# ATTACHMENT A

# "Conformed" Version of D.10-12-055

 **Date of Issuance April 19, 2011**

Decision 10-12-055, as modified by D.11-04-033

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

| | |
|---|---|
| Order Instituting Rulemaking on the Commission's Own Motion into combined heat and power Pursuant to Assembly Bill 1613. | Rulemaking 08-06-024 (Filed June 26, 2008) |

**DECISION GRANTING, IN PART, AND DENYING IN PART, JOINT PETITION OF PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY FOR MODIFICATION OF DECISION 09-12-042**

## 1. Summary

This decision grants in part, and denies in part, a joint request by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (collectively referred to as the "Joint Utilities") to modify Decision (D.) 09-12-042, which implements Assembly Bill 1613 (Ch. 713, Stats. 2007) (AB 1613). This decision:

1. Revises the methodology for setting the price to be offered by the electrical corporations to utilize pricing inputs from the most recent Market Price Referent (MPR) in effect at the time of contract execution instead of the 2008 MPR (Section 4);

2. Corrects language in the adopted form contracts to clarify that the "Fixed Price Component" of the price is to be a constant value during the entire contract term, and is based on the Term Start Date (Section 5);

3. Clarifies that greenhouse gas (GHG) compliance costs are not included in the MPR-based portion of the AB 1613

price formula and are instead addressed as a separate pass-through component of the AB 1613 price (Section 6);

4. Rejects the Joint Utilities' request that the AB 1613 price be reduced to the price paid to "as available" resources (Section 7);

5. Rejects the Joint Utilities' request to remove language from D.09-12-042 requiring the utilities to purchase GHG allowances on behalf of AB 1613 CHPs, but allows the AB 1613 CHPs the option of procuring their own GHG allowances, and sets a cap on GHG compliance costs to ensure any payment or procurement for GHG cost compliance complies with avoided cost principles (Section 8);

6. Makes modifications to the form contracts approved in D.09-12-042 to clean up contractual language (Section 9);

7. Rejects the Joint Utilities' proposal to include a line loss factor in the time of delivery calculation and instead provides that line losses be calculated as part of the interconnection process (Section 10);

8. Directs parties to work on a contract for AB 1613 CHPs less than 500 kilowatts (Section 11); and

9. Modifies and clarifies D.09-12-042 to be consistent with subsequent orders issued by the Federal Energy Regulatory Commission (FERC) (Sections 7 and 12).

## 2. Background

Decision (D.) 09-12-042 (Decision) adopted policies and procedures for purchase of excess electricity from eligible combined heat and power (CHP) systems by an electrical corporation under Assembly Bill (AB) 1613 (Ch. 713, Stats. 2007). Among other things, this decision adopted a standard form contract available to all eligible CHP systems up to 20 megawatts (MW) and a simplified form contract for eligible CHP systems that export no more than 5 MW. Pricing under the AB 1613 form contracts was based on the costs of a proxy natural gas generation resource, and a location bonus was applied to eligible CHP systems located in high-value areas.

On January 20, 2010, the Joint Utilities together filed an application for rehearing of the Decision on the grounds that the pricing established in D.09-12-042 is preempted by federal law and violates the ratepayer indifference standard in AB 1613. On the same day, the Alliance for Retail Energy Markets also filed an application for rehearing. On April 26, 2010, the California Public Utilities Commission (the Commission or the CPUC) issued D.10-04-055 denying both rehearing applications.

On February 2, 2010, the Joint Utilities timely filed this Joint Petition for Modification (Joint Petition) pursuant to the requirements of Rule 16.4 of the Commission's Rules of Practice and Procedure. In filing the Joint Petition, the Joint Utilities seek to address alleged problems with the implementation of the D.09-12-042 as it currently stands.[1]

On March 4, 2010, California Clean DG Coalition (CCDC), San Joaquin Refining Company (San Joaquin), and Fuel Cell Energy (FCE) filed responses to the Joint Petition. The Utility Reform Network (TURN) and Division of Ratepayer Advocates (DRA) jointly filed a response to the Joint Petition on March 4, 2010.

On May 4, 2010, the Commission submitted a petition for declaratory order to the FERC to find that the Federal Power Act (FPA), the Public Utility

[1] The Joint Utilities asserted that they did not waive the claims separately raised in their Application for Rehearing.

