Decision **PROPOSED DECISION OF ALJ MCKENZIE (Mailed 5/25/2005)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 E) for Rate and Line Extension Incentives for Conversion of Stationary Agricultural Internal Combustion Equipment to Electric Service.	Application 04-11-007 (Filed November 9, 2004)
Application of Southern California Edison Company (U 338-E) for Rate and Line Extension Incentives for Conversion of Stationary Agricultural Internal Combustion Equipment to Electric Service.	Application 04-11-008 (Filed November 9, 2004)

OPINION APPROVING ALL-PARTY SETTLEMENT AGREEMENT

TABLE OF CONTENTS

Title **Page**

OPINION APPROVING ALL-PARTY SETTLEMENT AGREEMENT

In this decision, we approve a settlement signed by all of the active parties in these proceedings, in which Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (Edison) seek authority to offer reduced rates and additional line extension allowances to agricultural customers who convert engines used for agricultural pumping from diesel fuel to electricity. Under the settlement, converting customers in PG&E's service area would receive a 20% reduction (and customers in Edison's service area a 12.5% reduction) from the otherwise applicable tariff for their engine use. The rate reductions would remain in effect for ten years, subject to escalation of the total average rate at 1.5% per year. Ratcheted demand charges would be eliminated from the rates for the new engines, and customers would not be subject to any deficiency charges. Customers electing to take advantage of this program would also receive one of three additional line extension allowances (referred to as "adders") depending on the size of the new electric engine, in addition to the standard extension allowances authorized by the respective PG&E and Edison tariffs. In consideration of the rate reductions and additional line extension allowances, converting customers would be required to destroy their old diesel engines and assign the resulting air emission credits they receive to the utilities for transfer to the California Air Resources Board (CARB) or the customer's local air pollution district.

Depending on the number of customers who sign up for the engine conversion program in the settlement, the program could result in a significant improvement in the air quality of the Sacramento and San Joaquin Valleys, which have some of the worst air quality in the nation. The program would remain open for two years, or until the capital expenditures associated with the line extensions (both standard allowances and adders) reached $27.5 million for PG&E and $9.17 million for Edison.

Because the engine conversion program in the settlement agreement is likely to result in meaningful air quality improvements, and because the concerns about the utilities' original proposals appear to be effectively addressed by (1) the $36.67 million capital cost limitation described above, and (2) the tying of the line extension adders to the size of the electric engine installed, we conclude -- in accordance with Rule 51.1(e) of our Rules of Practice and Procedure -- that the settlement is reasonable in light of the whole record, consistent with law and in the public interest. We will therefore approve it.

A. Procedural Background

1. The Applications

PG&E and Edison filed their applications on November 9, 2004. The applications were nearly identical, except that the average discounted electric rate a PG&E customer signing up for the engine conversion program would pay was $0.07539 per kilowatt-hour (kWh), while the average rate an Edison customer would pay was $0.06893 per kWh. PG&E proposed to offer a flat line extension adder of $32,935 to each customer signing up for the program, regardless of engine size, while Edison proposed to offer each customer signing up for its program a flat adder of $29, 942. These adders were based on the value of emissions of oxides of nitrogen (NO_X) used by CARB. PG&E and Edison also proposed that converting customers be required to assign the emission reduction credits obtained as a result of the conversion program to the utilities, who in turn would transfer them to CARB or the applicable air pollution control district.

PG&E and Edison both requested an exemption from Pub. Util. Code § 851 in connection with these transfers.

Each application also asserted that the proposed incentive rate would make a positive contribution to margin (CTM), and that because this was the case, the Commission should not reexamine either the CTM issue or the related issue of agricultural customers' marginal costs during the 10 years the discounted incentive rate would be in effect.

The principal benefit of the engine conversion program, the utilities argued, was that it would result in much cleaner air in the Sacramento and San Joaquin Valleys. The utilities cited data from CARB that diesel engines used for agricultural pumping presently account for approximately 23% of the NO_X emissions from stationary fuel combustion sources in the central valleys, and about 31% of the emissions of reactive organic gases (ROGs). The utilities also urged the Commission to act promptly on the applications, so that agricultural customers could take advantage of funds in the Carl Moyer Memorial Air Quality Standards Program[1] to help fund the conversions from diesel to electric engines.

---

[1] PG&E's testimony describes the Carl Moyer program as follows:

> "The Carl Moyer Memorial Air Quality Standards Program . . . is a grant program that provides funds for the purchase of cleaner-than-required engines and equipment, including agricultural pumps, in order to reduce air emissions [and ensure compliance with state and local implementation plans so as to avoid the loss of federal highway funds.]
>
> "In essence, the Carl Moyer Program provides taxpayer funding to reduce emissions from various sources, provided the associated emission reductions:
>
> - Are not required by regulation;

Footnote continued on next page

On November 16, the utilities filed a joint motion to consolidate the two proceedings. On November 24, 2004, the Agricultural Energy Consumers Association (AECA) filed petitions to intervene in both proceedings, which were accompanied by a motion for expedited consideration and decision.

2. The Protests of ORA and TURN

In mid-December 2004, both the Office of Ratepayer Advocates (ORA) and The Utility Reform Network (TURN) filed protests to the applications. In its protests,[2] ORA stated that it would propose a schedule after the first prehearing conference (PHC), and intended to conduct discovery and submit testimony on the following issues:

1. Whether the proposed rate reductions for customers installing new engines would really amount to 20%, and whether the proposed line extension adders were reasonable when compared with recent line extensions for other customers located in the same geographic areas.

2. Whether the additional electric load that would be created by converting diesel pumps to electric pumps would result in an imprudent increase in demand for electricity, "especially during a time of predicted shortage of both generation and transmission capacity."

- Meet a prescribed cost effectiveness based on a dollar per ton of reductions value; and
- Belong to the state or the air district providing the funding (that is, the reductions are not for sale as emission offsets)." (Exhibit 1, pp. 1-3 to 1-4.)

[2] ORA filed its protest to the PG&E application on December 12, 2004, and its protest to the Edison application on December 16, 2004.

3. Whether PG&E and Edison had considered the installation of "zero pollution" energy devices such as wind turbines and photovoltaic cells to handle the increased electric load that could be expected as a result of the engine conversion program.

In the joint protest of both applications that it filed on December 16, 2004, TURN raised similar issues, but with a somewhat different focus. First, TURN noted, significant capital costs would have to be incurred to connect the widely-dispersed agricultural pumping customers to the PG&E and Edison systems. These costs would be included in the rate base in the utilities' future general rate cases (GRCs), potentially resulting in a significantly increased revenue requirement that non-agricultural customers would have to bear. In addition, TURN noted, since pumping engines are used by agricultural customers only when there is a water shortage, it was possible that the new electric engines would be used much less often than was assumed in the utilities' calculations for the line extension adder. The effect of such a miscalculation would be to increase the revenue shortfall that eliminating deficiency billings – another aspect of both the PG&E and Edison proposals – seemed likely to bring about. (TURN Protest, pp. 2, 4.)

