within the stated time, the party or parties demanding arbitration, and the party or parties responding to the demand for arbitration, shall each designate an arbitrator. Each designation shall be from the AAA list of arbitrators, as applicable, no later than the tenth day thereafter. The two arbitrators so chosen shall then choose a third arbitrator.

1.5.2 Disclosures Required of Arbitrators.

The designated arbitrator(s) shall be required to disclose to the parties any circumstances that might preclude him or her from rendering an objective and impartial determination. Each designated arbitrator shall disclose:

1.5.2.1 Any direct financial or personal interest in the outcome of the arbitration;

1.5.2.2 Any information required to be disclosed by California Code of Civil Procedure Section 1281.9.; and

1.5.2.3 Any existing or past financial, business, professional, or personal interest that are likely to affect impartiality or might reasonably create an appearance of partiality or bias. The designated arbitrator shall disclose any such relationships that he or she personally has with any party or its counsel, or with any individual whom they have been told will be a witness. They should also disclose any such relationship involving members of their families or their current employers, partners, or business associates. All designated arbitrators shall make a reasonable effort to inform themselves of any interests or relationships described above. The obligation to disclose interests, relationships, or circumstances that might preclude an arbitrator from rendering an objective and impartial determination is a continuing duty that requires the arbitrator to disclose, at any stage of the arbitration, any such interests, relationships, or circumstances that arise, or are recalled or discovered.

1.5.2.4 If, as a result of the continuing disclosure duty, an arbitrator makes a disclosure which is likely to affect his or her partiality, or might reasonably create an appearance of partiality or bias or if a party independently discovers the existence of such circumstances, a party wishing to object to the continuing use of the arbitrator must provide written notice of its objection to the other parties within ten days of receipt of the arbitrator's disclosure or the date of a party's discovery of the circumstances giving rise to that party's objection. Failure to provide such notice shall be deemed a waiver of such objection. If a party timely provides a notice of objection to the continuing use of the arbitrator the parties shall attempt to agree whether the arbitrator should be dismissed and replaced in the manner described in Section 1.5.1. If within ten days of a party's objection notice the parties have not agreed how to proceed the matter shall be referred to the AAA for resolution.

1.5.3 Arbitration Procedures.

The AAA shall compile and make available to the arbitrator and the parties standard procedures for the arbitration of disputes, which procedures (i) shall conform to the requirements specified herein~~,~~ and (ii) may be modified or adopted for use in a particular proceeding as the arbitrator deems appropriate, in accordance with Section 1.5.4 The procedures shall be based on the latest edition of the American Arbitration Association Commercial Arbitration Rules, to the extent such rules are not inconsistent with this Schedule K. Except as provided herein, all parties shall be bound by such procedures.

1.5.4 Modification of Arbitration Procedures.

In determining whether to modify the standard procedures for use in the pending matter, the arbitrator shall consider (i) the complexity of the dispute, (ii) the extent to which facts are disputed, (iii) the extent to which the credibility of witnesses is relevant to a resolution, (iv) the amount in controversy, and (v) any representations made by the parties. Alternatively, the parties may, by mutual agreement, modify the standard procedures. In the event of a disagreement between the arbitrator and the agreement of the parties regarding arbitration procedures to be utilized, the parties' agreement shall prevail.

1.5.5 Remedies.

1.5.5.1 Arbitrator's Discretion. The arbitrator shall have the discretion to grant the relief sought by a party~~,~~ or determine such other remedy as is appropriate, unless the parties agree to conduct the arbitration "baseball" style. Unless otherwise expressly limited herein, the arbitrator shall have the authority to award any remedy or relief available from FERC, or any court of competent jurisdiction. Where this Agreement leaves any matter to be agreed between the parties at some future time and provides that in default of agreement the matter shall be referred to the ADR, the arbitrator shall have authority to decide upon the terms of the agreement which, in the arbitrator’s opinion, it is reasonable that the parties should reach, having regard to the other terms this Agreement concerned and the arbitrator’s opinion as to what is fair and reasonable in all the circumstances.

1.5.5.2 "Baseball" Arbitration. If the parties agree to conduct the arbitration "baseball" style, the parties shall submit to the arbitrator and exchange with each other their last best offers in the form of the award they consider the arbitrator should make, not less than seven days in advance of the date fixed for the hearing, or such later date as the arbitrator may decide. If a party fails to submit its last best offer in accordance with this Section, that party shall be deemed to have accepted the offer proposed by the other party. The arbitrator shall be limited to awarding only one of the proposed offers, and may not determine an alternative or compromise remedy.

1.5.6 Summary Disposition.

The procedures for arbitration of a dispute shall provide a means for summary disposition of a demand for arbitration, or a response to a demand for arbitration, that in the reasoned opinion of the arbitrator does not have a good faith basis in either law or fact. If the arbitrator determines that a demand for arbitration or response to a demand for arbitration does not have a good faith basis in either law or fact, the arbitrator shall have discretion to award the costs of the time, expenses, and other charges of the arbitrator to the prevailing party. A determination made under this Section is subject to appeal pursuant to Section 1.6.

