UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company,	**)**	
Complainant,	**)**	
	)	**Docket No. EL00-95-109**
	)	
v.	**)**	
	)	
Sellers of Energy and Ancillary Services	**)**	
Into Markets Operated by the California	**)**	
Independent System Operator and the	**)**	
California Power Exchange,	**)**	
Respondents	**)**	
	)	
Investigation of Practices of the California	**)**	**Docket No. EL00-98-096**
Independent System Operator and the	**)**	
California Power Exchange	**)**	

MOTION FOR LEAVE TO FILE ANSWER AND ANSWER OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO COMMENTS AND PROTESTS ON COMPLIANCE FILING

Pursuant to Rule 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213 (2001), the California Independent System Operator Corporation ("ISO")[1] hereby files its motion for leave to file an answer and answer to comments and protests[2] filed by several parties in this proceeding addressing the ISO's August 17, 2004 compliance filing, in which the ISO provided its proposed methodology for allocating fuel cost allowance amounts during the October 2, 2000 through June 20, 2001 period (the "Refund Period"),

[1] Capitalized terms not otherwise defined herein shall have the meaning set forth in the Master Definitions Supplement, Appendix A to the ISO Tariff.

[2] Comments and/or protests were submitted by the Arizona Electric Power Cooperative ("AEPCO"); California Parties; Competitive Supplier Group ("CSG"); Constellation NewEnergy Inc. ("Constellation"); Dynegy and Williams jointly ("Dynegy/Williams"); Enron Power Marketing ("Enron"); Northern California Power Agency ("NCPA"); Reliant Energy ("Reliant"); and Sempra Energy Trading Corp. ("Sempra").

as required by the Commission's May 12, 2004 Order Addressing Fuel Cost Allowance Issues, 107 FERC ¶ 61,160 (2004) ("Fuel Cost Order").

To the extent that this Answer responds to arguments raised in pleadings styled as "protests," the ISO requests waiver of Rule 213 (18 C.F.R. § 385.213) to permit it to make this Answer. Good cause for this waiver exists here given the nature and complexity of this proceeding and the usefulness of this Answer in ensuring the development of a complete record.

I. ANSWER

A. Time Interval for Allocation of Fuel Costs

As stated in the ISO's compliance filing, the ISO believes that approved fuel costs should be allocated on an hourly basis in order to be as consistent as possible with principles of cost-causation, as well as the level of detail at which calculations of fuel cost allowances must be submitted by generators pursuant to the Fuel Cost Order.

Several suppliers argue that fuel cost allowances should be allocated to buyers of spot market energy on a daily or monthly basis, rather than on an hourly basis, as proposed by the ISO, on the grounds that the Fuel Cost Order does not require them to calculate an submit fuel cost allowances on an hourly basis.[3] For instance, Reliant argues that allocation of fuel cost allowances on an hourly basis as proposed by the ISO is "problematic" because "the CAISO's proposal to allocate on an hourly basis would require generators to submit data

[3] Reliant at 4 ; Sempra at 2; CSG at 4; Constellation at 2.

in a format that the commission had not previously requested."[4] The ISO believes this argument embodies a fundamental misunderstanding of the manner in which the Fuel Cost Order requires fuel cost allowance calculations to be made by generators. In order for suppliers to correctly apply the Commission's methodology for calculating fuel cost allowances, calculations of the quantity of spot energy sales eligible for gas cost allowances must be done on an hourly basis for PX sales and on a 10-minute interval basis for sales made into the ISO Real Time Market.

In its orders addressing the fuel cost allowance in this proceeding, the Commission has made it clear that all fuel cost allowance claims must be associated with specific mitigated sale transactions (*i.e*. had a transaction price greater than the MMCP) into the ISO and PX spot markets. For example, in its order of April 22, 2003 Order Clarifying Fuel Cost Allowance, 103 FERC ¶ 61,078 (2003) ("April 22 Order"), the Commission stated that "no additional fuel cost allowance is appropriate during intervals where sales were not mitigated. The need to provide an additional fuel cost allowance is tied to the mitigation of the single market clearing price. In intervals where the MCP was lower than the MMCP, there is no need to provide an additional fuel cost allowance. Thus, generators' submissions of their daily costs of gas should exclude gas costs associated with non-mitigated intervals." *Id*. at P 22.

The Commission reaffirmed this approach in the Fuel Cost Order, explaining that "the fuel cost allowance is an offset to allow a generator to recover its cost of fuel *for transactions for which it has refund liability*." Fuel Cost

4 Reliant at 4; *see also* Constellation at 2.

Order at P 18 (emphasis added). The Fuel Cost Order further specified that fuel cost allowance claims filed by generators must include "MW-hours by unit sold to the ISO/PX over the applicable interval (to be the same as that used by the ISO)". *Id*. at 22. For PX Day Ahead market sales, the applicable interval used by the ISO is *hourly.* For the ISO real time energy markets, the applicable interval used by the ISO is each *10-minute interval* within each hour. Thus, in order to comply with the Fuel Cost Order, suppliers claiming a fuel cost allowance must provide all calculations for each unit on a transaction-by-transaction basis, on the same hourly and 10-minute interval level upon which settlement and mitigation in the PX and ISO markets actually occurs.[5]

The need to perform and support fuel cost allowance flings with transaction level on hourly and 10-minute level in the PX and ISO spot markets, respectively, is explained and illustrated in further detail in the *Format for Fuel Cost Allowance Submissions* that has been provided to generators by the ISO pursuant to the Commission's September 2, 2004 Order on Auditor Selection and Request for Waiver and Clarification, 108 FERC ¶ 61,219 (2004) ("Auditor Order"). A copy of this document is included as Attachment A to this filing. [6]

Several parties also argue that fuel cost allowances should be allocated to buyers of spot market energy on a daily or monthly basis, on the grounds that this more closely corresponds with how gas costs and markets function. [7] However, the fact that gas purchases and average prices must be determined on

[5] Both AEPCO and the California Parties agree that fuel cost allowances should be calculated on an hourly basis. See AEPCO at 3; California Parties at 2.
[6] This document has also been posted on the ISO's website.
[7] Constellation at 2; CSG at 4-5.

a daily basis does not mean that fuel cost allowances cannot be calculated on an hourly basis. Once quantities of energy sales (and the incremental gas burned to produce this energy) are determined on a hourly or 10-minute basis, the sum of total gas consumption eligible for recovery over the entire day is combined with data on daily gas purchases to calculate the average cost of gas eligible for recovery for that day. However, this average daily gas price must then be applied back to hourly and 10-minute transaction quantities and prices in order to calculate the appropriate fuel cost allowance relating to that day. Thus, at the completion of this stage of the process, the total fuel cost allowance exists for each transaction on an hourly or, in the case of ISO transactions, a 10-minute basis. An illustrative example of this is provided in Exhibit 1 to the ISO's *Format for Fuel Cost Allowance Submissions*.

