BEFORE THE ENERGY COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of: Achieving the Preferred Loading Order White Paper and Exploring Issues Associated with Implementation and Distribution Planning of Distributed Generation	Docket Nos. 04-IEP-1E and 04-DIST-GEN-1

COMMENTS OF THE COGENERATION ASSOCIATION OF CALIFORNIA AND THE ENERGY PRODUCERS AND USERS COALITION ON THE 2005 ENERGY REPORT-CHP WORKSHOP APRIL 28, 2005

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May 6, 2005

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The Cogeneration Association of California[1] (CAC) and the Energy Producers and Users Coalition[2] (EPUC; jointly, CAC/EPUC) submit these comments on the 2005 Energy Report-CHP Workshop April 28, 2005. These comments are submitted to the California Energy Commission (Commission) pursuant to the notice of committee workshop in the above-noted dockets.

The *Assessment of California CHP Market and Policy Options for Increased Penetration* (CHP Report) and the CHP Workshop should make clear three facts.

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[1] CAC represents the power generation, power marketing and cogeneration operation interests of the following entities: Coalinga Cogeneration Company, Mid-Set Cogeneration Company, Kern River Cogeneration Company, Sycamore Cogeneration Company, Sargent Canyon Cogeneration Company, Salinas River Cogeneration Company, Midway Sunset Cogeneration Company and Watson Cogeneration Company.

[2] EPUC is an ad hoc group representing the electric end use and customer generation interests of the following companies: Aera Energy LLC, BP America Inc. (including Atlantic Richfield Company), Chevron U.S.A. Inc., ConocoPhillips Company, ExxonMobil Power and Gas Services Inc., Shell Oil Products US, THUMS Long Beach Company, Occidental Elk Hills, Inc., and Valero Refining Company - California. Together, CAC and EPUC member companies produce fuels, electricity and major cogeneration operations with capacity in excess of 1500 MW in California.

- First, retention of existing large CHP facilities in California is at risk and requires regulatory action now.

- Second, the focus for regulatory policies to retain and increase CHP market penetration should be on existing and new large CHP facilities and their ability to export. Policies that facilitate sales of excess CHP power from large CHP facilities to the utilities would help ensure retention of existing CHP projects and would help to restore the investment climate for development of significant new large CHP installations.

- Third, the Independent System Operator (ISO) tariffs are overly burdensome and not conducive to CHP.

These facts should guide the Energy Commission as it considers policy options to encourage CHP operations. The clear, logical conclusions are:

➢ CHP resources must be added *now* as a preferred resource to the Energy Action Plan and specified as an integral part of the Loading Order;

➢ Preservation and expansion of CHP must be an explicit and immediate goal of the 2005 Integrated Energy Policy Report (IEPR); and

➢ Policies to facilitate export from large CHP operations should focus on simple interconnection with and export to the utilities, not complex, problematic ISO tariffs and an attenuated wholesale market. Such policies would be consistent with federal law mandating utility purchase of CHP Qualifying Facility (QF) energy.

Finally, the CHP Report must correct the impression that the California Department of Water Resources (DWR) Power Charge Exemption for CHP and customer generation departing load is an incentive and results in a cost shift. The California Public Utilities Commission has expressly concluded that it does not shift costs, and the CHP Report should explicitly recognize there is no cost associated with this exemption.

I. THE CHP REPORT MUST ACKNOWLEDGE THE CURRENT, SIGNIFICANT RISK TO 1,800 MW OF EXISTING LARGE CHP; THIS RISK IS EXACERBATED BY CONTINUED REGULATORY INACTION.

The CHP Report recognizes that the majority of the existing CHP MW, 90% of the 9,130 installed CHP MW, are in large CHP facilities. A significant portion of these existing CHP facilities rely on their ability to export surplus power on terms and conditions consistent with CHP operating characteristics. The large commercial or industrial customer uses CHP primarily to supply thermal energy requirements and must be able to economically export the electrical energy associated with its thermal requirement that is produced by CHP. CHP Qualifying Facility (QF) power contracts that enable the necessary export expire at a significant rate over the next 5 to 7 years. By 2008, expired CHP QF contract capacity is expected to exceed 1,000 MW and approach 1,800 MW by 2010. *See* California Public Utilities Commission D.04-01-050, at 135-136.