TURN also raised concerns about the effects of the engine conversion program on electric reliability. TURN noted that the conversion of diesel engines to electric service could increase load by as much as 400 megawatts (Mw), a serious concern in view of statements by some officials that "reserves may fall below 0% during 1-in-10 conditions in southern California during the summer of 2005." (*Id.* at 6.) At the same time, TURN pointed out, PG&E was proposing in Rulemaking (R.) 02-06-001 that customers in the Bay Area Air Quality Management District should be offered incentives to retrofit their existing diesel back-up generators, so that these generators could be run on days with high electric demand. (*Id.* at 6-7.)

Finally, TURN noted, the utilities did not furnish enough information about the incremental air quality benefits of their proposals to enable parties to determine whether the proposed adders and 20% rate reduction were reasonable. TURN also argued the Commission should consider whether additional conditions (such as reducing only off-peak agricultural rates) should be required before the engine conversion program was approved. Since discovery would be needed on these and the other issues TURN had raised, TURN urged that a PHC be held in January 2005, at which time the Commission should set a reasonable yet expeditious hearing schedule.

On December 23 and 27, respectively, PG&E and Edison filed brief replies to the protests, in which they suggested that technical workshops might be useful to work through some of the issues raised by the protests.

3. The Two Prehearing Conferences and the Technical Workshop

The first PHC in these proceedings was held on January 14, 2005. At this PHC, the assigned Administrative Law Judge (ALJ) provisionally granted the motion to consolidate the two applications, and then discussed with the parties how the many issues raised by the protests should be handled. After a short time, there was general agreement that, as PG&E and Edison had suggested, a workshop would be helpful.

The first of the issues raised by the ALJ was the amount of additional electric load that might result from the conversion program in 2005. After noting TURN's estimate that the conversion program could ultimately result in an additional 400 Mw of load in the combined geographic area served by Edison and PG&E (an estimate the utilities said they did not necessarily accept), the ALJ noted that additional load of such magnitude was a real concern, especially in view of the tight reserve margins expected in Southern California in the summer of 2005. The ALJ therefore asked the applicants and AECA how they intended to address it. AECA's counsel pointed out that owing to the leadtimes involved in constructing line extensions, ordering new engines, etc., the amount of additional load that could be expected in summer 2005 was small. (January 14 PHC Transcript, p. 32-34.) AECA counsel also noted that to the extent additional load in summer 2005 remained a concern, it could be addressed by capping the amount of new pumping load that would be permitted then, or -- as Edison had suggested -- by limiting the 20% discount rate to the off-peak period. (*Id.* at 33, 53.)

The second issue raised by the ALJ was the status of the marginal cost data on which PG&E and Edison had based their assertions that the proposed rate would result in a positive CTM.[3] Discussion revealed that while Edison's marginal cost proposals were the subject of a pending settlement supported by

---

[3] In its March 11, 2005 testimony, intervenor California Farm Bureau Federation (CFBF) gives the following explanation of marginal cost and its relationship to CTM:

> "The utilities have used the same approach that has been adopted in the past to approve Economic Development Rates (EDR) and Uneconomic Bypass rates; that is, to compare the marginal cost . . . for service to those customers to the expected revenue from the rates. Where the expected revenue is above the marginal cost . . ., the difference between the two is the estimated CTM." (Ex. 6, p. 4.)

most parties in A.02-05-004 (Phase 2 of Edison's 2003 GRC),[4] there was no imminent prospect of resolution with respect to PG&E's marginal cost proposals. The marginal cost data on which PG&E had based its engine conversion rate was an issue in A.04-06-024, the rate design proceeding that arose out of Phase 1 of PG&E's 2003 GRC, but a decision in A.04-06-024 was not expected before the end of 2005, and the parties did not appear close to a settlement. (January 14 Tr., pp. 75-76.) The ALJ stated that he thought the parties' differences over marginal costs and CTM were another appropriate subject for workshop discussion.

A third issue considered at the PHC was whether a ruling on the applications was, in fact, an urgent priority. AECA argued that an immediate decision was vital because investment decisions had to be made soon about the most cost-effective way of complying with the new air quality regulations for the Sacramento and San Joaquin Valleys required by SB 700.[5] TURN, on the other

---

[4] In D.05-03-022, the Commission adopted this settlement agreement. At pages 8-9 of the agreement (which is appended to the decision as Attachment A), the parties accepted the marginal cost proposals on which Edison based the rate at issue here.

[5] PG&E's testimony gives the following summary description of SB 700:

> "In response to the air quality problems in the central valleys, the California Legislature passed Senate Bill (SB) 700 [in 2003], . . . which amended the air pollution control requirements in the California Health and Safety Code for agriculture. SB 700 eliminated the agricultural operation permit exemption in its entirety and requires air districts to adopt best management practices to reduce or eliminate air pollution from agricultural operations. Hence, air districts are currently considering a number of new emission control requirements that are likely to go into effect in the near future. These new environmental requirements – which are not yet finalized and will vary by air district – will eventually require diesel engines in San Joaquin Valley, the South Coast, Sacramento County, the Mojave Desert, and Imperial County to implement 'Best Available Retrofit Control Technology'; that is, these

Footnote continued on next page

hand, argued that the continued availability of Carl Moyer Program funds ensured by AB 923[6] meant, as a practical matter, that the applications did not need to be processed on the highly expedited schedule sought by AECA and the utilities. Because the competing arguments seemed to depend on statutory requirements, the ALJ directed TURN to file a short brief by January 20, 2005 setting forth its interpretation of the applicable statutes, with AECA filing a reply brief on January 24.

To assist the parties in their workshop deliberations, AECA agreed to serve its testimony in advance of the workshop. On January 21, 2005, Richard

---

regulations are expected to require the installation of emission-control equipment, replacement with cleaner engines, or some other reduction technology." (Exhibit 1, p. 1-3.)

[6] As explained in TURN's January 20, 2005 Brief Regarding Legal Deadlines Related to Agricultural Engine Conversion, AB 923 (which became law in September 2004) extends the deadline for applying for Carl Moyer funds. The bill provides that the relevant funds shall be used to implement programs including "the new purchase, retrofit, repower, or add-on equipment for previously unregulated agricultural sources of air pollution . . . for a minimum of three years from the date of adoption of an agricultural rule or standard, or until the compliance date of that rule or standard, *whichever is later* . . ." (Emphasis added.) TURN's January 20 brief explains the effect of this and a related amendment as follows:

> "These amendments to the Carl Moyer Program essentially mean that agricultural customers will still be able to apply for funds to retrofit or replace their non-certified diesel engines with certified diesel or electric engines even after the new regulations go into effect on January 1, 2006. Those customers affected by Rule 4702 [the San Joaquin Valley Unified Air Pollution Control Districts's proposed regulation to comply with SB 700], for example, will be eligible for funds until January 1, 2009 or until the date they are required to comply with new emission limits. As mentioned above, the earliest compliance date for existing non-certified diesel engines is July 2007." (TURN Brief, p. 5.)

McCann, Ph.D., submitted testimony on behalf of AECA. In his testimony, Dr. McCann reiterated many of the utilities' arguments in favor of the engine conversion program, but also included a series of tables purporting to show (1) where the 5700 diesel pumps located in the San Joaquin and Sacramento Valleys were distributed, (2) the necessary "breakeven" point in electric rates that would induce agricultural customers to convert their diesel irrigation pumps to electric service, assuming a variety of crops and well-depths, and (3) how the net revenues that could be expected from electric pumping engines would exceed the costs of the line extensions, even with the adders.