Although these hourly/10-minute fuel costs can be aggregated to a daily or monthly level, the ISO believes such aggregation ultimately reduces the degree of accuracy with which these costs are allocated to purchases of spot market energy actually associated with these costs. Since data on purchases of all spot market energy are available on an hourly basis, the ISO believes it is most equitable to allocate fuel cost allowances associated with each hour to spot market sales for that same hour. Another reason for calculating and allocating the fuel cost allowance on an hourly basis is noted by AEPCO, who points out that "use of a longer period to calculate and/or allocate fuel allowances would introduce distortions in terms of heat rates and netting of periods when a seller covered and did not cover its fuel costs." [8]

Finally, it should be understood that although one of the major components of overall fuel cost allowance calculations is based on daily calculations (namely, the average price of daily gas purchases assigned to gas consumption for mitigated transactions during that operating day), there is no logical rationale (such as cost-causation or the level of data available) supporting the allocation of gas allowances on a monthly basis, as suggested by several suppliers. The only reason cited by these sellers in support of monthly allocation is that the Fuel Cost Order proposed the submission of a monthly summary of fuel allowance charges. *See* Fuel Cost Order at P 76 (v). However, the Commission in that order did not require monthly aggregation of fuel costs, instead directing the ISO to inform the Commission if the proposed format for submission of fuel cost allowances would not be adequate. *Id*. at P 77. The ISO did so in its compliance filing, indicating that it would not be possible to perform an hourly allocation of fuel costs using data aggregated on a monthly basis. Given that the Fuel Cost Order, along with the Commission's other orders addressing the fuel cost allowance, clearly requires that fuel cost calculations be performed on a transaction-by-transaction basis, and that the hourly allocation of fuel cost allowances is most consistent with the principle of cost-causation, the Commission should approve the ISO's proposal to allocate the fuel cost allowance on an hourly basis to purchasers in the spot market.

[8] AEPCO at 3. As noted further by AEPCO, "the hourly allowance can be summed on a daily, monthly or other basis as may be needed for other purposes." *Id*.

B. Netting of Spot Market Sales and Purchases

Several parties object to the ISO's proposal to net sales and purchases for purposes of allocating fuel cost allowances.[9] These parties argue that netting sales and purchases "skews the allocation" of fuel costs or may lead to inappropriate results. The ISO maintains that netting sales against purchases results in an allocation methodology that accurately reflects the degree to which entities actually relied on spot market energy. First, netting is the most equitable manner for allocating fuel allowance costs among the state's major utilities, given that during a portion of the Refund Period, those utilities were required to sell all of their generation through the California Power Exchange ("PX"), and the fact that their generation was non-gas-fired, and therefore, not eligible for fuel cost recovery.

To illustrate this point, assume that two utilities both had "gross" purchases of 100 MW in the PX one hour, and that the second of these of these utilities also sold 50 MW from a non-gas-fired unit into the PX that hour. Thus, the first utility had net purchases of 100 MW in the PX, while the second utility had net purchases of 50 MW. Without netting, each utility would be allocated the same share of any approved fuel allowance costs, even though the second utility relied on the spot market to serve only 50 MW of demand (100 MW of purchases from the PX minus the 50 MW of energy that it was required to sell through the PX). This inequitable result can be avoided by netting these sales and purchases. By allocating fuel cost allowances based on net purchases, two-

[9] Reliant at 2; Dynegy/Williams at 3-4; Enron at 3.

thirds of the fuel allowance costs would be allocated to the first utility (with net purchases of 100 MW), while the remaining one-third of the fuel costs would be allocated to the second utility (with net purchases of 50 MW).

The ISO also believes that netting is the most equitable and practical approach in the ISO Markets, due to the fact that, under the ISO Tariff, positive and negative uninstructed energy for all loads and supply resources in the portfolio of each Scheduling Coordinator ("SC") are netted together for each 10-minute interval in the ISO billing process, with each SC being charged or credited based on whether the net deviation of the SC's overall portfolio is positive or negative. *See* ISO Tariff, SABP Section 4.1.2(b).

The ISO's proposal for allocating fuel allowance costs based on net purchases was premised on the understanding that fuel cost allowances for net suppliers would also be *calculated* by using generators' net spot market sales each hour, after accounting for any purchases of energy in the PX and ISO spot markets during the same time interval. The example provided by Dynegy and Williams illustrates the equity of netting under this assumption, and highlights the need to clarify how gas cost allowances are to be calculated when determining the approach used to allocate these costs.

In the Dynegy/Williams example, a generator has sold 10 MWh of instructed energy from one unit (Unit A), while having 12 MWh of negative uninstructed energy purchases from another unit (Unit B). Dynegy/Williams at 4. The ISO's proposed allocation methodology is based on the ISO's understanding that the generator in this example would not be eligible for a fuel cost recovery for this hour under the Fuel Cost Order because it was a net buyer of 2 MWh rather than a net seller of spot market energy that hour. As applied to the example provided by Dynergy and Williams, the ISO's methodology appropriately allocates a share of any fuel cost allowances associated with net sales by other generators that hour to the generator because this generator relied upon the spot market that hour as net buyer rather than net seller.

Enron also provides a hypothetical example which it maintains illustrates the arbitrary and inequitable outcome that would result from allocating fuel cost allowances based on net purchases, as proposed by the ISO.[10] In Enron's example, 98 out of 100 market participants each have gross sales of 1,000 MWh and gross purchases of 1,000 MWh, and therefore have net purchases of 0. Meanwhile, Enron assumes that only one participant is a net seller (with sales of 1,000 MWh and no purchases), while the remaining participant is the only net buyer (with purchases of 1,000 MWh and no sales). Enron further assumes that these generators are eligible to recover fuel costs for their 100 of gross sales, but are then not allocated any share of the overall fuel cost allowances paid to all generators for the 1,000 MWh of spot market energy purchases they made. Obviously, this creates an inequitable outcome, in which a single net buyer ends up paying all of the gross fuel cost allowances claimed by the 98 generators, despite that fact that these 98 generators actually provided zero net sales of spot market energy.