The base case, where no regulatory action is taken to increase market penetration of CHP, projects an increment of almost 2,000 MW of CHP over the next fifteen years. Critically, this base case assumes that the existing CHP facilities maintain their beneficial cogeneration operations in the face of continued regulatory inaction. As demonstrated at the CHP workshop and herein, this assumption is wrong, and the magnitude of error is huge. Absent regulatory action <u>now</u>, 1,800 MW of existing CHP facilities are at serious risk. It should <u>not</u> be assumed that these facilities will remain online and operating through 2020 without any regulatory action.[3] These 1,800 CHP MW should not be included in

[3] To the contrary, the California Public Utilities Commission is currently considering a requirement that the utilities supply portfolios discriminate against gas-fired CHP in favor of

the base case projection. These existing large CHP installations might very well discontinue cogeneration operations if regulatory policies are not implemented now.

With the necessary removal of these existing CHP facilities from the base case, the corrected base case projection of incremental CHP market penetration is less than 200 MW. If all contracts for CHP QF capacity currently able to export simply and easily to the utilities are permitted to expire, the base case projection of "incremental" CHP market penetration would most likely be a *decrement.* The CHP Report base case projection should be corrected to show an expected increment of less than 200 MW, absent regulatory action.

Regulatory action and policy implementation to prevent the loss of these existing CHP resources are needed now. The importance of reliable steam supply to the industries providing the vast majority of existing CHP MW, enhanced oil recovery and petroleum refining, cannot be understated. These companies will only operate under a CHP configuration if it is economic, provides a reasonable certainty of operational longevity and does not jeopardize production of their core business product.

As noted above, CHP QF contracts have begun to expire and will continue to do so, at an alarming rate, over the next few years. This makes the ability of large CHP sites to export extra electricity uncertain. Faced with uncertainty,

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renewables in R.04-04-026. This short-sighted approach disregards entirely the significant and real natural gas savings and emission reductions achieved by CHP. According to the CHP Report, CHP natural gas savings and emissions reductions range between 400 trillion Btus of energy savings and a CO_2 emissions reduction of 23 million tons (base case) and 1,900 trillion Btus of energy savings and a CO_2 emissions reduction of 112 million tons (high deployment case). *See* CHP Report, at ix.

industrial customers will develop alternative plans to meet thermal host requirements for their core businesses. Notably, typical project lead times at industrial facilities are three years. Given these facts, it is highly likely that plans are now in place for future boiler installations at large CHP sites to meet steam demand if their ability to export excess electricity to the utilities is not protected by regulatory action. Expeditious regulatory action to protect these existing CHP resources is needed now.

The Energy Commission should immediately specifically include CHP in the Loading Order and state as a primary goal of the 2005 IEPR the preservation and expansion of large CHP resources. Critically, it is also these proven large CHP sites that offer the greatest potential for additional CHP installations.

II. LARGE CHP FACILITIES, EXISTING AND NEW, ARE THE IDEAL CANDIDATES TO APPRECIABLY INCREASE CHP MARKET PENETRATION AND SHOULD BE THE PRIMARY POLICY FOCUS.

The large CHP facilities have been and remain the ideal candidates for CHP projects. History proves that these facilities have provided the most CHP MW to the state in the past. *See* CHP Report, Figures 2.1 and at 2-1. It makes no sense to ignore the largest segments of the market that have the best track record. In fact, it would make most sense for these market segments to be the focus of an Energy Commission policy to meet its goal to increase CHP market penetration. Large CHP projects are generally privately financed and have long economic lives; they are able to achieve economies of scale. Moreover, the CHP Report cites lack of support from upper management as a key obstacle to installation of additional CHP facilities. Crucially, upper management of industrial entities with large CHP facilities have a proven interest in, as well as the ability to manage, these facilities. It should be noted that the greatest CHP end user presence at the CHP Workshop was by management of large CHP sites.

Moreover, it is these large sites that have sufficient need for thermal energy to capture all of the efficiencies of cogeneration. They can sustain the necessary level of operations to capture all of the efficiencies of the dual use of single fuel and do not need to “ramp down” their operations due to lack of thermal demand. Large CHP sites are therefore able to meet federal and state efficiency standards.

