STATE OF CALIFORNIA

PETE WILSON, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

ORIGINAL

December 28, 1998

TO: PARTIES OF RECORD IN APPLICATION 96-08-001 ET AL.

Decision 98-12-067 was signed on December 17, 1998 with a dissent from Commissioner Conlon and a concurrence from Commissioner Knight. However, the dissent and concurrence are not available at the time of mailing the enclosed decision. They will be mailed at a later date.

Lynn T. Carew

Lynn T. Carew, Chief
Administrative Law Judge

LTC:vdl

Enclosure

35308

COM/HMD,RB1/mlc **MAILED 12/28/98**

Decision 98-12-067 December 17, 1998

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of Valuation and Categorization of Non-Nuclear Generation-Related Sunk Costs Eligible for Recovery in the Competition Transition Charge.	Application 96-08-001 (Filed August 1, 1996)
Application of San Diego Gas & Electric Company to Identify and Value the Sunk Costs of its Non-Nuclear Generation Assets.	Application 96-08-006 (Filed August 1, 1996)
Application of Southern California Edison Company to Identify and Value the Sunk Costs of its Non-Nuclear Generation Assets, in Compliance with Ordering Paragraph No. 25 of D.95-12-063 (as modified by D.96-01-009 and D.96-03-022).	Application 96-08-007 (Filed August 1, 1996)
Application of Pacific Gas and Electric Company To Establish the Competition Transition Charge.	Application 96-08-070 (Filed August 30, 1996)
In the Matter of the Application of Southern California Edison Company to estimate its Transition Costs as of January 1, 1998 in Compliance with Ordering Paragraph 26 of D.95-12-063 (as modified by D.96-01-009 and D.96-03-022), and related changes.	Application 96-08-071 (Filed August 30, 1996)
Application of San Diego Gas & Electric Company to Estimate Transition Costs and to Establish a Transition Cost Balancing Account.	Application 96-08-072 (Filed August 30, 1996)

(See Decision 97-11-074 for list of appearances.)

Additional Appearances

Jack F. Fallin, for Pacific Gas and Electric Company, applicant.
Michael C. Burke, for New Energy Ventures, L.L.C.; Fritz Ortlieb, for City of San Diego Metro Wastewater Dept.; and Wayne Raffesberger, Attorney at Law, for Coast Intelligen, Inc.; interested parties.

FINAL OPINION
PUBLIC UTILITIES CODE SECTION 369 AND APPLICABILITY OF COMPETITION TRANSITION CHARGE TO NEW LOAD

Summary

In this decision, we address the issue of how the competition transition charge (CTC) is applied to new customer load where that load is being met through a direct transaction and the transaction does not otherwise require the use of transmission or distribution facilities owned by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E). We considered issues related to incremental load and § 369[1] in Decision (D.) 97-12-039.

After considering testimony, written responses to questions posed in rulings, legal briefs, and oral argument, we weigh the competing policy goals expressed by the Legislature in Assembly Bill (AB) 1890 (Stats. 1996, Ch. 854). We find that new customer load served by a direct transaction that does not require use of the utilities' transmission and distribution systems may be

connected for standby service and still be exempt from CTC collection related to new load served by the direct transaction. If standby service is used, i.e., delivered over the utilities' transmission or distribution facilities, CTC applies to the standby power consumed. This decision defines a physical test to determine whether a direct transaction requires use of the utilities' transmission and distribution systems.

Background and Summary of Parties' Positions

At the Commission Meeting on February 19, 1998, the Commission voted to withdraw Items H-5 and H-5a on that agenda and to set aside submission of these proceedings for the limited purpose of holding hearings on factual assertions related to Public Utilities Code § 369 and the application of CTC to new and incremental load served by a direct transaction when that load is also served by standby service.

These issues were first considered in workshops convened by the Energy Division in August, 1997. The Energy Division submitted its report on September 16, 1997, which was the subject of comments and reply comments. These issues were addressed in the proposed decision eventually leading to D.97-12-039, but the resolution of issues related to application of CTC to new load when that load is also served by standby service was removed from the final decision. On December 4, 1997, Commissioner Conlon issued a ruling propounding various questions related to this issue, and issued a draft decision on these issues.[2] Commissioner Knight issued an alternate on February 6, 1998

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[1] All statutory references are to the Public Utilities Code.

[2] In response to the Assigned Commissioner's Ruling issued on December 4, PG&E, Edison, Enron, Cogeneration Association of California and Energy Producers and Users Coalition (CAC/EPUC), City of San Diego's Metropolitan Wastewater Department (City of San Diego), Independent Energy Producers (IEP), California Department of General Services (DGS), Electric

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and parties provided comments on February 13, 1998.[3] In addition to the workshops and comments, several parties have filed ex parte notices. Certain factual assertions have been made in ex parte communications, which we determined should be addressed and tested in evidentiary hearings.