The technical workshop was held on January 28, 2005. The principal topics discussed were the issues identified by the ALJ, as well as related questions such as whether any of the air emission credits obtained as a result of the engine conversion program should be sold to help reduce the future costs that ratepayers would have to bear. A follow-up session was held on February 1, 2005, during which the parties discussed questions related to the CTM issue, including (1) whether the marginal costs on which the CTM calculations were based should be required to include non-bypassable charges (NBCs), (2) whether the valuation of air quality benefits that formed the basis for the proposed line extension adder was reasonable, and (3) whether the adder was reasonable when compared with the line extension allowances available under the current agricultural rate schedules.

Pursuant to an agreement reached on January 14, a second PHC was held on February 4, 2005. The ALJ opened the second PHC by pointing out that since no stipulations had apparently resulted from the workshop, it would be necessary to set a hearing schedule. (PHC Tr. At 83.)

Counsel for AECA argued that based on his understanding of the workshop discussions, hearings were not necessary and briefing should be sufficient. In particular, he argued that the protestants should not be allowed to litigate the question of whether marginal cost calculations should be based on the New Customer Only (NCO) methodology or the rental methodology, because the Commission had consistently favored use of the NCO methodology in its decisions. (*Id.* at 85-89.) ORA argued, however, that these other decisions had dealt with revenue allocation issues, and that the utilities' proposals here presented a different question – *i.e.*, quantifying the cost of the conversion proposal -- for which the rental methodology was particularly appropriate. (*Id.* at 90-92.) After further discussion, the ALJ ruled that the NCO-versus-rental methodology issue could not be resolved on the record before him, and that the parties would be expected to address it in their testimony. (*Id.* at 92, 106.) The ALJ also rejected AECA's argument that ORA and TURN had had enough time for discovery, and should be required to specify immediately their factual differences with AECA and the utilities. (*Id.* at 92-94.)

Before proposing a schedule of his own, the ALJ asked ORA to present the schedule it had promised at the first PHC. ORA's proposal gave the intervenors six weeks to prepare their testimony and provided for hearings in early May, with final briefs to be submitted in early June. (*Id.* at 99-100.) However, the ALJ stated that in view of the considerations raised in AECA's January 24 response to TURN's brief on legal deadlines, such a schedule was too leisurely, and that the objective should be to issue a decision at the Commission's June 30, 2005 meeting. To this end, the ALJ proposed a schedule calling for the submission of intervenor testimony on March 4, hearings in early April, and the mailing of a draft decision on May 31. (*Id.* at 112.)

After some off-the-record discussion without the ALJ, the parties agreed that (1) the ALJ's proposed schedule should be modified slightly to allow an additional week for the preparation of intervenor testimony, (2) the time for comments on the proposed decision should be shortened by a week, and (3) PG&E and Edison should file updated testimony concerning their proposals on March 4. These adjustments were accepted in the procedural schedule set forth in the Scoping Memo issued by Assigned Commissioner Brown and ALJ McKenzie on March 3, 2005.[7]

B. The Parties' Testimony

In keeping with the schedule set forth in the Scoping Memo, the utilities served their updated testimony on March 4 and the intervenors served their direct testimony on March 11, 2005.

In its March 4 update, PG&E used the most up-to-date data on marginal costs and NBCs. The effect of these changes was to reduce the expected CTM from 10% to 6% in the first year. (Exhibit 1, p. 2-5.) In addition, although the proposed rate that converting customers would pay remained the same ($0.07539 / kWh), the resulting revenue allocation changed. PG&E also simplified and consolidated the forms it was proposing to use.

On the issues of system reliability and how much additional load the conversion program might produce, PG&E began by noting that due to the construction lead times for line extensions, it did "not expect a significant amount of new load to occur during summer 2005." (Exhibit 1, p. 5-1.) For 2006

---

[7] Assigned Commissioner and Administrative Law Judge's Ruling and Scoping Memo, issued March 3, 2005, pp. 4-6 (Scoping Memo).

and 2007, PG&E assumed an additional 325 Mw of new coincident peak load, the high estimate in the range AECA had calculated assuming all of the agricultural diesel pumps in PG&E's service area converted to electricity. Even with this much new load, PG&E asserted, the California Energy Commission's most recent assessment showed that under an extreme planning scenario, PG&E would still have an excess of 330 Mw in 2006 and 95 Mw in 2007, and these figures did not take into account a new contract PG&E had entered into with Duke Energy for 650 Mw of additional capacity. (*Id.* at 5-2.) Thus, PG&E concluded, there was ample electric supply available to serve the incremental electric load that the conversion program could be expected to produce. (*Id.* at 5-1.)

In its updated testimony, Edison also concluded that the likely new load did not pose any reliability concerns. Since eight weeks would be required for a customer to begin receiving power once it signed up for the conversion program, and since a Commission decision approving the program was not expected before June 30, 2005, Edison anticipated no load impacts in 2005. It also projected that a total of only about 100 customers were likely to sign up for the program by 2007, who would add about 3.4 Mw in coincident peak load. Two-thirds of this likely incremental load was located in Kern and Tulare Counties, which are served by a number of transmission circuits located north of congested Path 26. (Ex. 3, pp. 2-3.)

Significantly, Edison's March 4 update reduced its proposed average rate discount from 20% to 12.5%, a change that meant customers converting their pumps from diesel to electricity in both the PG&E and Edison service territories would be paying an initial rate of $0.07539 per kWh. With this change, Edison noted, its price floor -- including all marginal costs and NBCs -- would provide a 5.5% CTM in the first year.[8] (*Id.* at 4.) When combined with the proposed 1.5% annual increase in the rate, Edison asserted this would "help[] insure recovery of positive CTM over the term of the agreements." (*Id.* at 5.)

In the testimony it served on March 11, TURN took sharp issue with the utilities' proposal to offer converting agricultural customers a flat adder ($32,395 in PG&E's case, $29,942 in Edison's) in addition to the line extension allowances for which the customer would be eligible. According to TURN:

> "Applying a fixed line extension adder to extensions intended to convert irrigation pumps that range from 50 hp to 500 hp, will result in ratepayers paying a wide range of costs for NO_X emission reductions on a dollars per kW basis. Under Edison's proposal ratepayers would pay from $60/kW to $600/kW for NO_X reduction, while under PG&E's proposal ratepayers would pay between about $65/kW and $650/kW for NO_X reductions.
>
> "Instead of providing an 'adder' that results in such a wide range of costs for NO_X reductions, TURN suggests providing a line extension adder closer to the average costs for NO_X emission reductions estimated by the utilities. Both PG&E and Edison calculate their line extension adder based on converting an average sized engine of 150 kW. For Edison this results in an average ratepayer investment for NO_X emission reductions of $200/kW.
>
> "TURN believes it is more reasonable for ratepayers to invest this 'average' for NO_X emissions reductions than the extremely wide range of costs that would result from a single fixed line

---

[8] Edison also noted that if NBCs were excluded from the price floor, the CTM in the first year would be 20.91%. (*Id.*)

> extension adder . . . In order to prevent ratepayers from providing large subsidies for agricultural customers who are at extreme ends, . . . the line extension adder should be capped at the lower of either $200/kW or $40,000 for any individual customer." (Ex. 5, pp. 3-4.)