1.5.7 Discovery Procedures.

The procedures for the arbitration of a dispute shall include adequate provision for the discovery of relevant facts, including the taking of testimony under oath, production of documents and other things, the presentation of evidence, the taking of samples, conducting of tests, and inspection of land and tangible items. The nature and extent of such discovery shall be determined as provided herein and shall take into account (i) the complexity of the dispute, (ii) the extent to which facts are disputed, (iii) the extent to which the credibility of witnesses is relevant to a resolution, and (iv) the amount in controversy. The forms and methods for taking such discovery shall be as described in the Federal Rules of Civil Procedure, except as modified pursuant to Section 1.5.4.

1.5.8 Evidentiary Hearing.

The arbitration procedures shall provide for an evidentiary hearing, with provision for the cross-examination of witnesses, unless all parties consent to the resolution of the matter on the basis of a written record. The forms and methods for taking evidence shall be determined by the arbitrator(s) and modified pursuant to Section 1.5.4. The arbitrator may require such written or other submissions from the parties as he or she may deem appropriate, including submission of direct and rebuttal testimony of witnesses in written form. The arbitrator may exclude any evidence that is irrelevant, immaterial, unduly repetitious or prejudicial, or privileged. The arbitrator shall compile a complete evidentiary record of the arbitration that shall be available to the parties on its completion upon request.

1.5.9 Confidentiality.

Subject to the other provisions of this Agreement, any party may claim that information contained in a document otherwise subject to discovery is "Confidential" if such information would be so characterized under the Federal Rules of Evidence or the provisions of the Agreement. The party making such claim shall provide to the arbitrator in writing the basis for its assertion. If the claim of confidentiality is confirmed by the arbitrator, he or she shall establish requirements for the protection of such documents or other information designated as "Confidential" as may be reasonable and necessary to protect the confidentiality and commercial value of such information. Any party disclosing information in violation of these provisions or requirements established by the arbitrator, unless such disclosure is required by federal or state law or by a court order, shall thereby waive any right to introduce or otherwise use such information in any judicial, regulatory, or other legal or dispute resolution proceeding, including the proceeding in which the information was obtained.

1.5.10 Timetable.

Promptly after the appointment of the arbitrator, the arbitrator shall set a date for the issuance of the arbitration decision, which shall be no later than six months (or such earlier date as the parties and the arbitrator may agree) from the date of the appointment of the arbitrator, with other dates, including the dates for an evidentiary hearing or other final submissions of evidence, set in light of this date. The date for the evidentiary hearing or other final submission of evidence shall not be changed, absent extraordinary circumstances. The arbitrator shall have the power to impose sanctions, including dismissal of the proceeding, for dilatory tactics or undue delay in completing the arbitration proceedings.

1.5.11 Decision.

1.5.11.1 Except as provided below with respect to "baseball" style arbitration, the arbitrator shall issue a written decision granting the relief requested by one of the parties, or such other remedy as is appropriate, if any, and shall include findings of fact and law. The arbitration decision shall be based on (i) the evidence in the record, (ii) the terms of this Agreement and to the extent relevant, the ISO Tariff and Protocols, (iii) applicable United States federal law, including the Federal Power Act and any applicable FERC regulations and decisions, and international treaties or agreements as applicable, and (iv) applicable state law. Additionally, the arbitrator may consider relevant decisions in previous arbitration proceedings involving this Agreement. To the extent it may do so without violating confidentiality requirements, a summary of the disputed matter and the arbitrator's decision may be published in an ISO newsletter on ISO's Home Page.

1.5.11.2 In arbitration conducted "baseball" style, the arbitrator shall issue a written decision adopting one of the awards proposed by the parties, and shall include findings of fact and law. The arbitration decision shall be based on (i) the evidence in the record, (ii) the terms of this Agreement and to the extent relevant, the ISO Tariff and Protocols, (iii) applicable United States federal law, including the Federal Power Act and any applicable FERC regulations and decisions, and international treaties or agreements as applicable, and (iv) applicable state law. If the arbitrator concludes that no proposed award is consistent with the factors enumerated in (i) through (iv) above, or addresses all of the issues in dispute, the arbitrator shall specify how each proposed award is deficient and direct that the parties submit new proposed awards that cure the identified deficiencies. To the extent it may do so without violating confidentiality requirements, a summary of the disputed matter and the arbitrator's decision may be published in an ISO newsletter on

ISO's Home Page.

1.5.11.3 Where a panel of arbitrators is appointed pursuant to Section 1.5.1.2, a majority of the arbitrators must agree on the decision. An award shall not be deemed to be precedent except in so far as a future dispute between the parties involves the same issue.