Regulatory Policies Act of 1978 (PURPA) and FERC regulations do not preempt the Commission's decision to require California utilities to offer a certain price to CHP generating facilities of 20 MW or less that meet energy efficiency requirements. On May 11, 2010, the Joint Utilities filed a separate petition for declaratory order with the FERC in which they argued that the Commission's decision is preempted by the FPA insofar as it sets rates for electric energy that is sold at wholesale.

On July 15, 2010, FERC issued an order granting in part and denying in part the cross-petitions for declaratory order (FERC Declaratory Order), which found: that "[a]lthough the CPUC has not argued that its AB 1613 program is an implementation of PURPA, we find that to the extent the CHP generators that can take part in the AB 1613 program obtain Qualifying Facility (QF) status, the CPUC's AB 1613 feed-in-tariff is *not* preempted by the FPA, PURPA or FERC regulations, subject to certain requirements."[2] The requirements were that: (1) the CHP generators … are QFs pursuant to PURPA; and (2) the rate established by the CPUC "does not exceed the avoided cost of the purchasing utility.[3]

On August 16, 2010, the Commission filed with FERC a request for clarification, or, in the alternative, a request for rehearing, which sought clarification regarding the avoided cost rates for facilities participating in the AB 1613 program.

On September 9, 2010, the Commission issued an Amended Scoping Memo and Ruling. This Ruling amended the November 4, 2008 Scoping Memo

---

[2] *California Public Utilities Commission et al.*, 132 FERC ¶ 61,047 at 65.

[3] *Id.* at 67.

to account for issues related to the FERC Declaratory Order and asked for further comment on certain issues brought up in the Joint Petition. On September 29, 2009, DRA filed a response to the Amended Scoping Memo. Comments in response to the Amended Scoping Memo were filed by the Joint Utilities, DRA, FCE, CCDC, San Joaquin, and Sustainable Conservation. Joint comments were filed by Pacific Corp and Sierra Pacific Power Corps (the Multijurisdictional Utilities).

On October 21, 2010, FERC issued an order, which granted the Commission's August 16, 2010 request for clarification (FERC Clarification Order).[4] In this order, FERC clarified that the state has a wide degree of latitude in setting avoided cost, can utilize a multi-tiered avoided cost rate structure, and that this approach is consistent with the avoided cost requirements set forth in Section 210 of PURPA.

### 3. The Joint Petition and Amended Scoping Memo

In their Joint Petition, the Utilities request the Commission modify D.09-12-042 to:

- Update the formula for calculating the price to be offered by the electric corporations in the standard and simplified contracts to utilize components from the 2009 Market Price Referent (MPR) instead of the 2008 MPR;
- Modify Exhibit C of the standard contract and Exhibit B of the simplified contract to clarify that the "Fixed Price Component" of the price to be offered is constant throughout the contract term;
- Reduce the price to be offered under AB 1613 contracts to reflect an as-available price;

[4] *California Public Utilities Commission*, 133 FERC ¶ 61,059.

- Remove the language from D.09-12-042 requiring the utilities to purchase greenhouse gas (GHG) allowances for CHP Sellers under certain circumstances; and
- Modify certain provisions of the form contracts attached to the Decision to clarify the language and contractual provisions.

The Amended Scoping Memo also asked for further clarification on a number of these issues. We consider each of the requests in the Joint Petition, as further informed by comments received in response to the Amended Scoping Memo, in Sections 4 through 12 below.

## 4. Updating Pricing Formula to Use 2009 MPR Inputs

The pricing formula adopted in D.09-12-042 is based on the utilities' avoided costs associated with a combined cycle gas turbine. Several inputs in the adopted pricing formula come directly from the 2008 MPR. The MPR is set annually by the Commission in accordance with Pub. Util. Code § 399.15(c) and represents the long-term market price of electricity. The MPR is used as a benchmark in the Renewables Portfolio Standard Program.

The methodology for calculating the MPR was first developed in D.04-06-015. The methodology has been revised several times since, in D.05-12-042, D.07-09-042, and most recently in D.08-10-026. Each year the Energy Division updates the cost inputs and recalculates the MPR based on this methodology.

The AB 1613 pricing formula utilizes several inputs from the 2008 MPR. These inputs include:

- Fixed Component = MPR fixed component for 10 year contract;
- Variable Operations & Maintenance = MPR variable Operations & Maintenance;

- Heat Rate[5] = MPR average heat rate for a combined cycle gas turbine; and
- Time of Delivery periods and factors.