However, the ISO's methodology for fuel cost allocation is based on the understanding that the 98 generators in Enron's example would not be eligible to

[10] Enron at 3.

recovery fuel cost during these intervals, since they did not actually supply any net energy to the spot markets. Thus, under the ISO's approach, as applied to Enron's example, only the one generator that is a net seller would recover a fuel cost allowance for its 1,000 MWh of net sales, while these costs would be allocated to one entity that is a net buyer of 1,000 MWh.

As these examples indicate, if the Commission does not require fuel cost allowances to be calculated based on the net sales of generators, then allocating fuel cost allowances to these generators based on net purchases clearly create an inequitable result. Thus, if the Commission intends to allow suppliers to base fuel cost allowances on *gross* sales rather than net spot market energy provided, then any purchases of spot market energy by suppliers should be treated in a similar manner, so that each supplier's gross purchases are used to determine the allocation of fuel cost allowances. Again, the equity of this approach can be illustrated using the hypothetical example provided by Dynegy and Williams. In that example, if the generator is eligible to recover a gas allowance for the 10 MWh of instructed energy provided by Unit A, the generator should also be subject to gas cost allocation charges for the entire 12 MWh of negative uninstructed energy purchases from Unit B. Thus, if gas cost allowances are based on generators *gross* rather than *net* sales, then any purchases made by generators should also be subject to allocation of fuel cost allowances on a gross basis.

If the Commission determines that fuel cost allowances should be based on gross sales, then the ISO believes that the most appropriate solution would be to allocate fuel costs based on net purchases only for those entities that do not have an approved fuel cost allowance. A simple decision rule that could be used by the ISO to implement this approach would be as follows:

1) For any entity having a fuel cost allowance approved, any purchases by that entity would be included in the fuel cost allocation based on gross purchases, in order to be consistent with the manner in which the entities' fuel cost allowance was calculated.
2) For an entity not having any fuel cost allowance submitted or approved (e.g. the major California utilities, other non-thermal generators, and marketers), the ISO will allocate fuel costs based on net purchases.

This approach would prevent the inequity that would result from allocating fuel costs based on gross purchases to utilities that were required to sell through the PX during a portion of the Refund Period, while still allocating fuel allowance costs to suppliers consistent with the manner in which those costs were calculated.

What Williams and Dynegy really seem to be advocating is that any entity that does not serve load should not be assessed any fuel cost allocation charges. Again, Dynegy and Williams' own example illustrates the inequity of their approach. In that example, the generator actually purchased *more* spot market energy than it provided (*i.e*. 12 MWh negative uninstructed energy purchased from Unit B less 10 MWh instructed energy provided by Unit A equals a net purchase of 2 MWh). However, under the approach proposed by Dynegy and Williams, this hypothetical generator would recover gas costs associated with the

10 MWh of instructed energy delivered from Unit A, but would not bear any of the gas costs associated with the purchases made by Unit B. Instead, load-serving entities would be required to pay for gas costs associated with the 12 MWh of negative uninstructed energy purchases made from Unit B in this hypothetical example. Thus, the Williams/Dynegy approach would have load-serving entities pay for gas costs *in excess* of the quantity of spot market energy that they actually relied upon to meet load, while suppliers who were net negative deviators (and thus net purchasers) during certain intervals would be excused from any assignment of fuel allowance costs. The flawed premise of the Dynegy/Williams approach is that purchases of negative uninstructed energy should not be treated as purchases for purposes of fuel cost allocation, despite the fact that these transactions are treated and accounted for as purchases in the ISO settlements and billing system. There is no reason to make such a distinction – negative deviators, such as the hypothetical Unit B in the Dynegy/Williams example, directly contributed to the need for additional spot market energy purchases, and thus higher fuel allowance costs, by failing to generate as indicated. Under these circumstances, it is entirely appropriate that such suppliers are allocated a portion of their own fuel cost allowance. Dynegy/William's argument is inconsistent with the manner in which the ISO Markets operate, and principles of cost causation, and should therefore be rejected.[11]

[11] The ISO does, however, acknowledge that Dynegy and Williams are correct that there is a typographical error on page 5 of Attachment A of the ISO's compliance filing, and that "Charge Code = 401" should read "Charge Code = 407." *See* Dynegy/Williams at 4.

C. Allocation of Fuel Cost Allowances to Marketers

Sempra argues that power marketers should not be forced to pay any portion of the fuel cost allowances to be paid to generators, on the grounds that marketers cannot submit their own fuel cost allowances unless they have a specific contractual arrangement with a generator. Sempra at 2. Again, however, a simple example reveals that not requiring marketers to bear a portion of fuel cost allowances associated with for any spot market purchases they made in the PX or ISO Markets inevitably requires load-serving entities to pay for the gas associated with purchases made by marketers, so that load-serving entities would end up paying for gas costs in excess of the quantity of spot market energy that they actually relied upon to meet load. Assume, for example, that during one hour a load-serving entity purchased 100 MW of energy in the PX to serve load within the ISO system, and a marketer also purchased 100 MW of energy from the PX and either exported this energy or transferred it through an inter-SC trade to meet a bilateral agreement. If the marketer is not required to pay the gas cost allowance for such purchases, the gas cost allowance for the 100 MW would simply be passed on to the load-serving entity, which would be allocated gas costs associated with total 200 MW of power sold in the PX, despite having purchased just 100 MW during that hour. This result is clearly inequitable, and the Commission should therefore reject Sempra's proposal.