1.5.12 Compliance.

Unless the arbitrator's decision is appealed under Section 1.6, the disputing parties shall, upon receipt of the decision, immediately take whatever action is required to comply with the award to the extent the award does not require regulatory action. An award that is not appealed shall be deemed to have the same force and effect as an order entered by FERC or any court of competent jurisdiction.

1.5.13 Enforcement.

Following the expiration of the time for appeal of an award pursuant to Section 1.6.3, any party may apply to FERC or any court of competent jurisdiction for entry and enforcement of judgment based on the award.

1.5.14 Costs.

The costs of the time, expenses, and other charges of the arbitrator shall be borne by the parties to the dispute, with each side on an arbitrated issue bearing its pro-rata share of such costs, and each party to an arbitration proceeding bearing its own costs and fees. If the arbitrator determines that a demand for arbitration or response to a demand for arbitration was made in bad faith, the arbitrator shall have discretion to award the costs of the time, expenses, and other charges of the arbitrator to the prevailing party.

1.6 Appeal of Award.

1.6.1 Basis for Appeal.

A party may apply to the FERC or any court of competent jurisdiction to hear an appeal of an arbitration decision only upon the grounds that the decision is contrary to or beyond the scope of this Agreement and to the extent relevant, the ISO Tariff and Protocols, United States federal law, including, without limitation, the Federal Power Act, and any applicable FERC regulations and decisions, or state law. Appeals shall, unless otherwise ordered by FERC or the court of competent jurisdiction, conform to the procedural limitations set forth in this Section 1.6.

1.6.2 Appellate Record.

The parties intend that FERC or a court of competent jurisdiction should afford substantial deference to the factual findings of the arbitrator. No party shall seek to expand the record before FERC or a court of competent jurisdiction beyond that assembled by the arbitrator, except (i) by making reference to legal authority which did not exist at the time of the arbitrator's decision, or (ii) if such party contends the decision was based upon or affected by fraud, collusion, corruption, misconduct or misrepresentation.

1.6.3 Procedures for Appeals.

1.6.3.1 If a party to an arbitration desires to appeal a decision, it shall provide a notice of appeal to all parties and the arbitrator(s) within 14 days following the date of the decision.

Within ten days of the filing of the notice of appeal, the appealing party must file an appropriate application, petition or motion with FERC for review under the Federal Power Act or with a court of competent jurisdiction. Such filing shall state that the subject matter has been the subject of an arbitration pursuant to this Agreement and, to the extent relevant, the ISO Tariff and protocols.

1.6.3.2 Within 30 days of filing the notice of appeal (or such period as FERC or the court of competent jurisdiction may specify) the appellant shall file the complete evidentiary record of the arbitration and a copy of the decision with FERC or with the court. The appellant shall serve on all parties to the arbitration copies of a description of all materials included in the submitted evidentiary record.

1.6.4 Award Implementation.

Implementation of the decision shall be deemed stayed pending an appeal unless and until, at the request of a party, FERC or the court of competent jurisdiction with which an appeal has been filed, issues an order dissolving, shortening, or extending such stay.

A summary of each appeal shall be published in an ISO newsletter on the ISO Home Page.

1.6.5 Judicial Review of FERC Orders.

FERC orders resulting from appeals shall be subject to judicial review pursuant to the Federal Power Act.

SCHEDULE L-1

REQUEST FOR APPROVAL OF CAPITAL ITEMS OR REPAIRS

This form should be used to request ISO approval of Planned Capital Items, Unplanned Repairs or Unplanned Capital Items pursuant to Sections 7.4, 7.5 or 7.6 of the Agreement.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR
RELIABILITY MUST-RUN UNIT
CAPITAL ITEM AND REPAIR PROJECT REQUEST

Date: **CA ISO Project Number:**

Facility: **Unit:**

Owner: **Location:**

This request covers:

( ) Capital Items for the next Contract Year (preliminary)
( ) Capital Items for the next Contract Year (final)
( ) Unplanned Repairs
( ) Unplanned Capital Items

If this request covers Capital Items for the next Contract Year, provide:

Small Project Estimate (reliability)

Small Project Estimate (other)

Identify separately each Capital Item included in a small project estimate projected to cost more than $50,000.

If this request covers Unplanned Repairs, or Capital Items projected to cost more than $500,000, provide the information in the remainder of this form for each project.

Project Description: (describe the project and its major scope items – materials, new systems, modifications to existing systems, etc.)

If the project is required because of loss or damage to a Unit, describe the cause and nature of the loss or damage and all repairs performed or required for all Units during the year:

Project Budget:

Year	Labor	Material	Contract	Int Svc	Other	Material	Over head AEGE	Total Cost	AD VAL TAX	Total Expenditures	Total Financial Costs

Describe any work or repairs performed relating to this project in the last five years:

As applicable, state the proposed depreciation life, Annual Capital Item Cost, Surcharge Payment Factor or Repair Payment Factor (percentage owed by ISO) of the Capital Item or Repair:

Describe why this project is required (justification):

Is this project required to comply with any laws, regulations or permits? If so, please list them and explain requirement.