Joint Utilities argue that the 2009 MPR, which was adopted by the Commission at the same meeting as D.09-12-042, is more up-to-date and therefore contains the most appropriate inputs to be used in the pricing formula for the AB 1613 contracts.

TURN and DRA agree with the proposed modification to use the 2009 MPR inputs instead of the 2008 MPR inputs. TURN and DRA suggest that this will reduce the cost to ratepayers.

San Joaquin generally opposes the Joint Utilities' request to modify the AB 1613 pricing formula. San Joaquin contends the Joint Utilities are simply rearguing the same points that the Commission considered and rejected in D.09-12-042. Although San Joaquin does not oppose the Joint Utilities' proposal to use pricing inputs from the 2009 MPR, it questions why this request was not made when the decision was pending. San Joaquin believes the Commission should only approve the proposed modification with the following conditions:

- Modification should only be allowed when the resulting change to the pricing formula is material (more than 5%);
- All MPR values used in the AB 1613 pricing formula should be updated, not just the limited values proposed by the Joint Utilities;
- The Commission should clarify that all updates to AB 1613 prices will occur regardless of whether the update results in an increase or decrease of the price; and

---

[5] Heat Rate is expressed as the number of British Thermal Units required to generate a kilowatt hour of electricity.

- Updates of AB 1613 prices should have prospective application only.

San Joaquin argues that there is no need to change the pricing option to use the 2009 MPR because the resulting price change would be immaterial. However, San Joaquin does not oppose future changes to the adopted MPR values if they result in a material impact.

FCE opposes the Joint Utilities' proposals to alter the pricing approach adopted by the Commission in D.09-12-042. It states that the Joint Petition does not offer any new legal argument or cite changing facts warranting the proposed changes. Specifically, FCE opposes the Joint Utilities' proposal to replace the 2008 MPR adopted in D.09-12-042 with the 2009 MPR because the Joint Utilities have failed to provide any substantive discussion in support of their proposal.

CCDC states that the simplified contract is the product of extensive collaborative efforts by the parties and characterizes the Joint Utilities' request as a unilateral attempt to modify certain provisions. CCDC contends it is not clear whether the Joint Utilities propose replacing the entire 2008 MPR or just the fixed component. Regardless, CCDC does not support replacing the 2008 MPR with the 2009 MPR. If however, the Commission decides to update the MPR, CCDC argues it should do so only if other than a *de minimus* change in the total MPR value has occurred and only if all the components are updated – not just those that result in a better price for the Joint Utilities.

### 4.1. Discussion

As discussed in D.09-12-042, the adopted pricing formula utilizes components of the MPR, as the cost of a proxy natural gas generation resource is a reasonable proxy for the marginal unit avoided by an eligible CHP facility. At the time the Decision was adopted, the most current MPR available was the 2008 MPR.[6]

Given our determination that the cost of a proxy natural gas generation resource should serve as a basis for determining the price to be offered to eligible CHP facilities under the AB 1613 program, it is reasonable that the pricing formula reflects the most current cost of a proxy natural gas generation resource. Since the MPR itself is not static, but is updated to reflect the dynamics of the market, it logically follows that the most current MPR inputs should be used in the pricing formula adopted in D.09-12-042. Therefore, going forward, the pricing formula in the form contracts shall be updated to reflect the most current MPR.[7]

We decline all proposals to make the use of the most current MPR contingent upon a more than *de minimus* change in the total MPR value. Neither CCDC nor San Joaquin has provided a sufficient basis to impose this requirement. If the pricing formula is to be based upon the most up-to-date inputs available, then the amount of change from the previous value (up or down) is irrelevant to our determination to utilize to the most current MPR.

As long as the MPR is calculated based on the costs of a proxy conventional natural gas generation resource, the four pricing components identified above from the most recent MPR shall be used in the AB 1613 pricing formula in order to determine the utilities' avoided cost for this program. Each year, upon adoption by this Commission of a new MPR calculation, each

---

[6] The Commission adopted the 2009 MPR on the same day that it adopted D.09-12-042.

[7] New contracts would utilize the 2009 MPR until the 2010 MPR is adopted by the Commission.