In addition to capping the proposed adder, TURN suggested that a cap should be imposed on the utilities' total spending for line extensions arising out of the conversion program. Noting that PG&E had estimated it would spend somewhere between $34 and $127 million on the new program, while its current spending on line extensions for agricultural customers was not more than $1.5 million, TURN said "it is not at all reasonable or prudent to increase capital spending at a level well over two magnitudes . . . greater than normal." To mitigate the potential for such "gargantuan" increases in spending, TURN recommended a cap for the conversion program of $20 million for each utility. (*Id.* at 5.)

In addition to its concerns about the proposed adder, TURN also suggested that the Commission should adopt one of three measures to ensure that the engine conversion program did not add so much additional load as to endanger system reliability. TURN recommended that the Commission should either (1) require that all new pumps installed under the program be equipped with direct load control devices controlled by the utility, or (2) require that customers signing up for the program agree to be interruptible customers, or (3) require that the conversion program retain the current on-peak charges set forth in the otherwise applicable tariffs. (*Id.* at 7-10.) In order to discourage the utilities from using the conversion program to gain a competitive advantage over municipal utilities and irrigation districts competing for the same agricultural load, TURN also proposed that if a territory serving a diesel conversion customer was taken over by a municipal utility or irrigation district in the program's first eight years, the utility's shareholders should be required to pay half of the rate discounts received by the conversion customers back to ratepayers. (*Id.* at 10-11.) TURN also argued that the Commission should declare that all emission credits arising from the program and not donated to CARB or the applicable air quality district should be considered ratepayer property. (*Id.* at 11.)

While ORA recommended that utility shareholders should pay for 25% of the rate and line extensions (since shareholders would benefit from the likely load growth), and that PG&E should reduce its rate discount to 12.5% (as Edison had done), most of ORA's testimony was devoted to the CTM issue. Arguing that the best measure of the proposed conversion was its impacts on non-participating customers (*i.e.*, all customers not signing up for the conversion program), ORA concluded that for PG&E, the first-year CTM was near the breakeven point when using the NCO method, while the CTM over the 10-year life of the program was negative. The results were better for Edison because it was proposing only a 12.5% rate discount, and also used less up-to-date marginal costs. (Ex. 4, p. 2-6 to 2-7.)

ORA also argued that the NCO method of computing CTM understated the conversion program's true costs, and that the so-called rental method was preferable. ORA explained the difference between the two methods and their impacts as follows:

> "The NCO method was developed specifically for use in revenue allocation, and the Commission's approval of this method for that application does not make it appropriate for all applications. The method was designed to address the specific problem of how to reflect hookup cost in a revenue allocation purportedly based on marginal costs when this cost is sunk and not marginal for any existing customer. In the interest of not

> excluding this cost entirely, the Commission opted for including only a small fraction of the hookup cost. The opposing method . . . is the so-called 'rental' method. It is based on a market principle where the 'rent' associated with the *entire* cost of a **new** hookup is charged to each and every customer, even to those whose hookups were installed many years ago. The two methods produce very different results for PG&E because the number of new customers constitute only 0.16% of the pool of customers in any given year. The two methods yield very similar results for [Edison] owing to its much larger agricultural customer growth rate.
>
> "Though the rental method has been rejected for use in revenue allocation, it is well suited for an analysis where all the customers are all new, such as in the [agricultural engine conversion] program." (*Id.* at 2-8 to 2-9; footnotes omitted; emphasis in original.)

After describing and emphasizing the uncertainties in the data used by PG&E and Edison, ORA recommended that the conversion program could be improved by limiting the ratepayers' exposure for line extension costs. Specifically, for pump sizes under 400 kW, ORA recommended that the line extension allowances (including the adder) be limited to what would be paid for a line extension of 1000 feet. Such a limitation, ORA argued, would eliminate double digit negative CTMs, and affect only 5% of potential program participants (according to AECA's analysis). Thus, it seemed the best solution to the problems that ORA's analysis had identified. (*Id.* at 2-11 to 2-13.)

The California Farm Bureau Federation (CFBF) also submitted testimony on March 11. Most of CFBF's testimony was devoted to the system reliability and CTM issues. On system reliability, CFBF echoed the view of other parties that little, if any, additional load was likely to result from the engine conversion program during summer 2005. With respect to future years, CFBF noted that while most of the engine conversions were likely to take place in PG&E's territory, discussions with CFBF members indicated that the program's participation rate was not likely to reach even 50% of the eligible engines. In view of this, CFBF calculated that the maximum amount of additional peak load likely to be added to PG&E's system was about 153 Mw, and for Edison, somewhere between 4 and 41 Mw. Thus, CFBF agreed that the conversion program was not likely to pose any reliability concerns during the 2005-2007 period. (Ex. 6, pp. 2-3.)

On the CTM issue, CFBF agreed with the utilities that their most recent marginal cost proposals should be used in the calculations, because owing to electric restructuring, it had been many years since the Commission had adopted any marginal costs. On the question of whether NBCs should be included when computing the price floors used to determine CTM, CFBF argued that it was proper to include NBCs only to the extent they were marginal, and would increase with additional load. In CFBF's view, most of the NBCs were historic, sunk costs, and so did not meet this test for inclusion. Overall, CFBF concluded, the conversion program would result in a positive CTM.

CFBF also argued that because of the need for a "high level of [rate] predictability" to induce agricultural customers to participate in the conversion program, critical peak pricing should not be incorporated into the engine conversion rate, even if such pricing were to be adopted for other customers in future years. CFBF also asserted that the Commission should not complicate the rate (and the related customer investment decisions) by requiring the use of devices such as variable speed motors. (*Id.* at 5-7.)

Dr. McCann also submitted revised testimony on behalf of AECA on February 24, 2004. Dr. McCann's February 24 update retained and corrected the text and tables in his January 21 testimony, and – to account for the uncertainty as to how many eligible agricultural customers might sign up for the conversion program -- added a series of sensitivity analyses purporting to show, under the Ratepayer Impact and Total Resource Cost tests, what a base case and break even cases would be for evaluating when the costs of the program would begin to shift to ratepayers. (Ex. 7, pp. 12-14.)[9]

C. The March 30, 2005 Joint Settlement

Under the schedule set forth in the Scoping Memo, the utilities' rebuttal testimony was due on March 25, 2005, and hearings were scheduled to begin on April 5. On March 15, however, PG&E served notice on all parties of a settlement conference to be held on March 23, 2005, and at the same time requested an extension of time until March 30 for serving rebuttal testimony. In a conversation with the ALJ concerning the extension request, PG&E's attorney observed that with luck, the settlement conference might obviate the need for rebuttal testimony. This turned out to be the case, and on March 30, 2005, all of

---

[9] Dr. McCann added the following cautionary note with respect to his sensitivity analyses:

> "These sensitivity analyses are not intended to reflect what may actually happen, but rather are intended to determine what conditions are required to cause the program to become a money loser. In other words, it is a risk analysis, not a revenue or rate forecast. The 'base case' just shows some assumed results which may be in the ballpark of where things could come out if all of the engines were converted – it is not a revenue forecast. The answer to the sensitivity analyses is that either the engines have to be really small . . . or the lines have to be exceptionally long compared to historic agricultural installations, particularly in the case of [Edison]. While PG&E shows the greatest risk on the RIM test, it also shows the largest potential societal benefits." (Ex. 7, pp. 14-15.)

the active parties filed, along with a motion for its adoption, the settlement agreement called the Joint Settlement that is appended to this decision as Attachment A.[10]

Although the Joint Settlement itself is fairly short, it contains extensive references to the utility testimony that was filed on November 9, 2004 and March 4, 2005, and many of its provisions are best understood with reference to the positions taken by the parties in the testimony summarized above.