Notably, these existing sites also contain significant possibilities for the addition of CHP projects through retrofitting and expansion opportunities. The CHP Workshop discussion showed that the State has lost opportunities for significant expansion of large CHP sites. The CHP Workshop discussion revealed that when unable to export excess electricity to the utilities, entities would install boilers rather than a large CHP unit, or choose to not expand operations. The Energy Commission must recognize that the primary focus of the large CHP facilities is their core business product. Hence the logical choice for these facilities would be to install traditional boilers to meet thermal demands. Notably, Valero Refining Company – California (Valero) has an empty slot where it had hoped to install an additional large CHP unit. Valero also runs its existing turbine below full capacity to avoid participating in the ISO wholesale market. As a result, a portion of the resource is wasted needlessly despite the concern of an overall resource shortfall this summer. This could be corrected if Pacific Gas & Electric Company (PG&E) would agree to purchase the excess energy without forcing Valero to participate in the ISO wholesale market. PG&E, however, has refused to do so. Again, it should not be assumed that similarly situated sites do not plan to install boilers and either halt or not expand CHP operations if faced with an untenable situation of regulatory uncertainty and a complex and burdensome ISO Tariff.

III. ISO COSTS AND POLICIES INAPPROPRIATELY DISCOURAGE THE ADOPTION OF CHP AND DG IN CALIFORNIA.

Despite the benefits which CHP and DG (collectively Customer Generation) provide to the State, ISO policies which do not appropriately account for Customer Generation serve to discourage the installation of these technologies. Specifically, ISO policies which seek to go “behind-the-meter” to inappropriately take control of Customer Generation or impose costs on load not served by the ISO Grid, effectively eliminate many of the benefits associated with Customer Generation. This threat to the future success of CHP and DG programs may be addressed through straightforward and sensible modifications to the ISO Tariff to account for the unique operational characteristics of Customer Generation.

A. The ISO Should Not Charge, Or Collect Fees, Or Establish Billing Determinants For Customer Generation Load On Other Than A Net Load Basis.

For purposes of these comments, “Gross” and “Net” metering are two different approaches to measuring the electrical energy consumed at an integrated generation and load operation, such as a CHP or DG facility. Net load is that portion of customer load served by electric energy imported to serve a customer’s load and delivered through an Operator such as the ISO (Net Load).

Gross load is the total consumption by an end-use customer, including "Customer Generation Load" and Grid imported resources (Gross Load). "Customer Generation Load" is the end-use customer electric energy consumption served by Customer Generation.

For over twenty years of regulation, since the inception of the development of PURPA resources, retail demand served by Customer Generation in California has been metered and billed on a net basis. That is, since the inception of the ISO, costs for its services have been allocated to load based only on the portion of load actually withdrawing or injecting power to the Grid. The ISO has sought to change this well-established policy and meter and bill all load that is served by Customer Generation on a Gross Load basis as opposed to a Net Load basis. Under the ISO's Tariff, all loads that exist in the control area, whether served by Customer Generation or by energy delivered over the Grid, would be required to be separately metered, billed and even scheduled without any consideration of the integrated generation serving the load. These charges would be imposed on the entire connected load even if the connection is maintained only for the purpose of securing CPUC-jurisdictional standby service.

As one example of this, under the ISO's Participating Generator Agreement (PGA), the ISO would require Customer Generation to schedule all energy consumption and generation on a gross basis. An end-use customer that installs 15 MW of generation to supply 15 MW of electric energy consumption will be required pursuant to the provision of the PGA to schedule the 15 MW of generation to serve the 15 MW of electric energy consumption, even though no power ever flows onto or off of the end-use customer's site. The customer served by Customer Generation, while never using the distribution and transmission system or any of the ISO's facilities, would nonetheless have to pay a scheduling coordinator for scheduling the generation and electric energy consumption with the CAISO. This payment is mandated even though the CAISO-controlled Grid will never be used. While CAC and EPUC have obtained, after seven years of litigation, a FERC order establishing a Qualifying Facility (QF) PGA under which scheduling is accomplished on a net basis, the QF PGA does not apply to non-QF Customer Generation.

Additionally, absent specific exceptions achieved through litigation and/or settlement, the ISO Tariff assesses the following charges to Customer Generation as if those customers fully utilized the transmission system for the supply of their electric energy consumption.[4]

(1) Transmission-related costs in the form of Transmission Access Charges (TAC) (for the transmission of a customer's own power to the customer's load);

(2) Ancillary service charges (reserves for load not on the system and based on non-coincident peak);

(3) Grid Management Charges (GMC) (reflecting use of the system even when there is no load placed on the Grid);

(4) Imbalance charges (for deliveries of the customer's own power); and

[4] Exceptions from certain of the enumerated charges have been achieved through litigation and/or settlement at FERC. These exceptions result in QFs which take standby service being assessed certain charges on a net basis. See, *California Independent System Operator Corp.,* 104 FERC ¶ 61,196 (2003); *California Independent System Operator Corp.,* 110 FERC ¶ 61,090 (2005). In the case of the ISO's TAC, Customer Generation which takes standby would be assessed the TAC on a net basis. *California Independent System Operator Corp.,* 109 FERC ¶ 61,301 (2004).