D. Transmission Losses

AEPCO argues that out-of-state suppliers should not be assessed any share of the fuel cost allowance to cover transmission losses associated with imports to the ISO system.[12] AEPCOs concern appears to stem from the fact that when transmission losses associated with import schedules are calculated as part of the ISO settlement process, these transmission losses may result in a supplier having a relatively small negative uninstructed deviation.[13] The ISO's proposed approach would treat this negative uninstructed deviation in the same manner as any other uninstructed deviation, and allocate a portion of fuel cost allowances to this negative deviation as a purchase of spot energy from the ISO imbalance market. AEPCO objects to being assessed for any a portion of fuel cost allowances to this negative deviation on the grounds that these losses are essentially "forced purchases" of real time energy, and that transmission losses should be excluded from the ISO's "load" for purposes of allocating fuel cost allowances.[14]

The ISO objects to AEPCO's requested exclusion for transmission losses on the grounds that doing so would simply shift the fuel cost allowance charges actually associated with these losses to other participants. Transmission losses represent a real source of demand for real time energy in the ISO system, and "excluding" these losses from the ISO's "load" for purposes of allocating fuel

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[12] AEPCO at 3-5.

[13] For example, assume that AEPCO imports 100 MW to the ISO system for a sale into the PX over an inter-tie for which transmission losses are calculated at 3.5%, and has no other transactions, load or resources that hour. As part of the ISO settlement process, the losses of 3.5 MW will be applied to the 100 MW import schedule, so that AEPCO would be assessed negative uninstructed energy charges for 3.5 MW.

[14] AEPCO at 3-4.

allowance costs would not change the fact that the ISO relied upon additional purchases of imbalance energy to compensate for these losses, and would not reduce the amount of imbalance energy for which generators will recover fuel cost allowances. Thus, AEPCO's proposal to exclude uninstructed energy purchases associated with transmission losses would unfairly shift the fuel cost allowance charges actually associated with these losses to other participants, and should therefore be rejected.

E. Impact of Settlements on the Allocation of Fuel Costs

In its comments, Enron maintains that the ISO's proposed methodology should be rejected because it fails to take into account the impact of fuel cost allowance settlements. Enron at 3-4. The Commission should reject Enron's argument. First, Enron's argument is misplaced because the Commission did not require the ISO to take into account fuel cost allowance settlements in creating a proposed allocation methodology. Moreover, it would be inappropriate to make the ISO responsible for creating a methodology to allocate settled fuel cost allowances, because the ISO is not a party to any of these settlements. The ISO has worked with various settling parties to resolve implementation issues surrounding those settlements, nevertheless, it is the parties to the settlement themselves who are in the best position to develop and propose a methodology for allocating fuel cost amounts in those settlements, because those parties have the most expertise with the terms and operation of those settlements.

F. Impact of the ISO's Proposal

CSG argues that accepting the ISO's proposed allocation methodology would be premature because none of the fuel cost data has been filed or audited yet. CSG at 5-6. CSG maintains that it is "difficult to see the impact of the CAISO's proposal" without first reviewing that data. Even if CSG is correct, however, this is not a compelling reason to withhold approval of the ISO's proposal. The actual financial impact of the ISO's proposal is not determinative of its reasonableness. The Commission should reject this "ends justify the means" approach. Moreover, the implicit result of CSG's contention, that audited fuel cost must be "in hand" prior to approving an allocation methodology, would lead to an additional delay in completing the refund rerun process.

II. CONCLUSION

For the reasons set forth herein, the ISO respectfully requests that the Commission accept this answer and adopt the ISO's proposed methodology for allocating fuel cost allowances, as set forth in its August 17, 2004 compliance filing.

Respectfully submitted,

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Dated: September 14, 2004

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list for the captioned proceeding, in accordance with Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, CA, on this 14th day of September, 2004.

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Gene L. Waas

Format for Fuel Cost Allowance Submissions

Background

The Commission's May 12, 2004 Order Addressing Fuel Cost Allowance Issues, ("Fuel Cost Order")[15] clarified issues pertaining to the fuel cost allowance filings of sellers into spot energy markets operated by the California Independent System Operator ("ISO)" and California Power Exchange ("PX"). In addition, the Fuel Cost Order directs sellers to have their fuel cost allowance claims verified by an independent auditor, and then submitted directly to the ISO.[16] The Fuel Cost Order goes on to direct sellers to clearly identify within their fuel cost allowance claims a list of specific items, including:

i. Fuel purchases ranked by term from shortest to longest that indicates price, term, date and quantity for each transaction;

ii. Marginal heat rate by unit (to be the same as that used by the ISO);

iii. MW-hours by unit sold to the ISO/PX over the applicable interval (to be the same as that used by the ISO);

iv. Average daily fuel cost per MMBtu, a demonstration of how this calculation was derived based on the fuel supply stack, and supporting work papers; and

v. Overall fuel cost allowance amount, on a monthly basis, to offset the refund owed by each generator.

The Fuel Cost Order further specified that all calculations must be provided in a usable electronic spreadsheet format.

On September 2, the Commission issued an Order On Auditor Selection And Request For Waiver And Clarifying Audit Issues ("Audit Order")[17] requiring that:

> … the CAISO should make available within 10 days of the issuance of this order, either by posting on its website or making generally available to all generators who filed fuel cost allowance claims, the required format for the generators' fuel cost allowance submissions.

Pursuant to these orders, the ISO is providing the following more detailed description of the required format for the generators' fuel cost allowance submissions.

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[15] *Order Addressing Fuel Cost Allowance Issues*, 107 FERC ¶ 61,166 (2004), herein referred to as "Fuel Cost Order".

[16] Fuel Cost Order at P 1.

[17] *Order On Auditor Selection And Request For Waiver And Clarifying Audit Is*sues, 108 FERC ¶ 61,219 (2004)," herein referred to as "Audit Order".

Sales of Energy in PX Day Ahead Market

Table 1 provides a description of specific data and calculations that should be provided for fuel cost allowance submission for sales in the PX Day Ahead market in accordance with the methodology and data requirements outlined in the Fuel Cost Order.

