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			

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

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

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

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

Equation B-3

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

Where:

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

Equation B-4

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

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

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

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

$$\text{Hourly Capital Item Charge} = \text{Hourly Capital Item Rate} * \text{Surcharge Payment Factor}$$

Where:

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

Equation B-9

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

- 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. <u>Annual Fixed Revenue Requirement (AFRR)</u>

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. <u>Limited Section 205 Filing for an Extension of Contract Term</u>

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

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

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

$$\begin{pmatrix}\text{ISO Facility}\\\text{Monthly}\\\text{Billed}\\\text{Fuel Cost}\\\text{(\$)}\end{pmatrix} = \text{Lesser of}\begin{pmatrix}\text{ISO Facility}\\\text{Cumulative}\\\text{Actual}\\\text{Fuel Cost}\\\text{(\$)}\end{pmatrix} \text{ or } \begin{pmatrix}\text{ISO Facility}\\\text{Cumulative}\\\text{Cap}\\\text{Fuel Cost}\\\text{(\$)}\end{pmatrix} - \begin{pmatrix}\text{ISO Facility}\\\text{Cumulative}\\\text{Billed}\\\text{Fuel Cost}\\\text{(\$)}\end{pmatrix}$$

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, including 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, including 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, excluding the current Month. ISO Unit Monthly Billed Fuel Cost for each Unit is calculated in accordance with Equation C1-0.

2. ISO Unit Monthly Actual Fuel Cost

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

Equation C1-2

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

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 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".

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[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%.

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 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:

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[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).

Equation C1-2a

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

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. **<u>ISO Monthly Fuel Price</u>**

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. **<u>Intentionally Omitted</u>** (There is no Equation C1-4.)

5. **<u>ISO Unit Hourly Cap Fuel Cost</u>**

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

Equation C1-5

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

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. **<u>ISO Unit Hourly Cap Heat Input</u>**

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

Equation C1-6

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

Where:

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

7. **<u>Unit Hourly Cap Heat Input (MMBtu)</u>**

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

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

Equation C1-7b

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

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

<u>A</u>	<u>B</u>	<u>C</u>	<u>D</u>	<u>E</u>

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

Trading Day	Index Publication Date* 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 G-EG, 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.

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[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

$$\text{Monthly Fuel Imbalance Charge} = 0.75 * \left(\text{Monthly Sum of Daily Imbalance Charges} - 0.0225 * \text{ISO Facility Monthly Billed Fuel Cost} \right) + 0.25 * \left(\text{Monthly Sum of Daily Imbalance Charges} - 0.10 * \text{ISO Facility Monthly Billed Fuel Cost} \right)$$

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

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

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. **ISO Hourly NOx Emissions Cost**

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

Equation C1-14

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

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

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

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

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

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.