California investor-owned utility (IOU) shall file a Tier 1 Advice Letter updating its AB 1613 tariffs and standard contracts with the new MPR inputs. The advice letters shall be filed and served within five days of the date that the order adopting the MPR is mailed. If, however, the MPR ceases to be based on a proxy natural gas generation resource or ceases to exist entirely, then the most recent MPR inputs that were developed using a proxy conventional natural gas generation resource shall continue to apply to AB 1613 contracts until otherwise modified by this Commission.

Updated pricing inputs shall only apply to new contracts executed after the effective date of this decision. The pricing for executed contracts shall be based on the pricing inputs in effect at the time the contract was executed. We do not require parties to modify contracts that have already been executed because it is important to protect contract stability and the expectations of the contracting parties.

## 5. Clarification of Fixed Price Component

Exhibit B of the simplified contract and Exhibit C of the standard contract, as proposed by the working group to Rulemaking 08-06-024 (R.08-06-024), included the pricing formula for each contract. In adopting the standard contract, the Commission added language and tables to Exhibit C, Section 3 to reflect the fixed price component of the AB 1613 form pricing. Both the table and added language reflect escalating prices based on the 2008 MPR. The added language was as follows:

> …the Fixed Price Component of the Monthly Contract Payment shall be the amount in the following table for the year in which the payment is being calculated.

The Joint Utilities contend the added language is in error because, taken literally, the language implies that the fixed component should escalate every year. The Joint Utilities believe that the MPR already assumes an escalation in the fixed component and has levelized that escalation so that the payments are the same during the entire period of the contract.

DRA and TURN support modification of the contract language to correct the "Fixed Price component" of the price paid to clarify that it is a constant value during the entire term of the contract.

FCE supports the Joint Utilities' proposed revision to Section 3 in Exhibit C of the standard contract to clarify that the MPR fixed price component be the amount identified for the year "in which the Agreement was executed by the Parties." However, FCE contends that the proposed redline does not match the language in Exhibit C.3 of the less than 20 MW contract and Exhibit B.3 of the Small CHP contract which refers to "the year of the Term Start Date." FCE believes it is important that the CHP contracts clearly show that, for purposes of determining the fixed price component, the relevant year is the year in which the facility initiates deliveries to the utility. FCE suggests that to eliminate any ambiguity the definition of the Term Start Date be revised to refer to the "initiation of commercial operation" or other similar language.

San Joaquin agrees with the Joint Utilities' proposal to clarify that the fixed price component of the AB 1613 price is constant over 10 years. San Joaquin disagrees with the Joint Utilities, however, about when that price is fixed. San Joaquin contends that the MPR fixed components shown in the table are determined based on the year in which a project comes on line.

CCDC agrees with the Joint Utilities that the MPR-based fixed component includes a levelized escalation for the term of the contract. CCDC generally agrees with the Joint Utilities' proposed revision to Section 3 of Exhibit C. However, CCDC notes there is some ambiguity between the revision proposed by the Joint Utilities in the text of the Joint Petition and the revision proposed in

Exhibit C of the standard contract. CCDC conditions its support on its belief that the Joint Utilities intended that Section 3 of Exhibit C be revised to clarify that the fixed price component will be the amount for the year of the "Term Start Date" and that the reference to the year of execution in the text of the Joint Petition is an inadvertent error.

### 5.1. Discussion

We agree that the language added by D.09-12-042 is in error and that the fixed price component of the contract price does not escalate during the contract term. We also agree with FCE, San Joaquin, and CCDC that the fixed component should be based on the year in which a project is expected to begin commercial operation or come online, which is synonymous with "Term Start Date," and not the year in which the contract is signed. The "Term Start Date" is defined within Section 1.01 of the adopted contracts as the date that the project starts, in other words, the year in which a project is expected to come online, not the date the contract is signed. We therefore, modify the language of Section 3 of Exhibit C of the standard contract as follows:

> The Fixed Price Component, "FPC," for all TOD Periods shall be the amount in the following table for the year of the Term Start Date.

## 6. GHG Compliance Costs Not in Fixed Price Components

The fixed component of the AB 1613 pricing formula is defined as the "Fixed Component of the 2008 MPR minus GHG compliance costs, in $/kWh [kilowatt hour] based on 10-year contract."[8] The Joint Utilities ask the Commission to clarify whether: (1) GHG compliance costs that are referenced in the contract should be subtracted from the fixed component; (2) the GHG adder

---

[8] See D.09-12-042 at 34, Table 2.

in the 2008 MPR should be subtracted from this fixed component; or (3) D.09-12-042 merely seeks to convey that the GHG adder in the 2008 MPR adder should not be included in this payment calculation, because GHG compliance costs are dealt with elsewhere in the contract.