On the issue of rates, the first paragraph of the Joint Settlement states that the "initial average rate" for both PG&E and Edison customers shall be "approximately 7.5 cents per kWh," *i.e.*, $0.07539/kWh. The first paragraph also states that based on a review of information furnished by the utilities concerning their ability to serve new load, the parties "are satisfied that there is adequate electric supply to serve the anticipated load." The parties also agree that "in order to encourage the new load served under the [PG&E conversion program] to use power during off-peak periods," PG&E's incentive rates will be modified to increase rates for on-peak and partial-peak usage. PG&E's tariff for the program is attached to the Joint Settlement as Appendix A, and Edison's tariff as Appendix B.

The second paragraph of the Joint Settlement is concerned mainly with changes to the proposed incentive rate. The agreement provides that the rate will increase by 1.5% annually, beginning on January 1, 2006, over the 10-year life of the conversion program. However, the agreement also provides that

[10] The settlement agreement is five pages long and contains 12 numbered paragraphs. Except where indicated otherwise, the references in this decision are to these numbered paragraphs.

"although unbundled rate components may change throughout the year, the total [conversion] rates will change only on January 1 of each year," as set forth in Chapter 2 of both PG&E's and Edison's March 4, 2005 updated testimony. Paragraph 2 of the Joint Settlement also states that the rates "are not exempt from collection of CPUC approved non-bypassable charges, including the Nuclear Decommissioning Charge, the Public Purpose Program Charge, and the DWR Bond Charge," and that this treatment is reflected in the attached tariffs. Finally, the parties agree that during the 10-year life of the engine conversion program, "it is not necessary for the Commission to revisit the contribution to margin or marginal costs of serving customers participating in the . . . Program, and no party shall advocate for such a revisitation." (Joint Settlement, ¶ 2.)

The third paragraph provides that while the agreed-upon rate and line extension incentives are appropriate for encouraging agricultural customers to convert their diesel pumping engines to electric service, "agreement to the Joint Settlement shall not be cited by any party as precedent for any purpose."

The fourth paragraph of the agreement deals with how the line extension adders should be calculated. In place of the flat adder for all customers proposed by PG&E and Edison, "the maximum 'adder' . . . shall be modified to reflect the kilowatt (kW) rating of each electric motor connected to replace a qualifying internal combustion engine," as set forth in the following table:

kW Rating of Replacement Electric Motor	Maximum Adder
up to 124 kW	$ 7,500
125 kW to 224 kW	$15,000
225 and above kW	$32,395

Paragraph 5 of the Joint Settlement provides that the conversion program will commence on the effective date of Commission approval of the settlement, will remain open for two years from this effective date, and that the incentive rates will remain in effect until December 31, 2015.

The stipulated line extension adders set forth in paragraph 4 are linked to paragraph 6 of the Joint Settlement, which provides that "the total capital investment (including both standard allowances and line extension adders) shall be limited to $27.5 million for PG&E and $9.17 million for [Edison] over the two-year enrollment period." These limits are to be enforced as follows:

> "Program participation will be granted on a first-come, first-serve basis. When either utility forecasts that it will reach its designated limit on total capital expenditures, no further adders or incentive rates shall be allowed by that utility, and the Program will be closed to any additional customers." (*Id.*, ¶6.)

Paragraph 7 provides that both utilities "shall be permitted to record costs of connecting electric services under the [engine conversion] Program to a balancing account for recovery" as set forth in Chapter 2(D) of PG&E's March 4, 2005 testimony and Chapter 2 of Edison's November 9, 2004 testimony.

Paragraph 8 is concerned with the possibility of stranded investment in the event a municipal utility or irrigation district takes over a service area that includes a customer who has signed up for the program. To deal with this possibility, the parties agree that the service extension agreements of PG&E and Edison (which are attached to the settlement as Appendices C and D, respectively) shall be revised as follows:[11]

---

[11] Paragraph 9 of the agreement provides that the billing letter, general terms and conditions and application-for-service forms included in PG&E's updated March 4

Footnote continued on next page

> "If the customer departs from the utility system within ten years from the date of the agreement to take distribution service from another provider, the customer will be required to reimburse the utility for the amount of the adder and the difference between rates paid under the [engine conversion] tariff and rates under the otherwise applicable tariff."

Paragraphs 10 and 11 of the Joint Settlement deal with a competitive issue raised by TURN, as well as the concern of TURN and ORA that all emission credits resulting from the program and not turned over to CARB or an air pollution control district should be treated as ratepayer property. On these questions, paragraph 10 states that "no more than 100 program participants will be permitted within the boundaries of the South San Joaquin Irrigation District in southern San Joaquin County," and paragraph 11 states that all "air emission reductions acquired by the utilities through the [engine conversion] Program" that are not donated to CARB or the applicable air district "shall be held for the benefit of ratepayers."

The text of the Joint Settlement closes with standard provisions found in most Commission settlement agreements; *viz.*, a statement that the settlement resolves "all disagreements" among the parties relating to these applications, that all parties agree to support the settlement, and that this support "is expressly conditioned upon CPUC approval without modification or condition that is unacceptable to any Settlement Party." (*Id.*, ¶ 12.)

---

testimony "shall be approved for use in the [engine conversion] program." The analogous documents for Edison are included within its tariff, which is attached to the settlement agreement as Appendix B.

On April 1, 2005, the ALJ informed the parties that a short hearing would be held concerning the Joint Settlement. The hearing took place on April 7, 2005, one of the days that had been set aside for hearings in the Scoping Memo. At the hearing, the parties' testimony was received into evidence, and the ALJ asked questions about the meaning of various provisions in the Joint Settlement. Relevant passages from the April 7 hearing transcript are set forth in the next section of this decision.

D. Discussion

We have decided to approve the April 30 Joint Settlement because of the reasonable balance it strikes between the competing interests in this case. On the one hand, residents of the Sacramento and San Joaquin Valleys seem likely to benefit from substantial improvements in their local air quality, while participating agricultural customers will receive a rate that is guaranteed for 10 years (apart from the 1.5% annual escalation factor), as well as an adder that supplements the line extension allowances to which they would otherwise be entitled. At the same time, ratepayers will be protected from excessive costs because (1) total capital investment in line extensions and adders for the engine conversion program will be capped at $27.5 million for PG&E and $9.16 million for Edison, (2) the graduated nature of the adders will help to ensure that ratepayers are not paying excessive amounts for the NO_X reductions that will result, and (3) any emission credits for carbon dioxide (CO_2) resulting from the conversion program will remain ratepayer property. We are also satisfied that the additional load likely to come about in the next few years from the engine conversion program does not pose any reliability concerns.