The scope of the hearings was limited to the following issues:[4]

1. How is the provision of standby service metered and billed? Is the connection with the utility-provided standby service at the customer side of the meter or at the non-utility generator side of the meter, or both? How would the new load be measured and billed for purposes of the CTC? When the generator utilizes services provided by a utility, who is responsible for payment of any applicable CTC? Could a generator serving the new load derive its source of power from the utility, and if so, how would that scenario impact the applicability and payment of the CTC? When the customer takes standby service from the utility, is the customer or the non-utility generator responsible for paying the CTC? Does the Commission have jurisdiction over direct transactions that do not use the utilities' transmission and distribution facilities?

2. What is the flow of electrons in terms of provision of standby service and the new customer load provided by non-utility generators? What is the flow

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Clearinghouse, Inc. (ECI), and NutraSweet Kelco Company (NutraSweet) filed comments. NutraSweet Kelco filed a motion on December 10 seeking authorization to participate in these proceedings for the limited purpose of filing comments on this issue. We grant this motion. City of San Diego and CAC/EPUC filed motions on December 11 requesting permission to file their comments one day late. These motions are also granted.

[3] City of San Diego, PG&E, and IEP filed comments on the alternate.

[4] In response to the administrative law judge's (ALJ) ruling, issued on March 16, PG&E, Edison, CAC/EPUC, City and County of San Francisco (CCSF), and City of San Diego filed legal briefs on statutory interpretation of § 369. PG&E, Edison, CAC/EPUC, City of San Diego, and New Energy Ventures (NEV) served testimony addressing the factual issues.

of dollars that accompany the provision of service to new customer load and the provision of stand-by service?

3. Does the non-utility generator physically require the utility's transmission and distribution system in order to allow the generator to start up or continue operating in order to serve the new or incremental load? What is the difference between induction generators and synchronous generators and how does each depend on the utility's transmission and distribution system, if at all? How does the provision of stand-by service interact with provision of reactive power and the Independent System Operator's (ISO) role in operating the transmission system?

4. Are such transactions occurring at this time? Is the CTC being applied to these transactions? If so, how is it measured?

5. Are the direct transactions that occur through private wires only over-the-fence transactions? What are the possible types of these direct transactions that do not use or traverse the utilities' transmission and distribution facilities?

6. How might the analysis of whether CTC is applicable change if a generator engages in a direct transaction that traverses or uses the utilities' transmission and distribution facilities, but also engages in direct transactions that do not use the utilities' systems? Is it presumed that the generator relies upon the utilties' transmission and distribution facilities for both transactions?

At the tariff workshops convened by the Energy Division in August 1997, Edison and CAC/EPUC disputed the interpretation of § 369, which states, in relevant part:

> "The commission shall establish an effective mechanism that ensures recovery of transition costs referred to in Sections 367, 368, 375, and 376, and subject to the conditions in Sections 371 to 374, inclusive, from all existing and future consumers in the service territory in which the utility provided electricity services as of December 20,

> 1995; provided, that the costs shall not be recoverable for new customer load or incremental load of an existing customer where the load is being met through a direct transaction and the transaction does not otherwise require the use of transmission or distribution facilities owned by the utility. However, the obligation to pay the competition transition charges cannot be avoided by the formation of a local publicly owned electrical corporation on or after December 20, 1995, or by annexation of any portion of an electrical corporation's service area by an existing local publicly owned electric utility."

The dispute centers on those customers whose new load is served through direct transactions, but who also rely on the incumbent utility for standby service. CAC/EPUC agree that the customer would pay the CTC, which is the mechanism for the collection of transition costs mentioned in § 369, based on the amount of standby energy used, but argue that the CTC should not apply to new or incremental load.

The City of San Diego, IEP, Enron, DGS, ECI, NutraSweet, CCSF, and NEV concur with CAC/EPUC's interpretation. The essence of this argument is that the load served by the direct transaction does not "otherwise requires the use of transmission and distribution facilities owned by the utility," and therefore would not be subject to CTC. Even if standby service is contracted for with the utilities, these parties argue that this is a separate transaction, not the direct transaction referred to § 369. Enron argues that the statutory language is straightforward and refers to the physical facilities required to effect the direct access transaction itself, i.e., if the utility's transmission or distribution facilities are not required to effect the direct access transaction, then there is no CTC liability.

CAC/EPUC assume that because the utilities will be the only providers of standby services in the near future, Edison and PG&E's interpretation would effectively eliminate this exemption. City of San Diego and DGS contend that the Commission must recognize that the standby tariff includes a demand charge associated with reserving the standby service and that an additional CTC component will be activated only upon delivery of standby energy, since under the rate freeze described in § 368(a), the frozen standby energy charge also includes an imputed or residual CTC component. These parties argue that it is inequitable to impose the full CTC obligation on new customers for their full load, because that load does not use utility facilities - it is only when standby service is used that the additional CTC should apply.

PG&E and Edison assert that such an interpretation violates the Legislature's intent to exempt new or incremental load from the CTC only when the utility's transmission or distribution facilities, including interconnection for standby service, are not used at all. Edison describes two examples that would satisfy this requirement: 1) a customer disconnects from the incumbent utility and connects to a different utility by means of a separate transmission or distribution line; and 2) a customer disconnects from the utility, a new generator serves the customer's new load, and a different utility provides standby service.