As indicated in the Fuel Cost Order, fuel cost allowance submissions must clearly identify:

> MW-hours by unit sold to the ISO/PX over the applicable interval (to be the same as that used by the ISO); [18]

For PX Day Ahead market sales, the applicable interval used by the ISO is *hourly,* so that all fuel cost allowance submissions must show all calculations for each unit on an hourly basis

As indicated in the Fuel Cost Order, fuel cost allowance submissions must also clearly identify:

> Marginal heat rate by unit (to be the same as that used by the ISO); [19]

Heat rates used for each unit by the ISO in calculation of final MMCPs in these proceedings are the non-monotonic incremental heat rates at the unit's acknowledged operating target (AOT), as directed in the Commission's December 12, 2002 Order "December 12 Refund Order").[20] Calculations of the AOT in for the refund proceedings were made for each unit on a 10-minute interval basis. For purposes of calculating marginal heat rates for sales in the hourly PX market, each unit's hourly non-monotonic heat rates made be calculated based on either: (1) the unit's average of non-monotonic heat rates for each 10-minute interval used by ISO in calculating MMCP, or (2) the unit's non-monotonic heat rates at the average AOT over the six 10-minute intervals for each hour.

Since only spot market sales that were actually mitigated are eligible for inclusion in the gas cost allowance calculations[21], any sales made through the Block Forward Market (BFM), which were excluded from mitigation in refund calculations, must also be excluded from the total amount of sales made by a generator in the PX Day Ahead market included in fuel cost allowance calculations.

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[18] Fuel Cost Order at P 76, item (iii).

[19] Fuel Cost Order at P 76, item (ii).

[20] *Certification of Proposed Findings on California Refund Liability, Docket Nos. EL00-95-045, et a*l. (December 12, 2002). The Fuel Cost Order at Paragraph 51 also specifies that "the incremental heat rates are most appropriate for use in the fuel cost allowance calculations."

[21] Fuel Cost Order at P 37.

The Fuel Cost Order also directed the ISO to devise a methodology for allocating fuel cost allowance costs to buyers of spot market energy.[22] The ISO's compliance filing made pursuant to this directive provided a methodology based on the understanding that fuel cost allowances will be calculated based on generator's total *net* sales of energy in the spot markets during each time interval (i.e. gross sales attributed to the generator's portfolio thermal unit, less any purchases made by the generator during the same time interval in the PX and ISO spot markets. Thus, the cost allocation methodology proposed by the ISO also provides that fuel cost allowances be allocated be based on net purchases of spot market energy during each time period.[23] Further discussion of the rationale and issues of basing fuel cost allowance calculations and allocations on net versus gross sales is being provided in the ISO's response to comments on the ISO's proposed methodology due to be filed with the Commission on September 14, 2004.

Sales of Instructed Energy in ISO Market

Table 2 provides a description of specific data and calculations that should be provided for any fuel cost allowance submission for sales of Instructed Energy in the in the ISO Real Time Market, in accordance with the methodology and data requirements outlined in the Fuel Cost Order.

As indicated in the Fuel Cost Order, fuel cost allowance submissions must clearly identify:

> MW-hours by unit sold to the ISO/PX over the applicable interval (to be the same as that used by the ISO); [24]

For the ISO real time energy markets, the applicable interval used by the ISO is each *10-minute interval* within each hour.

As indicated in the Fuel Cost Order, fuel cost allowance submissions must also clearly identify:

> Marginal heat rate by unit (to be the same as that used by the ISO); [25]

Heat rates for each unit used by the ISO in calculation of final MMCPs in these proceedings are the non-monotonic incremental heat rates at the unit's AOT, as directed in the Presiding Judge's December 12 Refund Order, and confirmed in the Commission's March 26 Order.[26]

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[22] Fuel Cost Order at P 60.

[23] Compliance Filing of California Independent System Operator Concerning the Allocation of Fuel Cost Allowance, filed August 17, 2004, herein after referred to as "Cost Allocation Filing'.

[24] Fuel Cost Order at P 76, item (iii).

[25] Fuel Cost Order at P 76, item (ii).

[26] *Certification of Proposed Findings on California Refund Liability, Docket Nos. EL00-95-045, et a*l. (December 12, 2002). Order on Proposed Findings on Refund Liability, 102 FERC ¶ 61,317 (2003) at P

As noted in Table 2, during the "soft cap" period starting Dec. 8, 2000, the final settlement quantity and price for sales of Instructed Energy over the $250/$150 soft caps must be calculated by combining final Billable Quantities and Billable Prices for both 401 and 481 chares types. In testimony during refund proceedings, generators have indicated they are able to perform this calculation based on ISO settlement records. However, the ISO stands ready to provide these data to the Commission and to generators upon request in order to facilitate completion and verification of Fuel Cost Allowance submissions.

Just as the Commission has required for calculation of average daily fuel costs, any fuel cost allowance submission for sales of Instructed energy sales in the ISO real time market should also include "a demonstration of how this calculation was derived" and "supporting work papers".[27]

Sales of Uninstructed Energy in ISO Market

Tables 3 and 4 provide a description of specific data and calculations that should be provided to the ISO for any fuel cost allowance submission for sales of Uninstructed Energy (UE) in the in the ISO Real Time Market in accordance with the methodology and data requirements outlined in the Fuel Cost Order.

The format of Tables 3 and 4 reflect the fact that the ISO settlement system pays or charges each participant for UE based on whether the net deviation between scheduled and metered data for the participant's entire portfolio of supply and demand schedules is positive or negative. For example, if a generator has 12 MW of positive uninstructed energy from one unit, but 10 MW of negative uninstructed energy from another unit, the ISO settlement system treats this as a net sale of 2 MW of uninstructed energy to the ISO system. Thus, using this example, the format of Tables 3 and 4 require the generator to identify 2 MW of uninstructed energy from one or more specific units that had a positive deviation from their schedule, and calculate the fuel required to produce this 2 MW based on the incremental heat rates of these units.

As indicated in the Fuel Cost Order, fuel cost allowance submissions must clearly identify:

> MW-hours by unit sold to the ISO/PX over the applicable interval (to be the same as that used by the ISO); [28]

For sales of uninstructed energy in the ISO's real time energy markets, the applicable interval used by the ISO is each *10-minute interval* within each hour.

5B. The Fuel Cost Order at Paragraph 51 also specifies that "the incremental heat rates are most appropriate for use in the fuel cost allowance calculations."

[27] Fuel Cost Order at P 76, item (iv).

[28] Fuel Cost Order at P 76, item (iii).