Provide a cost/benefit analysis summary for this project:

Include all assumptions including changes to unit performance [efficiency, aux. power loads, etc.], impact on Maximum Net Dependable Capacity, grid interconnection/metering impacts, etc.

Describe the impacts on the Unit's ability to perform its obligations under this Agreement if this project is not approved:

Describe alternatives to this project that were evaluated and the projected costs of those alternatives:

Describe alternatives along with their major scope items. Also, compare the projected cost of these alternatives with the selected alternative, and compare the unit performance impacts (efficiency, auxiliary power demands, Maximum Net Dependable Capacity effects, etc.) of these alternatives against the chosen alternative.

List any proceeds received or expected to be received by Owner from insurers or other third parties pursuant to applicable insurance, warranties and other contracts in connection with the project.

Provide the schedule for implementing this project:

Event	Begin	Complete

Describe any outages required to implement this project:

Other comments:

SCHEDULE L-2

CAPITAL ITEM AND REPAIR PROGRESS REPORT

CALIFORNIA INDEPENDENT SYSTEM OPERATOR
RELIABILITY MUST-RUN UNIT
CAPITAL ITEM AND REPAIR PROGRESS REPORT

Date: **CA ISO Project Number:**

Facility: **Unit:**

Owner: **Location:**

Capital Item or Repair:

Original In-Service Date: **Current In-Service Date:**

If Current In-Service Date has changed, describe the reason why:

Describe any additional costs or savings resulting from the change in the Current In-Service Date:

Describe what portion of any additional costs Owner is requesting ISO to pay, and why Owner believes that ISO should be obligated to pay those additional costs:

SCHEDULE M

Mandatory Market Bid for Condition 2 Units
When Dispatched by the ISO

Energy Bid

The bid the Owner of a Condition 2 Fossil Fuel Unit must submit into Energy markets when dispatched by the ISO is given in Equation M-1a (for Units with input/output data in polynomial form) or Equation M-1b (for Units with input/output data in exponential form):

Equation M-1a

$$\text{Energy Bid (\$/MWh)} = \frac{(AX^3 + BX^2 + CX + D)}{X} \times P \times E$$

+ [Variable O&M Rate + Emissions Rates + Scheduling Coordinator Charge + ACA Charge]

Equation M-1b

$$\text{Energy Bid (\$/MWh)} = \frac{A\ ?\ (B + CX + De^{FX})}{X} \times P \times E$$

+ [Variable O&M Rate + Emissions Rate + Scheduling Coordinator Charge + ACA Charge]

Where:

- for Equation M-1a, A, B, C, D and E are the coefficients given in Table C1-7a;
- for Equation M-1b, A, B, C, D, E and F are the coefficients given in Table C1-7b;
- X is the Unit Availability Limit, MW;
- P is the Hourly Fuel Price as calculated by Equation C1-8 in Schedule C using the Commodity Prices most recently published before the day the bid is submitted.
- Scheduling Coordinator Charge (\$/MWh): The PX Administration Charge under the PX Tariff.
- ACA Charge (\$/MWh): The applicable annual charge for short-term sales under 18 CFR Section 382.201 of the FERC Regulations.
- Variable O&M Rate (\$/MWh): as shown on Table C1-18

For Units in the SCAQMD only

Emissions Rate (\$/MWh) = Emissions Cost / Unit Availability Limit

Emissions Cost = (a) RECLAIM Cost + (b) NOx Emissions Cost + (c) Organic Gases Cost + (d) Sulfur Oxides Cost + (e) Particulate Matter Cost + (f) Carbon Monoxide Cost

(a) RECLAIM Cost = $((AX^2+BX+C)$ * RECLAIM NOx Trading Credit Rate

(b) NOx Emissions Cost = $\frac{(AX^2+BX+C)}{2000}$ * NOx Emissions Fee

Where:

A, B and C are the coefficients from Table C1-13;

X = Unit Availability Limit;

(c) Organic Gases Cost =

4.76×10^{-7} * (Gas Fuel) * Associated Emission Factor for Organic Gases * Associated Emissions Fee for Organic Gases

(d) Sulfur Oxides Cost =

4.76×10^{-7} * (Gas Fuel) * Associated Emission Factor for Sulfur Oxides * Associated Emissions Fee for Sulfur Oxides

(e) Particulate Matter Oxides Cost =

4.76×10^{-7} * (Gas Fuel) * Associated Emission Factor for Particulate Matter * Associated Emission Fee for Particulate Matter

(f) Carbon Monoxide Cost =

4.76×10^{-7} * (Gas Fuel) * Associated Emission Factor for Carbon Monoxide * Associated Emission Fee for Carbon Monoxide

Where:

Gas Fuel = $AX^3 + BX^2 + CX + D$ or $A ? (B + CX + De^{FX})$, depending on the form of heat input the Owner is using

- A, B, C, D are the coefficients from C1-7a or C1-7b;
- F is the coefficient from C1-7b;
- X = Unit Availability Limit;
- Factors and Associated Emission fees are determined in Schedule C, Section D.3.