Edison contends that a customer who engages in a direct transaction to acquire generation for its new or incremental load will *not* necessarily rely on the Utility Distribution Company (UDC) for standby service. PG&E agrees with Edison and argues that the language of § 369 is unambiguous, with no exception for partial use of the utility's facilities. In addition, Edison states that if a direct access customer's source of power fails, it will be subject to the ISO's imbalance energy charges. Edison explains that new or incremental load served through UDC's system would therefore not be distinguishable from unscheduled standby load for purposes of CTC responsibility. PG&E and Edison thus maintain there is no basis to characterize standby and regular service as separate transactions, as several other parties argue.

Factual Issues

Parties explain that there are only a few types of private-wire transactions that could be impacted by our findings today. These direct transaction sales could occur through private wires to customers 1) on the same parcel of property as the generator (on-site generation), 2) on property immediately adjacent to the generator (over-the-fence sales), or 3) on property some distance away. PG&E and Edison discuss the implications of § 218, which places certain limits on the extent to which such private wire-transactions can occur without creating an "electrical corporation" that would be regulated under the Public Utilities Code. Edison explains that it does not provide standby service where the direct transaction is other than an on-site or an over-the-fence arrangement permitted under § 218, but states that it might be possible for a generator that does not fit within the class of generators described in § 218 to sell power through a direct transaction. These transactions would not fit within the category of over-the-fence transactions, but would also not be subject to standby service requirements.

Physics of electron flow

Mechanical energy is derived from a variety of fuel or energy sources and is then converted into electrical energy through a generator. Generators may be categorized as either synchronous or induction. Synchronous generators are driven by a constant source of mechanical energy. A synchronous generator system provides its own generator excitation and can generate power without being connected to the utility grid. Induction generators utilize time-varying mechanical energy and require generator excitation from the utility's transmission system and generally cannot generate power without a separate source of generator excitation (i.e., without the utility grid to provide the greater magnetism).

PG&E contends that whether generation "traverses" the grid or makes only standby use of the grid to support its output, sales transactions carried out by that generation must, by definition, make use of the grid, and therefore would not qualify for an exemption under § 369. In all scenarios with a standby connection, the non-utility generation (NUG) interconnection uses the utility system for frequency support; i.e., according to PG&E's interpretation, the utility facilities are used for standby as insurance against supply interruptions. Both PG&E and Edison assert that this assurance exists throughout the standby relationship, without regard to electron flows at any given time, and constitutes use of the utilities' facilities as the secondary power source.

Edison contends that direct transactions that rely on the utility for standby service transfer the risk of payment for their imbalance energy to the utility. Under the new market structure, scheduling coordinators submit a balanced generation and load schedule to the ISO. The scheduling coordinator must pay an imbalance energy charge to the ISO if either side of the equation is out of balance. Edison contends that if an NUG experiences an unscheduled outage and relies on the utility for back-up power, the load served by the utility will increase because the utility is providing back-up energy to the customer. The utility may therefore pay an imbalance energy charge which would not occur but for the provision of standby service.

NEV and CAC/EPUC contend that it is not useful to track the electron flow when determining whether a direct transaction does or does not otherwise require the use of the utility transmission or distribution facilities. Rather, CAC/EPUC assert that the pivotal issue is whether the generation supplying the direct transaction has a contractual path over non-utility facilities to supply the load. CAC/EPUC explain that electric utilities do not typically track electron flows for individual power purchase transactions, but rather rely on contractual transmission rights to govern power delivery in lieu of the physical flow of electrons. Thus, regardless of the actual flow of electrons, the power is "assumed" to flow over the path the transacting parties have agreed upon, and transactions over an interconnected system that is operated in parallel are governed by metered quantities, rather than instantaneous electron flows.

CAC/EPUC explains that California loads and generation resources are operated in parallel with the Western Systems Coordination Council (WSCC) interconnected grid. All interconnected generators and loads are synchronized with one another and operate at a frequency of approximately 60 hertz (or cycles per second). CAC/EPUC also explains that the utilities are subject to the Public Utility Regulatory Policies Act (PURPA), which applies to certain kinds of small private power producers and cogenerators identified as Qualifying Facilities (QFs).[5] Sections 292.303(c) and (e) of the regulations implementing PURPA (18 CFR § 292.101 et seq.) require utilities to interconnect and operate in parallel with the QFs.

Standby Service

PG&E's provisions for metering and billing standby service are set forth under Electric Rate Schedule S - Standby Service. Energy deliveries from the grid to the customer are metered and billed on a time-of-use basis, as is reactive power demand and energy. Demand values are recorded and compared to contract reservation capacity to see if adjustments are necessary. Edison's

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[5] QFs are non-utility power producers or cogenerators that meet the guidelines established by the Federal Regulatory Energy Commission (FERC). PURPA defines these guidelines which

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Schedule S applies only to situations delineated in § 372. To take service on Schedule S, the customer is required to concurrently take service on a "regular service" rate schedule. Edison's Schedule S has never been separable from the customer's otherwise applicable service rate schedule; i.e., Schedule S is not applied on a stand-alone basis. Both PG&E and Edison contend that if the generator is using the utility's facilities for standby service, every power sale transaction carried out by that generator will automatically make use of the utility's transmission and distribution facilities, which would therefore be subject to CTC.