(5) Metering and telemetry charges (behind the Meter and alleged to be for reliability purposes when there is no need for the data given Customer Generation's use of state jurisdictional standby service).

The imposition of these charges is unreasonable and inconsistent with federal precedent to the extent the loads and generation do not actually withdraw power or deliver power to the ISO-controlled Grid. This is because in transmitting energy over privately owned or dedicated wires, the energy does not flow on to the ISO controlled Grid. Rather, the generation, transmission and consumption of electric energy occurs behind the point of interface with the ISO Grid.

B. The ISO Should Not Be Allowed To Impose Regulation (e.g., Dispatch Or Curtailment Or Other Operational Obligations) On Customer Generation Not Delivered To The Grid For Export.

The most widely utilized form of Customer Generation is CHP. CHP facilities exist primarily to provide steam and other forms of thermal energy to a related industrial process whereas utility and merchant generators are usually engaged solely in the business of producing and selling electricity. Failure to recognize such differences by not limiting the reach of the ISO Tariff will jeopardize the efficiency, purpose, and cumulative benefits of Customer Generation.

As the Commission recognizes, practical operational differences exist between merchant plants and CHP facilities. Merchant plants can generally increase or decrease their production to accommodate the need for more or less electrical power on short notice. Changes to a merchant plant's scheduled maintenance outages solely impact when electrical power is produced. On the other hand, a CHP facility is designed to produce both thermal energy and electrical power through a sequential process that ties the thermal energy and electrical production together. Indeed, the development of a CHP operation is driven in large part by a need for thermal energy, not to produce and sell electricity into the market. Accordingly, a CHP facility's thermal obligations constrain the ability of the plant to increase or decrease the amount electric power produced at any given point in time. The CHP facility's maintenance outage may be directly tied to the time when the equipment using the thermal energy is scheduled for maintenance. Unduly interfering with the operation of CHP facilities, through means such as dispatch, curtailment and outage scheduling, can adversely impact the industrial process supported by the CHP. Such interference can also impair the ability of the integrated operation to provide its products and services to the marketplace. Typically, all generating units are operated by their owners at levels and under maintenance schedules that maximize both efficiency and the life of the generating unit. Operating outside of these boundaries can prematurely degrade the generating capacity of the unit over time and also result in an increased incidence of forced outages.

Accordingly, to the extent that a Customer Generation facility has not made generation available to the ISO's energy markets, such generation should not be subject to ISO dispatch or curtailment. The ISO Tariff should allow the ISO to exercise dispatch and curtailment authority only over electrical energy that fully participates in the energy or ancillary services markets. The ISO Tariff should protect from undue interference the electric energy needed by Customer

Generation to serve customer electrical load, the electrical energy needed to satisfy power purchase agreement obligations with a utility, the thermal needs of the customer, and the thermal production needed to satisfy contractual obligations. This objective of avoiding undue interference can be accomplished by carving out from a generator's total electrical output that net portion of the electrical output that is fully participating in the energy markets. Such an approach would provide the ISO with dispatch control only over that portion of the generation that fully participates in the energy markets and provide Customer Generation with the requisite contractual assurance that its non-market electrical generation will not be subject to inappropriate dispatch or curtailment tariff provisions.

C. The ISO Should Not Be Allowed To Impose Its Tariff Upon Non-Jurisdictional Transactions.

In recent cases, the ISO has attempted to force Customer Generation facilities to execute the ISO's PGA, Meter Service Agreement (MSA) and FERC jurisdictional interconnection agreement. Each of these agreements would subject the Customer Generation facility to compliance with the whole of the ISO Tariff including any pending or future amendments thereto. FERC has clarified the express situations in which Customer Generation should be required to execute such agreements and these restrictions should be appropriately reflected in the ISO Tariff.

The FERC has made its policy clear that a QF that delivers its output to on-site load and/or to the interconnected utility under PURPA falls within state jurisdiction. It has stated:

> *When an electric utility is obligated to interconnect under Section 292.303 of the Commission's Regulations, that is, when it purchases the QF's total output, the relevant state authority exercises authority over the interconnection and the allocation of interconnection costs. But when an electric utility interconnecting with a QF does not purchase all of the QF's output and instead transmits the QF power in interstate commerce, the Commission exercises jurisdiction over the rates, terms, and conditions affecting or related to such service, such as interconnections.*

Order No. 2003, Standardization of Generator Interconnection Agreements and Procedures, 104 FERC ¶61,103, at ¶813.