There is no dispute that the population of diesel-powered engines contributes significantly to the poor air quality in California's Central Valley. PG&E's updated testimony describes the current situation as follows:

> "The San Joaquin and Sacramento Valleys are subjected to heavy amounts of air pollutants, ranking with the Los Angeles basin as one of the most polluted regions in the nation. Air pollution in the California central valley persistently exceeds the national ambient air quality standards. According to [CARB,] agricultural sources contribute 26 percent of the smog forming emissions in the San Joaquin Valley. CARB estimates that there are more than 5,700 stationary diesel-powered pumps used for irrigation in the central valleys, which are significant contributors to agriculture's air quality impact. In part because of agriculture's air quality impact, the Sacramento and San Joaquin Valleys are currently classified as Federal Air Quality Non-Attainment areas for ozone, which could result in a reduction of federal transportation funding for California.
>
> "During the 2003 summer, CARB estimates that diesel irrigation in the central valleys emit 33 tons per day of oxides of nitrogen (NO_X), which accounts for nearly 23 percent of the total NO_X emissions from stationary fuel combustion sources in the region. In addition, CARB estimates that diesel pumps represent about 31 percent of the reactive organic gases (ROG) from stationary fuel combustion sources in the central California valleys.
>
> * * *
>
> "The region suffers from unhealthy air quality in the winter months as well, largely due to particulate matter (PM) emissions. CARB estimates that during 2003, 17 percent of PM emissions from stationary fuel combustion sources in the region were caused by diesel-powered irrigation pumps. It is estimated that PM accounts for 70 percent of the known cancer risk that is attributable to exposure to toxic air pollutants in California." (Ex. 1, pp. 1-1 to 1-3; footnotes omitted.)

It is because of these problems, and especially because of the low-level ozone created during the summer by the reaction of sunlight, NO_X and ROGs, that CARB and two regional air quality control districts have expressed their support the Joint Settlement.[12] Although the settling parties disagree as to the number of diesel engines likely to be taken out of service as a result of the conversion program, it seems clear that even if the program achieves a relatively modest level of participation, significant improvement in the Central Valley's air quality should result. It was largely for this reason that ORA decided to support the settlement, even though it concluded that CTMs over the ten-year life of the incentive conversion rate are likely to be negative.[13]

Based on the testimony of the utilities and CFBF, we are also satisfied that any additional peak load resulting from the conversion program is not likely to

[12] On March 31, 2005, the Sacramento Metropolitan Air Quality Management District and the San Joaquin Valley Air Pollution Control District both sent letters to the ALJ expressing their support for the Joint Settlement.

[13] This is clear from the following colloquy that took place between the ALJ and ORA witness Christopher Danforth at the April 7 hearing:

> "ALJ MCKENZIE: I guess my question was, since the settlement agreement contemplates that . . . the Commission should not . . . revisit during . . . the ten-year life of the agreement, marginal costs or contribution to margin, whether you were satisfied, in view of the other terms of the agreement, that there was likely to be a positive [CTM] from . . . the population of engines you were looking at over the life of the agreement, or you were really looking . . . more at the first year? . . .
>
> "MR. DANFORTH: I was taking a one-year window. I had in the back of my mind that the ten-year window probably would yield negative results, but ORA is willing to live with that in light of the air-quality benefits of the program." (April 7 Transcript, p. 40.)

pose reliability problems during the 2005-2007 timeframe. As both Edison and PG&E have pointed out, the lead times necessary to sign up for the program and to construct any necessary line extensions mean that almost no additional load is likely to result from the program during summer 2005. The estimates of how much additional load can be expected in the summers of 2006 and 2007 depend on the assumption one makes about the success, or participation, rate of the program with eligible customers. PG&E's updated testimony shows that even assuming a 100% participation rate among eligible customers in its service territory, the additional load can be handled with the surplus that the CEC expects PG&E to have. (Ex. 1, pp. 5-1 to 5-2.) If one uses the 50% participation rate assumed by CFBF (which seems to us more realistic), the available surplus is even larger. (Ex. 6, pp. 2-3.) The evidence shows that because of its smaller population of diesel engines, reliability concerns in Edison's service territory are even smaller. (*Id.*; Ex. 3, pp. 2-3.)

Although both TURN and ORA agreed that the engine conversion program would improve air quality, and that any reliability concerns could be managed, their testimony raised serious issues about the cost-effectiveness of the program as it was originally proposed. As noted in Section B, TURN was concerned that the flat line extension adders proposed by the utilities ($32,395 for PG&E customers, $29,942 for Edison's) would result in ratepayers paying widely varying amounts for NO_X reduction, and could lead to "gargantuan" increases in line extension spending for agricultural customers. ORA was concerned that the proposed rate reduction (20% for PG&E agricultural customers, 12.5% for Edison's) resulted in a negative CTM, contrary to the assertions of the utilities.

The Joint Settlement addresses all of these concerns in a straight-forward way. By tying the amount of the line extension adder to the size of the replacement electric engine, the settlement addresses TURN's concern that the size of the adder ought to be linked to the amount of NO_X reduction that the engine conversion achieves. The sliding scale of adders the parties have agreed upon ($7500, $15,000, $32,395) also has the virtue of administrative simplicity, which was not true of ORA's proposal.[14]

The Joint Settlement's provision for adders based on engine size also appears to address ORA's concern that the original utility proposals would result in double-digit negative CTMs. ORA's testimony stated that it proposed to limit the total line extension payments for engines under 400 kW because "the 1000 foot limit essentially eliminates the double-digit CTMs for all of the smaller pumps except those that are 50 kW." It appears that the more direct approach reflected in the settlement – *i.e.*, tying the amount of the adder to engine size – also serves to eliminate double-digit negative CTMs.

The limitation on total line extension capital spending for engine conversions addresses another of TURN's concerns. As noted above, TURN's testimony had expressed alarm about the potential for "gargantuan" increases in line extension spending, in view of PG&E's estimate that its spending for line extensions for agricultural customers was likely to increase from $1.5 million annually to somewhere between $34 and $127 million annually. TURN's

---

[14] As noted in the text, ORA's testimony had proposed that for pump sizes under 400 kW, total line extension allowances (including the adder) should be limited to what would normally be paid for a line extension of 1000 feet to support the same load. (Ex. 4, pp. 2-11 to 2-13.) At the April 7 hearing, ORA's Danforth stated that "in the course of [settlement] discussions we decided it would be more efficient than trying to set a distance limitation to directly make the adder proportional to the size of the [replacement electric] engine." (*Id.* at 31.)

solution to this was to cap total spending for such line extensions at $40 million. The spending limitation the parties have agreed upon in paragraph 6 of the Joint Settlement, $36.67 million, is close to that figure, and its components -- $27.5 million for PG&E, $9.16 million for Edison – reflect the fact that there are about three times as many eligible engines in PG&E's service territory as in Edison's. (April 7 Transcript, p. 36.)