CAC/EPUC contend that the pricing of standby service is not a function of the instantaneous flow of electrons, but reflects the contractual path concept. While the laws of physics govern the actual electron flow for any transaction at any given point in time, the assumed power supply path may not always coincide with this actual path. In sum, CAC/EPUC contend that it is the commercial transaction rather than the physics that should govern the applicability of CTC to the load served by standby service.

City of San Diego explains that it is required to have two distinct power sources by federal Environmental Protection Agency (EPA) requirements. City of San Diego explains that its 3 non-utility biogas-fired generation plants will provide electricity via direct transactions to meet new or incremental load at metropolitan wastewater facilities. City of San Diego plans synchronous generators, which do not require the use of SDG&E's transmission and distribution system to operate. City of San Diego may isolate these plants

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identify certain operating, efficiency, and fuel-use standards that must be met by the QFs in order to qualify to supply capacity and energy to electric utilities.

completely from the grid in order to avoid paying CTC on load that is served by direct transactions but does not require the utility's delivery system to do so.

Metering and Billing

In most situations, the new or incremental load served through the direct transaction will be metered. Edison recommends that if the Commission decides that CTC applies, third-party providers could be required to provide metered consumption data to the utility for the purpose of calculating CTC. Indeed, Edison believes that this requirement is in effect because we have approved Preliminary Statement Part W, which requires the Meter Data Management Agents to make metered load available for the purpose of calculating all utility charges, including CTC for departing load.

CAC/EPUC explain that proper metering and billing of standby service can be obtained by strategic location of meters so that the commercial transaction can be properly measured. The transactions can be directly metered or a calculation can be made. NEV assumes that customers taking service through private wires would be direct access customers who would be subject to the metering requirements established by the Commission. NEV states that interval metering would be required and would provide the technology to determine the times and amounts of grid-purchased energy versus self-generated power.

PG&E believes that this Commission has jurisdiction to resolve any CTC-related issues involving existing or future customers and that the Commission has jurisdiction over all utility standby service. Edison recommends that we have the jurisdiction to require that third-party metered information be made available to the utility for the purpose of calculating CTC. Edison contends that if such data is not made available, the utility should be able to refuse to supply standby service. City of San Diego and NEV contend that this

Commission has no jurisdiction over electricity transactions that do not involve the facilities of an investor-owned utility, although the Commission must have jurisdiction over safety issues relative to connection to the electrical grid (for example, SDG&E Rule 21).

Edison explains that the CTC reflected in the standby demand charges represents a small fraction of the CTC that would have been paid had the customer not been engaged in the direct transaction. Most transition costs are recovered through energy and time-related demand charges, which do not apply when no energy is delivered through Edison's transmission and distribution system, except when the alternate source of generation is not operating. Edison contends that exempting direct transactions in which the generator or the customer continues to rely on the utility grid for standby service from CTC, would cause significant cost shifting.[6]

Parties' Perspectives on Statutory Interpretation

Both PG&E and Edison have supplied us with various documents that each has classified as "legislative history" and "extra-legislative history." For example, Edison has provided the various versions of AB 1890, as introduced on February 24, 1995, as amended on April 25, 1995, June 19, 1995, July 11, July 19, April 8, 1996, and June 19, 1996, along with the various conference committee versions and as chaptered. Edison has also provided "related" AB 1890 documents, including the September 18, 1995 Memorandum of Understanding (MOU) recommendations, PG&E's rate restructuring settlement (RRS), and various presentations to committees and coalition recommendations. In

[6] Based on load growth in 1997 for medium and large commercial and industrial customers, Edison predicts a shift of between $8.5 million and $85 million in transition cost liability from large to small customers.

addition, all parties urge us to rely on the plain meaning of this section, giving credence to each and every word used and harmonized with the statute as a whole.

As stated above, PG&E and Edison believe that § 369 provides a narrow exemption only for customers that are completely isolated, or "islanded", from the utility's transmission and distribution system. These utilities contend that unless we can conclude as a matter of law that there is no use of the utility's transmission and distribution system by the NUG, we cannot conclude that the direct transaction should be exempt from CTC under § 369. PG&E and Edison contend that there can be no separation of the load served directly by the non-utility generator and the standby service provided by the transmission and distribution facilities owned by the incumbent utility, and thus, if the transaction otherwise requires any use of the utility's system, by either the supplier or the customer, the CTC applies. PG&E also argues that it does not make sense to consider the direct transaction a contract, as it is defined in § 331(c). If an entity gains any benefit from use of utility facilities - for any purpose - then there should not be an exemption for CTC purposes.