As indicated in the Fuel Cost Order, fuel cost allowance submissions must also clearly identify:

Marginal heat rate by unit (to be the same as that used by the ISO); [29]

Heat rates for each unit used by the ISO in calculation of final MMCPs in these proceedings are the non-monotonic incremental heat rates at the unit's AOT, as directed in the Commission's December 12 Refund Order.[30]

Just as the Commission has required for calculation of average daily fuel costs, any fuel cost allowance submission for sales of Uninstructed Energy in the ISO Real Time Market should also include "a demonstration of how this calculation was derived" and "supporting work papers".[31]

[29] Fuel Cost Order at P 76, item (ii).

[30] *FERC Certification of Proposed Findings on California Refund Liability in Docket Nos. EL00-95-045, et a*l. issued December 12, 2002. The Fuel Cost Order at 51 also specifies that "the incremental heat rates are most appropriate for use in the fuel cost allowance calculations."

[31] Fuel Cost Order at P 76, item (iv).

Table 1. Format for Fuel Cost Allowance Submissions for Mitigated PX Energy Sales

Col. Ref	Variable	Description
A	Opr_dt	Operation Date
B	Opr_hr	Operating Hour (hour ending)
C	PX_ID	Participant ID used in PX settlement records (Short_Name)
D	Unit_ID	ISO unit identification code
E	DA_MW	Final Day Ahead Energy schedule for unit for hour
F	QTY	Quantity (MWh) of generator's PX sales during hour attributed to unit
G	PRICE	Price ($/MWh) for PX sales attributed to unit in hour
H	REV	Revenues from transaction prior to price mitigation (F x G)
I	MMCP	Mitigated Market Price (Hourly)
J	QTY_M	Quantity of participant's PX sales during hour attributed to unit in hour subject to price mitigation (F if I < G; otherwise 0)
K	REV_M	Revenues from transaction after price mitigation (F x Min(G, I))
L	IHR	Incremental heat rate for unit during hour for mitigated sales (MMBTU/MW)
M	FUEL	Calculated incremental fuel input (consumption) for mitigated sales of unit during hour (J x L)
N	FUEL_PRC	Avg. daily cost ($/MMBTU) for fuel input (consumption) for mitigated spot market sales by generator during operating day.
O	FUEL_CST	Total cost ($) for fuel input (consumption) for mitigated sales of unit during hour. (M x N)
P	FCA	Fuel Cost Allowance (0 if O < K ; otherwise Min (O – K, H – K)

Notes:

[1.F] Should not exceed units Day Ahead energy schedule for hour. The sum of Table 1, Column F for all units identified as providing a portion of total sales of PX energy from a generator's portfolio should add up to total sales of PX energy from a generator's portfolio during hours that is attributable to total amount of energy scheduled in Hour Ahead market by a generator's thermal units (taking into account PX sales met by other supply sources, such as inter-SC trades from other suppliers, imports and purchases from PX during same hour).

[1.L] Marginal heat rates used by ISO = Non-monotonic incremental heat rate of unit at AOT, as defined in calculations of MMCP. Hourly non-monotonic heat rates may be calculated based on average of non-monotonic heat rates for each 10-minute interval used by ISO in calculating MMCP, or non-monotonic heat rate at average AOT for hour.

[1.N] As confirmed by the independent auditor based on generator's fuel purchase data, and total fuel consumption associated with spot market sales in PX and ISO that were mitigated (i.e. had a transaction price < MMCP) during operating day. Total fuel consumption for mitigated spot market sales during each operating day used in auditors calculation must equal sum of FUEL columns for each generating unit reported in Tables 1, 2 and 4 (representing unit-level data for sales of PX, ISO Instructed Energy and ISO Uninstructed Energy, respectively, during each hour/10-minute interval of operating day).

Table 2. Format for Fuel Cost Allowance Submissions for Mitigated ISO Instructed Energy (IE) Sales

Col. Ref.	Variable	Description
A	Opr_dt	Operation Date (TRADING DATE in ISO Settlement records)
B	Opr_hr	Operating Hour (TRADING HOUR in ISO Settlement records)
C	Rt_Int	10-minute interval, 1-6 (TRADING INT in ISO Settlement records)
D	SC_ID	Participant ID for transaction from ISO settlement records (Short Name for SC corresponding to numerical Business Associate ID).
E	Unit_ID	ISO unit identification code (LOCATION ID in ISO Settlement records)
F	E_TYPE	Energy type (SP=Spin, NS=Non-spin, SE=Supplemental energy, OOM=out-of-market)
G	CHRG_TYPE	401 = instructed energy priced at or below the (soft) price cap, 481 = instructed energy priced above the (soft) price cap
H	QTY	Quantity (MWh) of Instructed Energy sold through transaction during interval from unit (from BILLABLE QUANTITY in ISO Settlement records)
I	PRICE	Price ($/MWh) for Instructed Energy (IE) sold through transaction during interval from unit (from PRICE in ISO Settlement records)
J	REV	Revenues from transaction prior to price mitigation (H x I).
K	MMCP	Mitigated Market Price (for 10-minute interval)
L	QTY_M	Quantity of participant's UE sales from transaction during 10-minute interval subject to price mitigation (H if K < I; otherwise 0)
M	REV_M	Revenues from transaction after price mitigation (H x Min (I, K))
N	IHR	Incremental heat rate for unit during 10-minute interval for mitigated sales (MMBTU/MW)
O	FUEL	Calculated incremental fuel input (consumption) for mitigated sales of unit during interval (L x N)
P	FUEL_PRC	Avg. daily cost ($/MMBTU) for fuel input (consumption) for mitigated spot market sales by generator during operating day.
Q	FUEL_CST	Total cost ($) for fuel input (consumption) for mitigated sales of unit during interval (O x P)
R	FCA	Fuel Cost Allowance (0 if Q < M ; otherwise Min (Q – M, J – M)

Notes:

[1.G] During the "soft cap " period starting Dec. 8, 2000, the final settlement quantity and price for sales of Instructed Energy over the $250/$150 soft caps must be calculated by combining final Billable Quantities and Billable Prices for both 401 and 481 chares types. In testimony during refund proceedings, generators have indicated they are able to perform this calculation based on ISO settlement records. However, the ISO stands ready to provide these data to the Commission and generators upon request in order to facilitate completion and verification of fuel cost allowance submissions.