The bid the Owner of a geothermal Condition 2 Unit must submit into Energy markets when dispatched by the ISO is given in Equation M-2.

Equation M-2

Energy Bid ($/MWh) = Fuel Cost + [Variable O&M Rate + Scheduling Coordinator Charge + ACA Charge]

Where:

- The Fuel Cost is the Steam Price identified in Equation C2-1 in Schedule C. However, for purposes of this mandatory market bid, the value for the Steam Price will be zero for Geysers Main Units until the cumulative Hourly Metered Total Net Generation during the Contract Year from all Units exceeds the Minimum Annual Generation given in Equation C2-2.

- Variable O&M Cost ($/MWh): the cost shall be as shown on Table C2-1.

- Scheduling Coordinator Charge: The PX Administration Charge under the PX Tariff.

- ACA Charge ($/MWh): The applicable annual charge for short-term sales under 18 C.F.R. Section 382.201 of the FERC Regulations.

Ancillary Services Bid

The bid the Owner of a Condition 2 Unit must submit into Ancillary Service markets when dispatched by ISO is as follows:

$$\text{Ancillary Services Bid (\$/MW per hr)} = \left[\frac{\text{Annual Fixed Revenue Requirement (\$)}}{\left(\begin{array}{c}\text{30 minutes x Unit's}\\ \text{Highest Ramp Rate}\\ \text{from Schedule A,}\\ \text{MW/min}\end{array}\right) \times \left(\begin{array}{c}\text{Target}\\ \text{Available}\\ \text{Hours}\end{array}\right)} - \frac{\text{Annual Fixed Revenue Requirement (\$)}}{\left(\begin{array}{c}\text{Maximum}\\ \text{Net}\\ \text{Dependable}\\ \text{Capacity}\end{array}\right) \times \left(\begin{array}{c}\text{Target}\\ \text{Available}\\ \text{Hours}\end{array}\right)} \right]$$

2

Annual Fixed Revenue Requirement is shown in Schedule B.
Target Available Hours is shown in Schedule B.
The product of 30 minutes times the Unit's highest Ramp Rate in Schedule A shall not exceed the Unit's Maximum Net Dependable Capacity.

Schedule N-1

NON-DISCLOSURE and CONFIDENTIALITY AGREEMENT
for RESPONSIBLE UTILITY

[Name of Responsible Utility] (the “Responsible Utility”) acknowledges that **[Name of Owner]** (“Owner”) and the California Independent System Operator Corporation (“ISO”) (jointly, the “Providing Parties” and severally, the “Providing Party”) have agreed to provide certain information to the Responsible Utility pursuant to certain provisions of the Must-Run Service Agreement (“MRSA”) between Owner and ISO and as required for settlement and billing of charges under Article 9 of such Agreement. In order to permit the Responsible Utility to receive such Confidential Information from Owner or ISO pursuant to the above-referenced provisions of the MRSA, the Responsible Utility and the Providing Parties hereby agree as follows:

(1) For purposes of this Non-Disclosure and Confidentiality Agreement, the term “Confidential Information” shall have the same meaning it has in Section 12.5 of the MRSA, a copy of which is appended;

(2) The Providing Parties shall provide such Confidential Information pursuant to the terms of this Non-Disclosure and Confidentiality Agreement;

(3) The Responsible Utility shall keep such Confidential Information confidential, shall use it only for the purposes related to the MRSA, and shall limit the disclosure of any such Confidential Information to only those personnel within its organization with responsibility for using such information in connection with the MRSA. Such personnel may not include any person whose duties include (i) the marketing or sale of electric power or natural gas or gas transportation capacity at wholesale or retail, (ii) the purchase of electric power or natural gas or gas transportation capacity at wholesale or retail, (iii) the direct supervision of any employee with such responsibilities, or (iv) the provision of electricity or natural gas marketing consulting services to any employee with such responsibilities;

(4) The Responsible Utility shall assure that personnel within its organization read and comply with the provisions of this Non-Disclosure and Confidentiality Agreement;

(5) The Responsible Utility shall use all reasonable efforts to maintain the confidentiality of the Confidential Information in any litigation, and shall promptly notify the providing Party of any attempt by a third party to obtain the Confidential Information through legal process or otherwise;

(6) The Responsible Utility may use Confidential Information in litigation or regulatory proceedings related to the Must-Run Service Agreement between Owner and ISO but only after notice to the Providing Party and affording the Providing Party an opportunity to obtain a protective order or other relief to prevent or limit disclosure of the Confidential Information.