On the other hand, parties who are aligned with CAC/EPUC contend that § 369 provides an exemption for new or incremental load served through a direct transaction over private wires whether or not the load remains interconnected with the utility grid for standby service (i.e., the direct transaction itself does not otherwise require the use of transmission and distribution facilities owned by the utility).

City of San Diego interprets the plain language of the statute to state that any direct transactions that do not require the use of the utilities' transmission and distribution facilities are not subject to CTC. City of San Diego asserts that the definition of "direct transaction" in § 331(c) is central to this discussion and that the legislature's intent was to foreclose an exemption where the direct transaction contract was, in fact, dependent on the utilities' transmission and distribution facilities for purposes of delivery of generation. City of San Diego believes that the word "otherwise" is used in the statute only to distinguish between the private transaction that is using the utility's transmission and distribution delivery systems. Use of the standby connection does not meet this test. City of San Diego also contends that the narrow exemptions carved out in § 372 for cogeneration transactions do not conflict with the exemptions described in § 369.

Coast Intelligen, Inc. (Coast) presented oral argument that focused on exempting microcogeneration projects from CTC. Coast's product is limited to very small cogeneration projects, approximately 60 kilowatts in size, which operate in conjunction with the utility systems. Microcogeneration is addressed in §§ 372(e), 380, and 383(c)(1). Section 372(e) allows utilities to apply to this Commission for a financing order to finance transition costs to be recovered from customers using microcogeneration applications. Section 380 waives the otherwise applicable standby charges for eligible customers using microgeneration facilities. Section 383(c)(1) requires the California Energy Commission (CEC) to issue a report to the legislature by March 31, 1997, which considers, among other things, the need for mechanisms to ensure that microcogenerators remain competitive in the electric services market.[7]

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[7] The CEC's report, dated March 1997, points out that many microcogeneration applications have been considered to be demand-side management applications and as such, would be eligible for CTC exemptions under the definition of a general change in usage in § 371. The CEC's report determines that "lower electricity rates, changes in rate structure, and imposition

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Coast believes that these provisions are inadequate to address its concerns because standby charges are very small compared to potential CTC charges. According to Coast, the intent of language leading up to § 380 was to create a waiver of standby charges by Edison, which would be the rough equivalent of the CTC costs to a microcogenerator customer. (RT: Vol. 27, p. 3353, lines 13-16.) Coast urges a common sense interpretation of § 369 that ensures that CTC will not be applied to load served by direct transactions, simply because the generator is required to be connected to the utility for standby service.

CAC/EPUC remind us of the rules of statutory construction: we must harmonize the statute; we cannot omit words or insert words that are not there; and we must give all the terms some meaning. CAC/EPUC assert that § 369 was designed to accommodate concerns raised by the Western States Petroleum Association (WSPA) that earlier versions of AB 1890 applied CTC too broadly. CAC/EPUC maintain that the legislative history cited by PG&E and Edison has been superseded by actual language contained in AB 1890.

CAC/EPUC contend that the idea of numerous contracts for various services is expressly contemplated and accommodated by this section. Finally, CAC/EPUC explain that there is no conflict between § 369 and § 372; that § 369 applies to load served, while § 372 discusses exemptions from CTC for various kinds of generation and increases in capacity of that generation.

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of the CTC imply a need for mechanisms to ensure that microcogeneration remains competitive." The report found further that imposition of a CTC may increase the payback period for many microcogeneration projects to beyond 10 years and that if an exemption were allowed, the impact on CTC revenue would be approximately 0.004% of total expected CTC revenues over the transition period. (Policy Report on AB 1890 Renewables Funding, March 1997, p. 52.)

NEV and IEP also presented oral argument. NEV contends separate contracts for backup or standby service are expressly contemplated by the statute. Payment of CTC must be linked to the actual delivery of services by the utility. NEV believes this interpretation is more consistent with thinking of AB 1890 in terms of economic development. NEV maintains that the utilities should be allowed to collect authorized stranded costs through CTC only for services actually provided. NEV fears that competition would be stifled if the Commission allowed collection of CTC on transactions in which the UDC plays no role. IEP agrees that it is essential that the transactions be construed as two separate transactions.

Statutory Construction and Legislative History

PG&E and Edison have included papers in their briefs which they believe document the development of language and legislative intent . Edison explains that PG&E, Edison, SDG&E, IEP, California Manufacturers Association, California Large Energy Consumers Association, CAC, EPUC, and various other parties joined together during the legislative process to form groups known variously as RRS Partners, MOU and Friends, and the Coalition. These parties provided a number of draft proposals regarding electric restructuring to the Conference Committee. Interestingly, many of the parties who participated in the MOU, the RRS, and the various Coalitions now dispute the proper interpretation of § 369. We are not surprised. While the parties may have agreed on the words used to reflect their position, substantively, they were no closer to consensus on the meaning behind the words than they are now in the current debate.