Table 3. Format for Fuel Cost Allowance Submissions
for Mitigated ISO Uninstructed Energy (UE) Sales (SC Portfolio Level)

Col. Ref	Variable	Description
A	Opr_dt	Operation Date (TRADING DATE in ISO Settlement records)
B	Opr_hr	Operating Hour (TRADING HOUR in ISO Settlement records)
C	Rt_Int	10-minute interval 1-6 (TRADING INT in ISO Settlement records)
D	SC_ID	Participant ID for transaction from ISO settlement records (Short Name for SC corresponding to numerical Business Associate ID).
E	Region_ID	Region ID from ISO uninstructed energy settlement records used to indicate whether uninstructed energy for each was settled by netting each SCs portfolio on a system-wide or zonal basis (in hours of real time congestion). If real time congestion, 1= NP15 and 2=SP15. If no congestion, 1= uniform system prices/charges.
F	E_TYPE	UE = Uninstructed energy
G	CHRG_TYPE	407 = Uninstructed energy
H	QTY	Quantity (MWh) of Uninstructed Energy sold through transaction during interval by SC in ISO system or in zone (if real time energy market split zonally). From BILL_QTY for SC during interval in SS_SETTLEMENT_DETAILS table.
I	PRICE	Price ($/MWh) for Uninstructed Energy (UE) sold through transaction during interval by SC (from PRICE in ISO Settlement records)
J	REV	Revenues from transaction prior to price mitigation (H x I).
K	MMCP	Mitigated Market Price (for 10-minute interval)
L	QTY_M	Quantity of participant’s UE sales from transaction during interval subject to price mitigation (H if K < I; otherwise 0)
M	REV_M	Revenues from transaction after price mitigation (H x Min(I, K))
N	FUEL	Calculated incremental fuel input (consumption) for mitigated sales of UE from SC’s portfolio during interval. Sum of Column I in Table 4 for all units identified as providing a portion of SCs total UE sales during interval.
O	FUEL_PRC	Avg. daily cost ($/MMBTU) for fuel input (consumption) for mitigated spot market sales by generator during operating day.
P	FUEL_CST	Total cost ($) for fuel input (consumption) for mitigated sales of unit during interval (N x O)
Q	FCA	Fuel Cost Allowance (0 if P < M ; otherwise Min (P – M, J – M)

Notes:

[3.G] Sum of Table 4, Column G for all units identified as providing a portion of total sales of uninstructed energy from generators portfolio should add up to total sales of uninstructed energy from a generator’s portfolio during interval as reported in Table 3, Column H.

[4.I] Sum of Table 4, Column I for all units identified as providing a portion of total sales of uninstructed energy from a generator’s portfolio should add up to total fuel input/consumption associated with total uninstructed energy from a generator’s portfolio during interval as reported in Table 3, Column N.

Table 4. Format for Fuel Cost Allowance Submissions for Mitigated ISO Uninstructed Energy (UE) Sales (Unit Level)

Col. Ref.	**Variable**	**Description**
A	Opr_dt	Operation Date (TRADING DATE in ISO Settlement records)
B	Opr_hr	Operating Hour (TRADING HOUR in ISO Settlement records)
C	Rt_Int	10-minute interval (TRADING INT in ISO Settlement records)
D	SC_ID	Participant ID for transaction from ISO settlement records (Short Name for SC corresponding to numerical Business Associate ID).
E	Unit_ID	**ISO unit identification code (LOCATION ID in ISO Settlement records)**
F	ZONE_ID	ISO Congestion zone in which resource is located (NP15,SP15,ZP26).
G	UE	Uninstructed energy (MWh) from unit for interval from ISO settlement data (SS_UNINSTR_ENERGY_DETAILS table provided with ISO settlement data).
H	IHR	Incremental heat rate for unit during interval for mitigated sales (MMBTU/MW)
I	FUEL	Calculation of incremental fuel input (consumption) for portion of SC's mitigated uninstructed energy sales attributed to unit during interval (G x H)

Notes:

[4.G] Sum of Table 4, Column G for all units identified as providing a portion of total sales of uninstructed energy from a generator's portfolio should add up to total sales of uninstructed energy from generators portfolio during interval as reported in Table 3, Column H.

[4.I] Sum of Table 4, Column I for all units identified as providing a portion of total sales of uninstructed energy from a generator's portfolio should add up to total fuel input/consumption associated with total uninstructed energy from a generator's portfolio during interval as reported in Table 3, Column N.

Illustrative Example of Fuel Cost Allowance Submission for Mitigated PX Energy Sales

Exhibit 1 illustrates the basic format required for the generators' fuel cost allowance submissions based on the general methodology and information requirements outlined in the Fuel Cost Order.[32] This simplified example represents a hypothetical fuel cost allowance submission for sales by a generator in the PX Day Ahead spot market. Previous sections of this document provide a more detailed description of the specific data items to be provided for all hourly sales in the PX market, as well as sales of instructed and uninstructed the ISO's real time imbalance market for each 10-minute interval.

Column A and B of Exhibit 1 show initial sales quantities and prices (i.e. prior to price mitigation) in the PX market for a hypothetical generating unit over each hour of one operating day. As shown in Figure 1, the supplier has sold the following:

- 100 MW at $50 during eight off-peak hours (1-6 and 23-24)
- 200 MW at $100 for eight peak hours (7 to 11 and 19-22)
- 500 MW at $250 for eight super peak hours (12 to 18)

After developing a list of initial spot market transaction prices and quantities, the next step in calculating fuel cost allowances in accordance with the Fuel Cost Order is to determine hours in which sales were mitigated, and to screen out all spot market sales that were not mitigated from any further fuel cost allowance calculations. As shown in Columns C and D, sales during the 8 off-peak hours (1-6 and 23-24) of this example were not subject to price mitigation and are therefore screened out of further fuel cost allowance calculations.

The next step in the methodology for calculating fuel cost allowances in accordance with the Fuel Cost Order is to determine the gas input or consumption associated with spot market sales that were mitigated. As shown in Exhibit 1, this is done by multiplying the total quantity of the spot market energy transaction that was mitigated (Column D) by the unit's incremental heat rate for producing that spot market energy (Column F) in order to derive the total gas input or consumption associated with spot market sales that were mitigated.