The Responsible Utility agrees to be bound by the terms of Section 12.5 of the MRSA in the same manner and to the same extent as the Providing Parties. The person signing on behalf of the Responsible Utility represents that he/she is authorized to bind the Responsible Utility to the terms of this Non-Disclosure and Confidentiality Agreement.

The undersigned signatory represents that he/she is authorized to bind the Responsible Utility, to the terms of this Non-Disclosure and Confidentiality Agreement.

Signature:

Name:
Title:
Responsible Utility:
Address:

Telephone:

Signature:
Name:
Title:
Owner:
Address:

Telephone:

Signature:
Name:
Title:
California Independent System Operator Corporation
Address:

Telephone:

Schedule N-2

NON-DISCLOSURE and CONFIDENTIALITY AGREEMENT
for PERSONS OTHER THAN THE RESPONSIBLE UTILITY

[Name of] (the "Receiving Party") acknowledges (a) that **[Name of Owner]** ("Owner") has agreed to provide Confidential Information to the California Agency pursuant to certain provisions of the Must-Run Service Agreement ("MRSA") between Owner and the California Independent System Operator Corporation ("ISO"), and (b) that Owner and ISO (jointly, the "Providing Parties" and severally, the "Providing Party") may provide Confidential Information on a need-to-know basis to Owner's Scheduling Coordinator, financial institutions, agents and potential purchasers of interests in a Unit; and, as required for settlement and billing, to Scheduling Coordinators responsible for paying for services provided under the MRSA between Owner and ISO. In order to permit the Receiving Party to receive such Confidential Information from Owner or ISO, the Receiving Party and the Providing Parties hereby agree as follows:

(1) For purposes of this Non-Disclosure and Confidentiality Agreement, the term "Confidential Information" shall have the same meaning it has in Section 12.5 of the MRSA between Owner and ISO, a copy of which is appended;

(2) The Providing Parties shall provide such Confidential Information pursuant to the terms of this Non-Disclosure and Confidentiality Agreement;

(3) The Receiving Party shall keep such Confidential Information confidential, shall use it only for the purposes related to the MRSA, and shall limit the disclosure of any such Confidential Information to only those personnel within its organization with responsibility for using such information in connection with the MRSA upon their execution of this Non-Disclosure and Confidentiality Agreement. Such personnel may not include any person whose duties include (i) the marketing or sale of electric power or natural gas or gas transportation capacity at wholesale or retail, (ii) the purchase of electric power or natural gas or gas transportation capacity at wholesale or retail, (iii) the direct supervision of any employee with such responsibilities, or (iv) the provision of electricity or natural gas marketing consulting services to any employee with such responsibilities;

(4) The Receiving Party shall assure that personnel within its organization authorized to receive Confidential Information read and comply with the provisions of this Non-Disclosure and Confidentiality Agreement;

(5) The Receiving Party shall use all reasonable efforts to maintain the confidentiality of the Confidential Information in any litigation, and shall promptly notify the providing Party of any attempt by a third party to obtain the Confidential Information through legal process or otherwise;

The Receiving Party agrees to be bound by the terms of Section 12.5 of the MRSA in the same manner and to the same extent as the Providing Parties. The person signing on behalf of the Receiving Party represents that he/she is authorized to bind the Receiving Party to the terms of this Non-Disclosure and Confidentiality Agreement.

Signature:
Name:
Company:
Title:
Receiving Party:

Address:

Telephone:

Signature:
Name:
Owner:
Title:
Address:

Telephone:

Signature:
Name:
California Independent System Operator Corporation
Title:
Address:

Telephone:

SCHEDULE O

RMR Owner's Invoice Process

The following principles and practices shall govern the submission of invoices to the ISO for Energy and Ancillary Services provided under this Agreement ("RMR services"):

1 Invoices submitted by Owner to the ISO for RMR services shall be clear, understandable and complete.

2. The ISO, all RMR Owners and Responsible Utilities shall agree on the RMR invoice template, which agreement shall not be unreasonably withheld, prior to its implementation. The ISO shall publish the current version of the RMR invoice template by including it on the ISO Home Page. The ISO will specifically tell each Owner and Responsible Utility where on the ISO Home Page this RMR invoice template can be found. Each Owner shall use the then current RMR invoice template for invoicing RMR services for each Facility. The RMR invoice template may change from time to time. The ISO shall notify the California Agency, all RMR Owners and Responsible Utilities when a new agreed upon RMR invoice template has been placed on the ISO Home Page.