Two other aspects of the Joint Settlement deal with competitive concerns raised in TURN's testimony. First, as noted above, TURN was worried about the possibility of stranded investment in the event a municipal utility or irrigation district took over, at some point during the 10-year period the discounted incentive rate was in effect, a territory serving customers who had switched from diesel-powered engines to electric ones. TURN argued that if such a takeover occurred, the utility's shareholders should be required to pay half of the rate discounts received by the conversion customers back to ratepayers. (Ex. 5, pp. 10-11.) Paragraph 8 of the Joint Settlement deals with this possibility by requiring that if a conversion customer departs from the utility's system "within ten years from the date of the [engine conversion] agreement to take distribution service from another provider, the customer will be required to reimburse the utility for the amount of the adder and the difference between rates paid under the [engine conversion] tariff and rates under the otherwise applicable tariff." In light of the whole settlement agreement, we consider this a fair resolution of the stranded investment issue that TURN has raised.

Paragraph 10 of the Joint Settlement deals with a special case of TURN's concern about competition between utilities and irrigation districts to serve load. Paragraph 10 limits to 100 the number of conversion program participants in the portion of the South San Joaquin Irrigation District located in southern San

Joaquin County. At the April 7 hearing, TURN witness Nahigian testified that the parties developed this number by determining the ratio between the geographic area of San Joaquin County and the portion of the South San Joaquin Irrigation District that lies within that county, and then applying that ratio to the number of eligible engines within the county. Using this approach and a population of 420 eligible engines county-wide, the parties determined that the limit should be 100. (April 7 Tr., pp. 37-38.) We also consider this approach reasonable.

One final issue that needs to be mentioned is the request by both PG&E and Edison that the Commission grant an exemption from Pub. Util. Code § 851,[15] pursuant to § 853(b),[16] for the transfer to CARB or local air districts of the emission reductions that will be obtained from customers as a result of the engine conversion program. (Ex. 1, pp. 1-6 to 1-7; Ex. 2, p. 10.) In their joint April 29, 2005 brief supporting the exemption request, PG&E and Edison argue in support of the exemption as follows:

> "In this case, there is no public interest served by subjecting the transfer of emission reductions to Commission review under section 851. The transfer will not affect, in any way, the

---

[15] Pub. Util. Code § 851 provides in pertinent part:

> "No public utility . . . shall sell, lease, assign, mortgage, or otherwise dispose of or encumber the whole or part of its . . . line, plant, system, or other property necessary or useful in the performance of its duties to the public . . . without having first secured from the commission an order authorizing it to do so."

[16] Pub. Util. Code § 853(b) authorizes the Commission to exempt public utilities from the requirements of §§ 851-856 if the Commission finds "that the application thereof to such public utility . . . is not necessary in the public interest.

> utilities' ability to provide service to their customers. Indeed, the utilities do not currently own the emission reductions and would only acquire them as part of this program to reduce the use of diesel engines in California. Transferring the emission reductions to the environmental agencies would accomplish the objective of permanent air quality improvements without having any impact whatsoever on the utilities' ability to serve their customers. Therefore, PG&E and [Edison] request that the Commission exempt the transfer from the requirements of section 851." (April 29 Joint Brief, p. 4.)

We agree with this analysis and will grant the requested exemption. As PG&E and Edison point out, the Commission has recently granted such requests in cases where no public interest would be served by subjecting a proposed utility transaction to Commission review. In D.04-03-020, for example, we granted Lodi Gas Storage L.L.C. (Lodi) an exemption from § 851 for the purpose of assigning its accounts receivable to secure a $5 million short-term working capital line of credit, as well as a larger revolving line of credit. After noting that without the assignment, Lodi would have to pay "300 to 500 basis points (3% to 5%) more for short-term money and be subject to tighter operating provisions and covenants from the lender," we concluded that "it is not necessary to impose § 851 regulation of such financial transactions to ensure the ongoing ability of [Lodi] to perform its public utility operations." (*Mimeo.* at 2, 5.) In this case, because PG&E and Edison will be obtaining the emission credits from customers solely as a result of the conversion program, and the assignment of these credits will bring about permanent air quality improvements without having any impact on the ability of the two utilities to serve their customers, an exemption from the requirements of § 851, pursuant to § 853(b), is appropriate.

E. Findings of Eligibility for Intervenor Compensation

On February 14, 2005, both TURN and AECA filed a Notice of Intent (NOI) to claim compensation in these proceedings pursuant to Pub. Util. Code § 1804(a). Under this provision, a party that intends to seek compensation for its participation in a proceeding must include in its NOI a showing that it is a customer or represents customers, as well as (1) a statement of the nature and extent of the customer's planned participation in the proceeding (§ 1804(a)(2)(A)(i)), and (2) an itemized estimate of the compensation the customer expects to request, given the likely duration of the proceeding when the NOI is filed (§1804(a)(2)(A)(ii)). In addition, the customer may present in its NOI a showing that participation in the proceeding would represent a significant financial hardship, but the customer may also defer that showing until it files a compensation request. (§1804(a)(2)(B).)

TURN's NOI satisfies all of these requirements, including the hardship showing. TURN's NOI notes that it intends to address issues including the cost and revenue impact of the engine conversion program on residential ratepayers, whether the proposed program makes a positive CTM, and whether the program might unduly impact system reliability. TURN's itemized estimate states that it expects to seek about $50,500 in compensation, assuming a week of hearings. Finally, TURN's NOI notes that in a ruling issued on July 27, 2004 in R.04-04-003, it was found to have met the burden of demonstrating financial hardship. Under Pub. Util. Code § 1804(b)(1), such a finding creates "a rebuttable presumption of eligibility for compensation in other commission proceedings commencing within one year of the date of that finding." Since these proceedings were commenced within one year of the July 27, 2004 ruling, the rebuttable presumption of financial hardship applies. Thus, based on its NOI, TURN is eligible for an award of intervenor compensation in this proceeding.

AECA's NOI provides a statement of the nature and extent of its planned participation in the proceeding, as well as an itemized estimate that its budget for the proceeding is expected to be $160,000. However, AECA states that it "will include its showing of significant financial hardship as part of its request for compensation in this proceeding," and not in the NOI. (AECA NOI, p. 4.)

While AECA's showing permits us to make a preliminary determination that is eligible for an award of compensation, that determination, as the ALJ held in A.02-05-004, "is conditioned upon [AECA's] successfully making a showing of significant financial hardship and . . . providing certain other information."[17] For example, after noting that AECA's membership included a significant number of water districts, and that public agencies are not considered "customers" eligible for compensation under Pub. Util. Code § 1802(b)(2), the Edison GRC NOI Ruling stated:

> "I again determine that in the event AECA files a request for compensation in this proceeding, it should include in that filing a demonstration of how it qualifies as a customer in this proceeding under § 1802(b) notwithstanding its representation of water districts. AECA should also provide in any compensation request additional information to clarify the nature and role of its association members, and explain whether and how such members affect its status as a customers under § 1802(b). Finally, AECA should include data that would enable the Commission to affirm, update, or otherwise address

[17] A.02-05-004 & I.02-06-002, Administrative Law Judge's Ruling on Notices of Intent to Claim Compensation, issued August 27, 2002, p. 2. This ruling is hereinafter referred to as the "Edison GRC NOI Ruling."

> the 61.6% compensation factor adopted for AECA in previous compensation awards." (*Id.* at 5.)