The language of the statute itself is controlling. The language in the MOU cannot indicate the intent of the Legislature with regard to § 369; it merely indicates the intent of certain parties. As we have stated in other decisions, it is this Commission's duty to implement the statute according to the plain meaning of the words and to look to the legislative history only where there is ambiguity. We have reiterated these principles recently in D.97-06-060 and it is worth considering them now:

> "When construing the purpose and intent of a statute, the California Supreme Court has clearly stated that it is of little assistance to consider the motives or understandings of single individuals, because such views may not reflect the views of other Legislators who voted for the bill. (Freedom Newspapers, Inc. v. Orange County Employees Retirement System Board (1993) 6 Cal.4th 821, 831.) This admonition is particularly apt in this instance, where lobbyists and private proponents of legislation are relying upon their own views and intentions in arguing for a particular interpretation of AB 1890." (D.97-06-060, mimeo. p. 32, quoting D.97-02-014.)

Several rules of statutory construction guide us in making our decision today. The California Supreme Court recently summarized those rules:

> "'[I]n construing a statute, a court [must] ascertain the intent of the Legislature so as to effectuate the purpose of the law.' (People v. Jenkins (1995) 10 Cal.4th 234, 246, [40 Cal.Rptr.2d 903, 893 P.2d 1224].) In determining that intent, we first examine the words of the respective statutes: 'If there is no ambiguity in the language of the statute, "then the Legislature is presumed to have meant what it said, and the plain meaning of the statute governs." [Citation.] "Where the statute is clear, courts will not 'interpret away clear language in favor of an ambiguity that does not exist.' [Citation.]"' (Lennane v. Franchise Tax Bd. (1994) 9 Cal.4th 263, 268 [36 Cal.Rptr.2d 563, 885 P.2d 976].) If, however, the terms of a statute provide no definitive answer, then courts may resort to extrinsic sources, including the ostensible

> objects to be achieved and the legislative history. (See Granberry v. Islay Investments (1995) 9 Cal.4th 738, 744 [38 Cal.Rptr.2d 650, 889 P.2d 970].) 'We must select the construction that comports most closely with the apparent intent of the Legislature, with a view to promoting rather than defeating the general purpose of the statute, and avoid an interpretation that would lead to absurd consequences.' (People v. Jenkins, *supra*, 10 Cal.4th at p. 246.)" (People v. Coronado (1995) 12 Cal.4th 145, 151.)

It is also well settled that we must turn first to the language of the statute which must be read such that every word is given its usual import and significance. (Dyna-Med, Inc. v. Fair Employment & Housing Commission, (1987) 43 Cal.3d 1379, 1386-1387, 241 Cal.Rptr. 67, 70.) We must not confine our interpretation to a single section in isolation; rather, each part or section of the statute must be read so that the meaning of the statute as a whole is harmonious. (See, e.g., Wells v. Marina City Properties (1981) 29 Cal.3d 781, 176 Cal. Rptr. 104; Knox v. AC&S, Inc. (S.D. Ind. 1988) 690 F.Supp 752.) There is a presumption that words used twice or more in the same act will have the same meaning. (ICC Industries, Inc. v. United States (Fed. Cir. 1987) 812 F2d 694, 700. In addition, the general understanding is that terms that are defined in the statute are used in that sense when those same terms appear in other sections of the act. (Department of Revenue of Oregon v. ACF Industries, Inc. (1994) 510 U.S. 332, 342; see National Wildlife Federation v. Gorsuch (D.C. Cir. 1982) 693 F2d 156 .)

Discussion

In this decision, we consider how § 369 applies in three possible scenarios. First, we assume that an NUG serves new customer load and delivers that energy via the incumbent utility's transmission and distribution systems. In this case, all parties agree that the CTC applies and there is no exemption provided by § 369.

At the other end of the continuum, if an NUG serves new customer load and that new load is not in any way served by the utility's transmission and distribution system, the CTC does not apply to this new customer load. These straightforward scenarios become more complicated when we consider how the CTC applies when the NUG provides energy directly to a new customer (i.e., does not use the utility's transmission and distribution facilities to deliver energy), but that customer is connected to the utility for purposes of standby service. In this case, all parties again agree that to the extent standby energy is used, the CTC associated with that energy will apply.

The remaining question is whether the CTC will also apply to the energy provided directly by the NUG. There are competing policy principles to consider in our analysis of how to apply the CTC exemption for new load served by direct transactions where that transaction does not otherwise require the use of the utility's distribution or transmission facilities. On the one hand, we wish to uphold the Legislature's intention that "all existing and future consumers" pay the CTC. (§§ 369, 370.) This reflects our stated policy, as articulated in D.97-06-060, that to the extent possible, transition cost responsibility should be subject to as few exemptions as possible. (D.97-06-060, mimeo. at p. 60.) On the other hand, we wish to fully uphold the Legislature's intention to encourage competition (§ 330(l)(2)) and to encourage the development of the cogeneration industry (§ 372). Our policies should promote efficient use and development of California's electricity infrastructure and not encourage inefficient islanding of customer load.