FCE agrees that this point should be clarified and contends that the Joint Utilities' third interpretation is the correct characterization. It further points out that the Commission states in the Decision that the adopted approach was to have "GHG costs handled directly in the contract as a cost pass through instead of including an administratively established 'adder' in the contract price."[9] FCE does not object to this clarification of their perception of the Commission's intent.

TURN and DRA also agree that there should be some clarification on this point but do not offer any suggestion as to what that clarification should be. Although CCDC believes the Commission was clear in D.09-12-042 that the GHG adder is not already included in the AB 1613 payment calculation, it does not object to the modification proposed by the Joint Utilities if only to put an end to any efforts to further reduce AB 1613 payments.

### 6.1. Discussion

We agree that language adopted in Table 2 of D.09-12-042 may cause some confusion. This ambiguity stems from the fact that the fixed component of the 2008 MPR, upon which the AB 1613 pricing was based, does not include a GHG adder. GHG compliance costs in the MPR calculation are embedded in the variable component of the 2008 MPR. The Commission's intent in D.09-12-042 was to clarify that GHG compliance costs were not being paid for twice, once in the price and once as a pass through as a contract term. However, the language

[9] See FCE Response on the Joint Petition to Modification at 4.

in D.09-12-042 apparently created some ambiguity. We agree with FCE and CCDC, the proper interpretation is that the GHG adder in the 2008 MPR variable component should not be included in the pricing formula, as GHG compliance costs are addressed elsewhere in the CHP contract. We therefore, clarify that since the fixed price components of the MPR do not include a GHG adder, and GHG compliance costs are not reflected in any way in the adopted pricing formula, no additional subtraction is necessary. GHG compliance is addressed in the contracts as a direct pass-through of actual compliance costs from the Seller to the Buyer. It does not need to be considered in the pricing formula adopted in D.09-12-042. We therefore, modify Table 2 to remove the phrase "minus GHG compliance costs."

### 7. Pricing of Power as an "As Available" Resource

The Joint Utilities ask the Commission to reduce the price paid under the Form Power Purchase Agreements to reflect the fact that eligible units are "as available" resources. The Joint Utilities contend that D.09-12-042 erred in concluding that the eligible CHP systems are likely to operate as if they were a firm resource and that the factors applied to the MPR and proposed in the adopted pricing formula account for the value of different products such as baseload and as available electricity.

FCE opposes the Joint Utilities proposal to reduce the feed-in-tariff price to reflect that CHP resources are "as available" because it is nothing more than repetition of arguments considered and rejected in D.09-12-042.

CCDC objects to the Joint Utilities' proposal to reduce the AB 1613 price to reflect pricing for an as available product. CCDC contends the proposal is based upon the same arguments previously raised in the underlying proceeding that the Commission previously rejected. There the Commission explained that the time-differentiated MPR pricing mechanism specifically accounted for the value of different products, including the difference in value between baseload and as-available electricity. CCDC contends that the Commission appropriately recognized that the MPR does differentiate between as available and firm baseload power. As a result, CCDC contends the Commission should reject the Joint Utilities' proposal to reduce the price under AB 1613 contracts to reflect an as-available product.

### 7.1. Discussion

The arguments raised by the Joint Utilities are similar to those raised in both the underlying proceeding and their joint application for rehearing of D.09-12-042. The Commission has already considered and rejected similar arguments in D.09-12-042 and D.10-04-055.[10] The logic set forth in those decisions, while not focused on avoided cost principles, remains valid and supports our conclusion here: Paying AB 1613 generators an "all in" price for as-available energy that is calculated based on the long term costs of constructing and operating a proxy baseload resource is appropriate and does not exceed the utilities' avoided costs because AB 1613 CHPs operate as firm resources and avoid capacity procurement for the utilities. We provide further clarification on this point here to resolve any questions that remain.