In the NOI it filed on February 14, AECA purports to address some of these concerns. It states, for example, that its members include "individual producers, processors [and] produce cooling operations," and that these members should be considered "small commercial customers" within the meaning of Pub. Util. Code §1802(b)(1)(C), even though some of them are apparently also represented by one or more of the 19 agricultural industry associations that are also AECA members. The NOI also states that AECA "will not request any compensation for its representation on behalf of water districts, which are public agencies" and thus ineligible for compensation under § 1802(b)(2). However, the NOI presents no quantification – in terms of dues paid or number of members – that would enable us to assess how significant a role water districts and agricultural industry associations play in determining AECA's affairs. In the absence of such information, we cannot now find -- as AECA has requested -- that it is an organization authorized to represent small customers within the meaning of Pub. Util. Code § 1802(b)(1)(C).

In the Edison GRC NOI Ruling, the ALJ noted that "AECA did not explicitly discuss whether it represents customer interests that would otherwise be underrepresented in this proceeding," and pointed out that "AECA assumes the risk of reduced compensation or denial of compensation to the extent that it represents interests that are, or would be, adequately represented in the absence of AECA's participation." (*Mimeo.* at 5.) In its NOI, AECA states that its showing of significant financial hardship will address these issues, as well as data bearing on whether the 61.6% compensation factor should be updated or retained.

We look forward to reviewing all of the material that AECA has represented will be in its compensation request. We also remind AECA that "a finding of significant financial hardship in no way ensures compensation." (§ 1804(b)(2).)

F. Assignment of Proceeding

Geoffrey F. Brown is the Assigned Commissioner, and A. Kirk McKenzie is the assigned ALJ in this proceeding.

G. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1, along with an ALJ Ruling shortening the time for comments pursuant to a stipulation entered into by the parties. Pursuant to this ALJ ruling, opening comments were filed on ___________, and reply comments on _______________.

Findings of Fact

1. On March 30, 2005, the active parties in these proceedings filed the Joint Settlement set forth in Attachment A, along with a motion requesting that the Commission adopt the Joint Settlement.

2. Even with a relatively low participation rate, the diesel engine conversion program described in the Joint Settlement is likely to result in a significant improvement of the air quality in the Sacramento and San Joaquin Valleys.

3. PG&E and Edison both have sufficient resources so that the additional peak load that can be expected as a result of the diesel engine conversion program set forth in the Joint Settlement will not present reliability problems during the 2005-2007 time period.

4. The provisions of the Joint Settlement represent a reasonable effort by the active parties to balance the benefits of the diesel engine conversion program as

originally proposed by the utilities against the concerns about the costs of the program, as set forth in the intervenors' testimony, especially that of ORA and TURN.

5. But for the provisions of the engine conversion program set forth in the Joint Settlement, neither PG&E nor Edison would be obtaining the emission reduction credits that they have agreed to (a) donate either to CARB or the applicable air district, or (b) hold for the benefit of their ratepayers.

Conclusions of Law

1. The initial rate of $0.07539 per kWh that will be paid by agricultural customers who agree to convert their diesel engines to electric service pursuant to the engine conversion program described in the Joint Settlement, is reasonable and should be approved.

2. The provision in the Joint Settlement that the initial rate of $0.07539 per kWh shall escalate at a rate of 1.5% per year during the 10 years these incentive rates are in effect, is reasonable and should be approved.

3. The provision in the Joint Settlement that the electric engine rates provided for therein are not exempt from non-bypassable charges approved by this Commission, including Nuclear Decommissioning Charge, the Public Purpose Program Charge and the DWR Bond Charge, is reasonable and should be approved.

4. The provisions in the Joint Settlement that (a) it is not necessary for the Commission to revisit the issues of the marginal cost of serving, or the contribution to margin paid by, customers who participate in the diesel engine conversion program, and (2) that no party to the Joint Settlement shall advocate for such a revisitation, are reasonable and should be approved.

5. The line extension adders based on the kilowatt rating of the replacement electric motor, as set forth in paragraph 4 of the Joint Settlement, are reasonable and should be approved.

6. The provisions in the Joint Settlement that (a) the diesel engine conversion program shall commence as of the effective date of the Commission's approval of the Joint Settlement, (2) the diesel engine conversion program shall remain open for a period of two years from said effective date, and (3) the incentive rates included within the diesel engine conversion program shall remain in effect through and including December 31, 2015, are reasonable and should be approved.

7. The provisions in the Joint Settlement that total capital investment (including both standard line extension allowances and adders) shall be limited to $27.5 million for PG&E and $9.17 million for Edison during the two-year enrollment period for the engine conversion program, and the provisions relating to how these limits shall be enforced, are reasonable and should be approved.

8. The provision in the Joint Settlement permitting PG&E and Edison to record in a balancing account for recovery, the costs of connecting electric service under the diesel engine conversion program, is reasonable and should be approved.

9. The provisions in the Joint Settlement requiring that the PG&E and Edison service extensions agreements be amended to require that, if a customer departs from the utility system within 10 years after signing an engine conversion agreement to take service from another provider, such customer must reimburse the utility for the amount of the adder, plus the difference between the incentive

rates paid by the customer and the otherwise applicable rates, are reasonable and should be approved.

10. The provision in the Joint Settlement stating that no more than 100 engine conversion program participants will be permitted within the boundaries of the South San Joaquin Irrigation District in southern San Joaquin County, is reasonable and should be approved.

11. The provision in the Joint Settlement stating that all emission reduction credits (including CO_2 credits) that are acquired by PG&E or Edison as a result of the engine conversion program and not donated to CARB or the applicable air district, shall be held for the benefit of ratepayers, is reasonable and should be approved.

12. Taken together, the provisions of the Joint Settlement are reasonable in light of the whole record, consistent with law, and in the public interest, and should be approved.

13. Pursuant to Pub. Util. Code § 853(b), PG&E and Edison should be granted an exemption from the requirements of Pub. Util. Code § 851 with respect to the emission reductions they will obtain solely as a result of the Joint Settlement's engine conversion program, and then donate either to CARB or the applicable air pollution control district.

14. Pursuant to Pub. Util. Code § 1804(b)(1), TURN should be found eligible for an award of intervenor compensation in this proceeding.

15. Pursuant to Pub. Util. Code §1804(b)(2), AECA should preliminarily be found eligible for an award of compensation in this proceeding. Before any compensation can be awarded, AECA must present a showing of significant financial hardship addressing the issues set forth in this decision.

O R D E R

IT IS ORDERED that:

1. The March 30, 2005 Joint Settlement appended to this decision as Attachment A is hereby approved.

2. Applicants Pacific Gas and Electric Company and Southern California Edison Company are hereby granted an exemption from the requirements of Pub. Util. Code § 851 for the sole purpose of transferring to the California Air Resources Board, the Sacramento Metropolitan Air Quality Management District, or the San Joaquin Valley Air Pollution Control District, as the case may be, emission reduction credits obtained as a result of the agricultural engine conversion program set forth in the March 30, 2005 Joint Settlement and approved in this decision.

3. The Utility Reform Network is eligible for an award of intervenor compensation for its work in this proceeding.

4. The eligibility of the Agricultural Energy Consumers Association for an award of intervenor compensation in this proceeding is contingent upon an adequate showing that without such an award, its participation would represent a significant financial hardship, as set forth in this decision.

5. This proceeding remains open for the purpose of considering requests for awards of intervenor compensation in this proceeding.

This order is effective today.

Dated ____________________________, at San Francisco, California.

ATTACHMENT A