Because gas purchases are made on a daily basis or longer, the Fuel Cost Order requires the average cost of gas per MMBtu or price paid by the generator to be calculated on a daily basis, and confirmed by an independent auditor, based on the generator's gas purchase data and the total daily gas consumption associated with spot

[32] NOTE: Due to simplifications used in this example, the column identifiers (A-J) used in this example do not correspond to column identifiers (A-O) of the format required for actual Fuel Cost Allowance submissions for sales in the PX market.

market sales that were mitigated. As shown in Exhibit 1, the gas incremental consumption of the unit in this example associated with spot market sales that were mitigated is 51,200 MMBtu (see daily total for Column G). As shown in Column H, this example assumes that the average daily cost of gas per MMBtu on this day, as confirmed by the auditor, equals $9 per MMBtu.[33]

The average daily gas price calculated should then be applied on an hourly basis to mitigated sales in the PX to determine any gas cost allowance the generator is eligible to recover. This step involves comparing the total revenues received for each mitigated transaction after price mitigation (Column E) to the total gas costs associated with each mitigated spot market transaction (Column I). [34] If revenues after price mitigation for any individual transaction (Column E) do not allow the generator to recover the gas costs associated with these mitigated spot market transaction (Column I), then the generator is eligible to recover this difference through the gas allowance (Column J). In this example, the generator is eligible to receive a gas allowance for the 200 MW sold during each eight peak hours (7 to 11 and 19-22), but is not eligible for a gas cost allowance for sales during the super peak hours (12 to 18). During these super peak hours, the revenues received for these sales after price mitigation still allowed the generator to recover gas costs associated with these sales, so that there is no fuel cost allowance during these hours.

In addition, the Fuel Cost Order indicates that the total compensation paid for any transaction (after price mitigation) *plus* any Fuel Cost Allowance cannot exceed the initial transaction price prior to mitigation.[35] Thus, the formula for calculation of the Fuel Cost Allowance for PX sales provided in Table 1 Column 0 includes a limitation that the Fuel Cost Adjustment for any transaction not exceed the difference between the initial transaction price and the mitigated transaction price. This limitation is not relevant in this example, but is included in the formulas for calculation of the Fuel Cost Allowance for each spot market energy transaction as set forth above in Tables 1, 2 and 3.

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[33] As indicated in the Fuel Cost Order, in addition to providing the average daily fuel cost per MMBtu used in this example, fuel cost allowance submissions must include a listing of all "fuel purchases ranked by term from shortest to longest that indicates price, term, date and quantity for each transaction" and "a demonstration of how this calculation was derived based on the fuel supply stack, and supporting work papers". (Fuel Cost Order at P 76, items (i) and (iv)).

[34] Fuel Cost Order at P 37, indicating that one of the criteria that must be met to show that a transaction is eligible for inclusion in any fuel cost allowance whether "the fuel that was burned was more or less expensive than the MMCP".

[35] Fuel Cost Order at PP 55and 56, indicating that the Commission granted the proposed CA Parties' proposed condition that "fuel cost allowances should not result in generators recovering more than the pre-mitigated amount."

Exhibit 1. Illustrative Calculation of Fuel Cost Allowance Calculation for PX Sales from Unit

	A	B	C	D	E	F	G	H	I	J
Hour	MWh	Price	MMCP	Mitigated Sales	Revenues After Mitigation	Incremental Heat Rate	Gas Input (MMBtu)	Avg. Gas Cost ($/MMBtu)	Total Gas Cost	Gas Allowance
1	100	$50	$60	0	n/a	n/a	0	$9	n/a	n/a
2	100	$50	$60	0	n/a	n/a	0	$9	n/a	n/a
3	100	$50	$60	0	n/a	n/a	0	$9	n/a	n/a
4	100	$50	$60	0	n/a	n/a	0	$9	n/a	n/a
5	100	$50	$60	0	n/a	n/a	0	$9	n/a	n/a
6	100	$50	$60	0	n/a	n/a	0	$9	n/a	n/a
7	200	$100	$75	200	$15,000	9,000	1,800	$9	$16,200	$1,200
8	200	$100	$75	200	$15,000	9,000	1,800	$9	$16,200	$1,200
9	200	$100	$75	200	$15,000	9,000	1,800	$9	$16,200	$1,200
10	200	$100	$75	200	$15,000	9,000	1,800	$9	$16,200	$1,200
11	200	$100	$75	200	$15,000	9,000	1,800	$9	$16,200	$1,200
12	500	$250	$100	500	$50,000	10,000	5,000	$9	$45,000	$0
13	500	$250	$100	500	$50,000	10,000	5,000	$9	$45,000	$0
14	500	$250	$100	500	$50,000	10,000	5,000	$9	$45,000	$0
15	500	$250	$100	500	$50,000	10,000	5,000	$9	$45,000	$0
16	500	$250	$100	500	$50,000	10,000	5,000	$9	$45,000	$0
17	500	$250	$100	500	$50,000	10,000	5,000	$9	$45,000	$0
18	500	$250	$100	500	$50,000	10,000	5,000	$9	$45,000	$0
19	200	$100	$75	200	$15,000	9,000	1,800	$9	$16,200	$1,200
20	200	$100	$75	200	$15,000	9,000	1,800	$9	$16,200	$1,200
21	200	$100	$75	200	$15,000	9,000	1,800	$9	$16,200	$1,200
22	200	$100	$75	200	$15,000	9,000	1,800	$9	$16,200	$1,200
23	100	$50	$60	0	n/a	n/a	0	$9	n/a	n/a
24	100	$50	$60	0	n/a	n/a	0	$9	n/a	n/a
Total	6,100			5,300	$485,000		51,200			$10,800

Column	Notes
A	Total MWh sales from unit
B	Original transaction price (MCP or bid price for sales above softcap)
C	Mitgated Market Price
D	Mitigated sales quantity from unit (A if C > B ; otherwise 0)
E	Revenues from mitigated sales after price mitigation (D x Minimum(B,C))
F	Incremental heat rate of unit for energy produced for mitigated sales
G	Incremental gas input (consumption) for mitigated sales (D x F)
H	Avgerage cost of gas during day per Mbtu (i.e. avg. price), as calculated by auditor based on generator's gas purchase data and quantity of gas burned for mitigated sales during day (Sum of Column G or 49,400 MMBtu)
I	Total gas costs for mitigated spot market sales (G x H)
J	Gas Allowance (I - E, if I > E ; otherwise 0)