In short, the FERC's jurisdiction, and consequently the control of a FERC-jurisdictional utility such as the ISO, begins *only when the QF sells into wholesale markets beyond the bounds of PURPA*.

The FERC expressed a similar perspective in its order approving the original interconnection of Valero. Through its order, FERC made clear that Valero would not be required to execute a PGA or an MSA with the ISO if it did not participate in ISO Markets. The ISO sought to impose an unexecuted PGA and MSA on Valero in mid-2002. The FERC rejected the ISO's attempt to impose both the PGA and MSA on grounds that Valero would not be participating in the ISO Markets. The FERC stated:

> *Consistent with our previous finding in California ISO, we find Valero's arguments to be persuasive, since the language in the CA ISO Tariff and the pro forma PGA (as discussed in paragraph No. 12) is directed to generators that are interconnected to the CA ISO-controlled grid and that plan to participate in the CA ISO markets.*

Order Rejecting Participating Generator Agreement and Meter Service Agreement, 101 FERC ¶ 61,081, at ¶19.

The FERC reiterated a similar perspective on the question of the need for an ISO-administered MSA: *"According to the tariff definition of an 'ISO Metered Entity,' an entity must meet several conditions, one of which is that the entity will* *participate in CA ISO's markets."* Id. at ¶23. Finally, the FERC expressed its view once again in an ISO matter affecting Riverside. In its November 22, 2002 Order Denying Rehearing in an ISO matter affecting Riverside matter, FERC stated: *"We find that the CA ISO Tariff only requires entities that seek to participate in the CA ISO's markets (meaning to sell power) to sign a PGA."* 101 FERC ¶61,227, at ¶9. The ISO's Master Definitions Supplement (Appendix A) to the ISO Conformed Tariff as of August 10, 2004 defines "ISO Market" as follows: *"ISO Market. Any of the markets administered by the ISO under the ISO Tariff, including, without limitation, Imbalance Energy, Ancillary Services, and FTRs."* Accordingly, to the extent that a Customer Generation facility will not be participating in these markets, neither the ISO's PGA nor its MSA is required.

D. The ISO Tariff May Be Made Consistent With The Encouragement Of Customer Generation Through Reasonable Modification.

Reform of the ISO Tariff is necessary to stop current, and avoid future, improper attempts: (a) to exercise regulatory authority, such as dispatch and curtailment authority, over Customer Generation; and, (b) to impose charges through the inappropriate allocation of costs. Inappropriate assessment and allocation is directly attributable to the incorrect use of total potential load, or Gross Load, rather than the quantity of electricity imported utilizing the Grid, or Net Load. Using Gross Load, rather than Net Load, for assessing and billing of transmission related costs inaccurately relies upon two fictitious assumptions: (1) that the Customer Generation is dedicated to the Grid and always supplies its total output to the Grid; and (2) that the Gross Load is always imported from the

Grid regardless of the supply from Customer Generation. Such fictitious assumptions are prohibited by federal regulation and also serve to discourage Customer Generation installation.

This may be remedied by insuring that the ISO's Tariff specifically excludes from regulation and cost allocation end-use customer electric energy consumption served by Customer Generation. Customer Generation includes CHP, DG and any other type of generation that is constructed and operated wholly or in part to serve end-use load over either privately funded or utility dedicated customer facilities. A proposed modification to the ISO Tariff which would address current deficiencies and allow the ISO Tariff to be consistent with the Energy Commission's goals of encouraging Customer Generation is attached as Exhibit A.

IV. THE CHP REPORT MUST BE REVISED TO RECOGNIZE THAT THE DWR POWER CHARGE EXEMPTION FOR CHP AND CUSTOMER GENERATION DEPARTING LOAD DOES NOT SHIFT ANY COSTS.

Lastly, the CHP Report might give some the mistaken impression that the DWR Power Charge exemption for CHP and customer generation departing load is an incentive that results in a revenue loss that must be made up. (*See* CHP Report, at G-5 (remove "incentives"), H-5 ("maintain the utility's financial viability")) This must be corrected. First, the DWR Power Charge exemption is not an incentive. Second, there is no lost DWR revenue associated with the DWR power charge exemption for CHP and customer generation departing load, as DWR specifically did not contract to serve that load. The California Public Utilities Commission (CPUC) has clearly determined:

> *Granting exceptions to certain portions of the CRS for customer generation up to 3000 MW* ***will not result in any cost-shifting*** *among customers,* ***since costs for those MW were <u>not</u> incurred by DWR****.*

D.03-04-030, FOF 20, at 61 (emphasis added).