The crux of this dispute is whether connection to the utilities' system for standby service constitutes use of the utilities' transmission and distribution systems in terms of the direct transaction contemplated by statute or whether this use is a separate transaction that may be distinguished for the purpose of CTC applicability. On balance, we find that interconnection with the utilities' systems for purposes of standby service does not imply the use of the utilities' facilities for purposes of the direct transaction, unless and until that standby service is actually delivered. When new customer load is met through a direct transaction and that load is also delivered to the customer through the utilities' delivery systems, i.e., by means of the utilities' transmission or distribution systems, the CTC applies. If the direct transaction cannot begin or be implemented on an ongoing basis without connection to the utilities' system, e.g., the utilities' system is required for start-up power, the CTC applies. However, if the direct transaction serving the new load can begin and be implemented on an ongoing basis without being connected to the utilities' systems, the CTC does not apply. We establish a physical test to determine whether startup and implementation of the direct transaction requires the utilities' facilities.

We make this determination after reviewing AB 1890 as a whole. The definition of "direct transaction" in § 331(c) and applied in § 369 is pivotal to our findings. Consistent with the rules of statutory interpretation, we see no reason the legislature would have used the same term defined in § 331(c) if that term were to be defined differently in other sections of the statute. We agree, as do all parties participating in these issues, that the load may well be interconnected to the utility for purposes of standby service and if that standby power is delivered, CTC applies to the standby load. In addition, all parties agree that § 369 was intended to benefit self-sufficient self-generation transactions. We concur.

The Legislature directed the Commission to establish an effective mechanism to ensure recovery of transition costs in § 369. The obligation to pay transition costs is also provided for in §§ 370 and 371. Furthermore, in addition to the exemptions in § 369, the Legislature mandated certain specific exceptions to the application of the CTC in §§ 372 and 374. Finally, Governor Wilson signed Senate Bill (SB) 90 into law on October 12, 1997 (Stats. 1997, Ch. 905). In order to fully understand the intent of § 369, we must consider its provisions in light of these relevant sections.

We considered certain elements of § 369 in D.97-06-060, in which we explained that CTC applies to all existing and future consumers, consistent with the law, and that there are three general categories of customers: 1) continuing utility full service customers; 2) customers who continue utility delivery services, but obtain all or part of their energy from a provider other than the incumbent utility (direct access customers); and 3) customers who do not rely on the utility for delivery services and obtain all or part of their energy from a provider other than the incumbent utility (departing load customers). Section 370 has been addressed, for example, in D.97-05-040, D.97-11-074, and D.97-10-087.

We also consider the provisions of § 372, which lends insight to our discussion of § 369. Section 372 is complicated and provides for several very precise exemptions to CTC collection for load served by nonmobile self-cogeneration or cogeneration facilities. Sections 330(v)(1) and 367(e)(1) provide for a firewall related to transition cost recovery. Shortfalls in transition cost recovery caused by exemptions can be recovered only from the members of either 1) the combined class of residential and small commercial customers or 2) all other customers, depending on which of these two broad classes the exemption covers. We do not believe the firewall provisions exclude the exemptions addressed in § 369. Further, we do not agree that allowing the stated exemption in § 369 will render § 372 superfluous. At any rate, the § 369 exemption that has parties so concerned is for the private wire transactions occurring prior to June 30, 2000. It is worth noting that after June 30, 2000, all over-the-fence transactions that utilize cogeneration and self-cogeneration facilities are exempt from CTC. Generally, § 372 provides CTC exemptions for existing cogeneration loads or additional capacity from such projects. Section 372 thus allows for limited sales of power from cogeneration facilities to existing load or to a utility's departing customer load without imposition of CTC. The law specifically provides for exemptions related to cogeneration and also anticipates a means by which additional exemptions may be obtained. Additionally, § 380 provides for waiver of the standby charge for microgenerators meeting the specific provisions of that section.

Section 331(c) defines direct transaction as "a contract between any one or more electric generators, marketers, or brokers of electric power and one or more retail customers providing for the purchase and sale of electric power or any ancillary services." By substituting this definition for the term "direct transaction" in § 369, the meaning is unmistakable:

> "... provided, that the costs shall not be recoverable for new customer load or incremental load of an existing customer where the load is being met through a [contract between any one or more electric generators, marketers, or brokers of electric power and one or more retail customers providing for the purchase and sale of electric power or any ancillary services] and the [contract] does not otherwise require the use of transmission and distribution facilities owned by the utility. ..."

In comments on the ALJ's PD, Edison argues that this interpretation "would invite sham transactions, in which ... contracting parties are left free to stipulate to the "contractual" path, without regard to the actual flow of power in a T&D system, and without oversight by this Commission." (Summary, p. 2, September 24, 1998, Southern California Edison Company Comments on

Proposed Decision of ALJ Minkin.) While it is certainly possible that a party might put forward the position that Edison fears, the physical test we establish below ensures that the physical realities of the transaction determine the CTC applicability, not solely the contract terms.

We are convinced that there was strong support in AB 1890 both for competitive options and for the development of cogeneration and microgeneration. Although the Legislature intended for the CTC to apply as widely as possible, in fact, to "all existing and future consumers," the Legislature also intended that an exemption for direct transactions that do not otherwise use the utilities' transmission or distribution systems not be eviscerated by charging CTC on all load simply because of a connection for standby power that may or may not be used.