3. Subject to the provisions of paragraph 4 below, a Completed RMR invoice based on the version of the RMR invoice template posted on the ISO's Home Page seven days prior to submission of the invoice shall be deemed to satisfy the requirements of this Agreement. As used herein, the term "Completed RMR invoice" means that: (a) all of the raw data required to calculate debits and credits have been included; (b) all calculations have been performed in accordance with the formulae in the current RMR invoice template, or in the event that Owner believes a conflict exists between one or more formula(s) in the RMR Owner's invoice and the corresponding formula in the RMR invoice template, such conflict has been identified and substitute equations have been documented and used at the appropriate location(s) in the invoice; (c) linkages between invoice levels are identified; (d) all billing and service assumptions, data inputs and formulae reasonably necessary to understand the derivation of each charge on the invoice has been included; and (e) the invoice has been provided to the ISO and the Responsible Utility.

4. The Estimated RMR invoice or the Adjusted RMR invoice timeline set forth in the ISO's RMR Payments Calendar (for the appropriate invoice) shall not commence, payments shall not be made and interest shall not begin to accrue until a Completed RMR invoice has been submitted to the ISO and Responsible Utility.

5. In the event of any conflict between the RMR invoice template and this Agreement, this Agreement shall govern. The Owner or Responsible Utility detecting the conflict shall promptly give notice to the ISO. The ISO shall notify all RMR Owners and all Responsible Utilities as soon as practicable after a conflict has been identified.

6. If Owner identifies a conflict, Owner shall identify the conflict in its letter transmitting its completed Estimated or Adjusted RMR invoice to the ISO and include therein Owner's revised formula, which will be effective until agreement has been reached among the ISO, Owner, the other RMR Owners and the Responsible Utilities on the correct formula, or a decision has been rendered through ADR from which no further appeal is possible.

7. An RMR Invoice Task Force has been formed with representatives from each of the RMR Owners, the Responsible Utilities and the ISO. When a conflict has been identified, the ISO, Owner, the other RMR Owners and the Responsible Utility will participate in meetings of the RMR Invoice Task Force to reach agreement on a revised RMR invoice template. The RMR Invoice Task Force shall meet at least monthly until all conflicts are resolved. Once all conflicts have been resolved, the

RMR Invoice Task Force will meet approximately every six months to address invoicing and payment issues.

8. The RMR Invoice Task Force also shall be responsible for simplifying the RMR invoices so that they are easier to process and less burdensome to prepare.

9. To the extent that the Owner, the ISO and the Responsible Utility have agreed, certain columns in the Owner's RMR invoice template shall be standard for the Facility and shall not change. The Owner shall not be required to complete such columns each month on its invoice for it to be considered a Completed RMR invoice, unless the underlying information requirements change.

10. Owner shall supply monthly RMR Level 0-3 invoice information in accordance with the RMR invoice template for each Responsible Utility service territory as follows:

    1. Level 0: the summary invoice for Owner's total amount invoiced to the ISO for all of Owner's Facilities;

    2. Level 1: the summary invoice for all RMR Units at a Facility;

    3. Level 2: the detailed calculated information for individual RMR Units at the Facility; and

    4. Level 3: the detailed hourly data for individual RMR Units at each Facility.

    Each invoice shall contain such other information as is necessary to perform the calculations, including indicated netted meter reads, ISO Dispatch Notice information (both day-ahead, real time, and adjustments), Owner's Availability Notice information and final market schedule information. No quantities shall be left blank. Each assumption made by the Owner to perform a calculation shall be listed and explained either in the appropriate Level 0-3 template under Notes or in a transmittal letter accompanying the invoice.

    The methods described shall be used to calculate quantities such as Hourly Fuel Price, Hourly Emissions Cost and Start-up calculations used as input data in the RMR invoice template.

    Owner shall indicate any data appearing on the invoice which it considers confidential. Responsible Utility may use the data in accordance with Section 12.5 and Schedule N of this Agreement.

SCHEDULE P

Reserved Energy for Air Emissions Limitations

This Schedule P applies only to Units located within the San Diego Air Quality Control Basin (“Basin”).

1. For purposes of this Schedule P, the term Emission Limitation means present or future limitations on the discharge of air pollutants or contaminants into the atmosphere specified by any federal, state, regional or local law (“Clean Air Law”), by any regulation, air quality implementation plan, or permit condition promulgated or imposed by any agency authorized under any such Clean Air Law or by the judgment of any court of competent jurisdiction.

2. (a) Except as set out in Sections 2 (b) and (c), if a Facility is located in the Basin and is subject to an Emission Limitation that would limit the MWh that can be produced from the Facility during the Contract Year or part thereof (such Contract Year or part being referred to as the “Limitation Period”), Owner shall, so long as some or all of the Units at the Facility are operating under Condition 1, reserve for the Facility for each Month of the Limitation Period for dispatch under this Agreement, a quantity of MWh equal to the average monthly Requested MWh for the Facility for that Month in the 36 Months preceding the next Contract Year (the “Monthly Reserved MWh”).