The decision to exempt CHP and customer generation departing load from the DWR Power Charge is based on the fact that load to be served by CHP and customer generation was taken into account by the utilities and DWR. DWR factored into their forecast that a certain portion of load would depart utility service to be served by CHP and customer generation; therefore DWR did not enter power purchase agreements to serve that load.[5] This is why the CPUC provided the exemption for these customers from the DWR Power Charge. The CHP Report should be corrected; the DWR Power Charge exemption is not an incentive, nor does it shift costs or cause revenue loss.

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5 *See* D.03-04-030, at 54 (*mimeo*).

V. CONCLUSION

CAC/EPUC respectfully urge the Energy Commission to include preservation and expansion of CHP as an explicit goal of the 2005 IEPR and add CHP as the second preferred resource in the Loading Order. The Energy Commission should also formulate policies to facilitate large CHP interconnections with and export to the utilities.

Dated: May 6, 2005

Respectfully submitted,

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CAC/EPUC EXHIBIT A

<u>Addition to Section XX of the ISO Tariff</u>

Customer Generation

Nothing contained in the Tariff, any Service Agreement, any Network Operating Agreement, any Participating Generator Agreement, any Meter Service Agreement, any protocol, any schedule or any appendix to same shall be construed as applying any charge, or any fee to End-use Customer electric consumption to the extent that electric energy consumption is served by Customer Generation located behind the End-use Customer Withdrawal Point. Such charge or fees shall include, but not be limited to: any transmission service charge; any transmission access charge; any ancillary service charge; any transmission congestion management charge; any scheduling charge; any scheduling, system control, and dispatch charge; any energy administration charge; any reliability administration charge; any generation imbalance service charge; any loss compensation service charge; any market administration charge; any control area service charge; any capacity adequacy charge; transmission rights charge; market support charge; regulation and frequency response charge; internal energy transaction charge; any capacity resources and obligation management charge; management service charge; any grid management charge; or any cost of recovery adder charge.

Nothing contained in the Tariff, any Service Agreement, any Network Operating Agreement, any Participating Generator Agreement, any Meter Service Agreement, any protocol, any schedule or any appendix to same shall be construed as affecting in any way the ability of Customer Generation to serve: (1) any End-use Customer electric consumption to the extent that electric energy consumption is served by Customer Generation located behind the End-use Customer Withdrawal Point or (2) any Thermal Requirement of a Cogeneration Facility.

Nothing contained in the Tariff, any Service Agreement, any Network Operating Agreement, any Participating Generator Agreement, any Meter Service Agreement, any protocol, any schedule or any appendix to same shall be construed as requiring the installation of any metering, any monitoring, any control equipment or any telemetering to monitor Customer Generation output that is not injected into an Operator's grid.

Definitions:

Operator: The California Independent System Operator Corporation.

Customer Generation: Generation that includes renewable power, cogeneration, distributed generation, fuel cells or any other type of generation that is constructed and operated wholly or in part to serve End-use Customer load over either privately funded or utility, customer-dedicated facilities.

End-use Customer Withdrawal Point(s): The point(s) of the End-use Customer's interconnection with the Operator's publicly dedicated wires; typically located at the site boundary. The metering of power flowing into the End-use customer's facility may occur at different points in which case consolidated power flows recorded at multiple points will be used to establish the demand.

Utility Dedicated End-use Customer Facilities: Facilities that are dedicated to a specific customer or set of customers in order to provide interconnection to the Operator's Grid. Such facilities are not dedicated for public use and are distinguished from Operator's publicly dedicated wires and Operator facilities. For the purposes of establishing the End-use Customer Withdrawal Point there is no difference between private facilities and utility dedicated customer facilities.

End-use Customer: A purchaser of electric power who purchases such power to satisfy its energy consuming equipment and who does not resell the power. An End-Use Customer must have as its Designated Agent or, in the case of a bundled customer, be included in the aggregated load of a Scheduling Coordinator.

Cogeneration Facility: The equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam) and commonly referred to as Combined Heat and Power (CHP), used for industrial, commercial, heating, or cooling purposes through the sequential use of energy.

Thermal Requirement: The thermal energy required to sustain any industrial or commercial process, or sustain any heating or cooling application.