Physical Test of Whether Utilities' Systems are Used to Implement the Direct Transaction

We adopt a simple physical test to determine whether or not utilities' systems are used to implement a direct transaction as follows: if the direct transaction can be consummated, that is, start and operate on an ongoing basis, without the parties to the direct transaction, i.e., the generator, customer (new or incremental load), or third-party transmission/distribution provider, being connected to the utilities' systems, then the direct transaction does not otherwise require the use of the utilities' systems and is exempt from the CTC under §369. In essence, to be exempt from the CTC, §369 requires that new or incremental customer load be able to be "islanded" to demonstrate that the direct transaction does not require the use of the utilities' systems. Once this standard is met, connection to the system is allowed without invalidating the CTC exemption. This test is consistent with the evidence developed in the hearings which demonstrates that some generators do rely on the utilities' transmission and distribution systems to complete their direct transaction, while others do not.

As the City of San Diego demonstrates, whether or not the utilities' facilities are used to implement the direct transaction is a factual question. Use by the direct transaction can be distinguished from interconnection to the utilities' facilities for standby power through application of the physical test described above. This interpretation of §369 provides for very limited exemptions from the CTC while at the same time promoting efficient development of California's electricity infrastructure by not encouraging islanding of new or incremental customer load.

Comments on Alternate Decision

The alternate decision was mailed for comment on October 21, 1998. Timely comments were received from PG&E and City of San Diego. Timely reply comments were filed by City of San Diego and CCSF. We have incorporated comments in the text as appropriate.

Findings of Fact

1. The CTC applies to new customer load which is being met through a direct transaction that serves the load by delivery through the utilities' transmission and distribution facilities.

2. The CTC applies to new customer load which is being met through a direct transaction if the direct transaction cannot begin or be implemented on an ongoing basis without connection to the utilities' transmission and distribution facilities, e.g., for start-up power.

3. The CTC does not apply to new customer load that is served through a direct transaction if the direct transaction serving the new load can begin and be implemented on an ongoing basis without being connected to the utilities' transmission and distribution facilities.

4. The CTC does not apply to new customer load when the load is served through a direct transaction that does not otherwise use the utilities' transmission and distribution facilities, even if the customer is connected to the utilities' transmission or distribution facilities for purposes of standby service, unless standby power is actually delivered.

5. Shortfalls in transition cost recovery caused by exemptions can be recovered only from the members of either 1) the combined class of residential and small commercial customers or 2) all other customers, depending on which of these two broad classes the exemption covers.

6. A synchronous generator system provides its own generator excitation and can generate power without being connected to the utility grid.

Conclusions of Law

1. Certain federal and state requirements demand interconnection with utilities' systems for standby power purposes.

2. We must implement the Public Utility Code sections added by AB 1890 according to the plain meaning of the statute, applying the rules of statutory construction when necessary, and according to our duty in carrying out the public interest.

3. Section 331(c) defines direct transaction, and this definition must be applied in all sections of the statute where the term appears.

4. If a direct transaction does not require the use of transmission or distribution facilities owned by the utility, the § 369 exemption applies to the new or incremental load. An interconnection to the utility's transmission or distribution system for standby power does not negate this exemption.

5. If the direct transaction can start and operate on an ongoing basis without the parties to the direct transaction being connected to the utilities' systems, then the new customer load is exempt from the CTC under §369.

6. Whether or not the utilities' facilities are used to implement the direct transaction is a factual question that can be resolved by the parties by application of the physical test described herein.

7. Section 372 designates specific exemptions for cogeneration and self-cogeneration facilities that meet certain criteria. Sections 369 and 372 are not in conflict.

8. Sections 372(c) and 373 provide for additional opportunities for parties and utilities to seek exemptions from this Commission.

9. Section 380 provides for a waiver of standby charges for microcogenerators meeting specific criteria.

10. The provisions of §§ 330(v)(1) and 367(e)(1) establish a firewall such that the costs of CTC exemptions granted to residential and small commercial customers shall be recovered only from these customers. The exemptions established in § 369 do not contradict these firewall provisions.

11. This order should be effective today so that final transition cost balancing account tariffs and terms and conditions tariffs may be implemented as soon as possible.

FINAL ORDER

IT IS ORDERED that Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall file compliance advice letters within 7 days of the effective date of this decision to modify their tariffs regarding the Section 369 exemption for new customer load, consistent with the findings of this decision. The protest period shall be shortened to 10 days. The advice letters shall be effective as of January 1, 1998, unless the Energy Division determines that these tariffs are not in compliance with this decision.

This order is effective today.

Dated December 17, 1998, at San Francisco, California.

RICHARD A. BILAS
President
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
Commissioners

I will file a written dissent.

/s/ P. GREGORY CONLON
Commissioner

I will file a written concurrence.

/s/ JESSIE J. KNIGHT, JR.
Commissioner