   (b) If there are less than 36 Months of Requested MWh preceding the next Contract Year, the Monthly Reserved MWh for the Limitation Period shall be determined by agreement between ISO and Owner. If Owner and ISO are unable to reach agreement by October 31 preceding the next Contract Year, Owner or ISO may refer the matter to ADR under a schedule (specified by the arbitrator if the participants cannot agree) requiring a decision within 30 days following appointment of the arbitrator.

   (c) (i) If the Monthly Reserved MWh has been determined in accordance with Section 2(a) and this Agreement terminates as to a Unit at the Facility, the Monthly Reserved MWh shall be adjusted downward to the average of the Requested MWh for the Units that remain subject to this Agreement for the same 36 Month period previously used to calculate the Monthly Reserved MWh.

   (ii) If the Monthly Reserved MWh has been determined in accordance with Section 2 (b) and the Agreement terminates as to a Unit at the Facility, the adjustment shall be determined by agreement of Owner and ISO. If the Parties are unable to reach agreement at least 45 days before the Agreement terminates as to the Unit, Owner or ISO may refer the matter to ADR under a schedule (specified by the arbitrator if the participants cannot agree) requiring a decision within 30 days following appointment of the arbitrator

3. The Monthly Reserved MWh are set forth on Schedule A. No less than 15 days before the beginning of each Contract Year, Owner shall make a Section 205 filing limited to changing the terms of Schedule A to revise the Monthly Reserved MWh determined in accordance with Section 2. The revised Monthly Reserved MWh shall be effective from the first day of the Contract Year.

4. If the sum of the Billable MWh and Hybrid MWh during a Month is less than the Monthly Reserved MWH, ISO may:

   (a) carry forward into the following Months of the Limitation Period all unused Monthly Reserved MWh, provided the cumulative unused MWh that are carried forward into the following Months may not exceed 20% of the aggregate Monthly Reserved MWh for the remainder of the Limitation Period including the Monthly Reserved MWh for the Months into which unused Monthly Reserved MWh are to be carried forward, or

(b) carry forward less than all unused Monthly Reserved MWh and release to Owner the Monthly Unused Reserved MWh not carried forward.

ISO shall notify Owner of the amount of unused Monthly Reserved MWh to be carried forward within 3 Business Days after the beginning of the next Month.

5. ISO may elect to reduce the aggregate Monthly Reserved MWh for the remainder of the Limitation Period by notifying Owner not less than 5 days prior to the beginning of the Month in which the reduction is to be effective. Notwithstanding the foregoing, if ISO or Owner forecasts that usage will approach the Emission Limitation in the last Month of the Limitation Period, ISO and Owner shall closely coordinate to release any unused Monthly Reserved MWh as soon as possible.

6. If there are unused Monthly Reserved MWh for the Facility remaining at the end of the Limitation Period, ISO shall pay the Unused Emission Reserve Payment. The Unused Emission Reserve Payment shall be the product of (a) the Unused Monthly Reserved MWh Payment Rate and (b) the lesser of (i) the unused Monthly Reserved MWh carried forward by the ISO into the last Month of the Limitation Period and (ii) the unused Monthly Reserved MWh remaining at the end of the Limitation Period. The Unused Monthly Reserved MWh Payment Rate shall be $10 per MWh. The Unused Emission Reserve Payment shall be included in the invoice for the last Billing Month of the Limitation Period.

7. If the ISO determines that the Monthly Reserved MWh have become insufficient due to a Force Majeure Event at the Facility or at Reliability Must-Run Units at another facility or because of an outage on the ISO Controlled Grid or the Distribution Grid due to a Force Majeure Event, ISO may request Owner to undertake, and if so requested, Owner shall undertake all such necessary and commercially reasonable measures approved in advance by ISO and the Responsible Utility to (a) obtain, where possible, a modification or variance from applicable Emission Limitations, or (b) procure necessary emission reduction credits or allowances sufficient to offset emissions in excess of Emission Limitations to enable Owner to provide additional MWh dispatched by the ISO to meet reliability requirements arising by reason of such Force Majeure Event. ISO shall reimburse Owner for all reasonable costs of procuring such emission reduction credits or allowances.

8. If the ISO wishes to dispatch a Unit at a Facility that is within 5% of exceeding its Monthly Reserved MWh for the Limitation Period, the ISO shall first dispatch Units at other Facilities that are not within 5% of the Monthly Reserved MWh during the Limitation Period if the other Unit(s), in the ISO's sole judgment, provide equivalent reliability benefits.

9. If any Emission Limitation affecting the Facility materially changes, ISO and Owner promptly shall renegotiate this Schedule P to reflect such change. If ISO and Owner are unable to agree on revisions to this Schedule P, the Owner may file a revised Schedule P with FERC under Section 205 of the Federal Power Act for the limited purpose of taking such changes in the Emissions Limitation into account. Such filing may be with or without the concurrence of the ISO, but ISO reserves its right to protest any such filing.