#### 7.1.1. AB 1613 Requires Eligible CHPs to Operate As Firm Resources And Allows Procuring Utilities to Avoid Resource Adequacy Obligations

AB 1613 CHPs are required by statute to operate as firm resources. Public Utilities Code §§ 2843(a)(2) and (3) require that an eligible CHP system must "be

[10] See D.09-12-042 at 36.

sized to meet the eligible customer-generator's thermal load," and must "operate continuously in a manner that meets the expected thermal load and optimizes the efficient use of waste heat." Consistent with this obligation, § 2841(f) provides that the utilities are entitled to count the firm resource towards their resource adequacy obligations. These obligations are reflected in Sections 1.02 and 3.02 of the *pro forma* contracts approved in D.09-12-042, which require the generator to commit to an expected amount of energy production per term year and to pledge its generating capacity to the purchasing utility to use in meeting its resource adequacy obligations. Significantly, when a utility contracts with an AB 1613 CHP, it avoids a resource adequacy procurement obligation equivalent to the *full capacity* of the AB 1613 CHP (in other words, all of the power generated by the CHP), but the CHP is not paid for the full value of this avoided cost. Instead, the generator only receives a payment for the excess energy it sells to the utility. Thus, this payment clearly does not exceed the utility's avoided CCGT procurement costs.

### 7.1.2. FERC Rulings Recognize A State's Ability To Compensate QFs For Their Capacity Value

The Joint Utilities' continued attempts to challenge the firm/as available decision made by this Commission are troubling given the support for the Commission's actions. FERC expressly affirmed a state's ability to "determine that capacity is being avoided, and so … rely on the cost of such avoided capacity to determine the avoided cost rate" – which is exactly what the Commission is doing here.[11] FERC went on to state:

---

[11] *California Public Utilities Commission*, 133 FERC ¶ 61,059 at 26.

> Further, in determining the avoided cost rate, just as a state may take into account the cost of the next marginal unit of generation, so as well the state may take into account obligations imposed by the state that, for example, utilities purchase energy from particular sources of energy or for a long duration.[12]

Here, consistent with AB 1613 requirements, the Commission has determined that an AB 1613 CHP will avoid capacity costs that the utility would otherwise incur, and quantifies those costs based on the marginal CCGT.

Reliance on a CCGT as the marginal unit is reasonable because, as we have determined in all of the CHP decisions, it is much more likely that the Joint Utilities would seek to meet the baseload needs served by AB 1613 CHPs through a long term contract with a new, highly efficient CCGT. Among other things, the Commission's emission performance standards adopted in D.07-01-039 would likely compel such an outcome. That decision prohibits the utilities from entering into contracts of five years or longer with facilities that emit in excess of 1100 lbs/MWh of carbon dioxide equivalent. In effect, this means that the utilities are limited to procuring long term commitments[13] for sales of electricity from CCGTs, renewables, other non-carbon emitting resources such as hydroelectric power, and CHPs.[14]

---

[12] *Id.*

[13] For GHG emissions purposes, Pub. Util. Code § 8340(f) defines a "Long-term financial commitment" to mean a new or renewed contract for a term of five years of more. Pub. Util. Code § 8341(a) prohibits the utilities from entering into contracts of 5 years or more for baseload generation that does not comply with the Commission's GHG emission performance standards. While an AB 1613 CHP may contract for a term of one to ten years, we anticipate most AB 1613 CHPs to contract for ten years for financing purposes.

[14] See, e.g., D.07-01-039 at Findings of Fact 2, 3, and 4.

A payment for capacity value based on avoided procurement is not new policy. FERC addressed this very issue when it adopted Order 69 implementing Section 210 of PURPA in 1980. In response to claims that avoided cost should not include capacity payments, FERC explained that purchases of power from QFs "will fall somewhere on the continuum between" firm and non-firm service or capacity and energy. For facilities that demonstrate "a degree of reliability that would permit the utility to defer or avoid construction of a generating unit or the purchase of firm power from another utility, then the rate for such a purchase should be based on the avoidance of both energy and capacity costs."[15] As AB 1613 CHPs must, pursuant to statute, provide this degree of reliability and allow the utility to avoid local resource adequacy procurement, they provide both energy and capacity and are properly compensated for both under the AB 1613 price formula.

## 8. GHG Compliance

This issue was addressed in both the Joint Utilities' Petition for Modification and the Amended Scoping Memo.

### 8.1. The Joint Petition

The Joint Utilities request that the contract provision that utilities must purchase GHG allowances on behalf of CHP Sellers (Sellers) be removed. The Joint Utilities reason that they should have the choice to procure allowances on behalf of Sellers, but should not be required to do so. The Joint Utilities claim that emissions allowance decisions are complex and that in order to procure

[15] Order No. 69, FERC Stats. & Regs., Regs. Preambles, 1977-1981, ¶ 30, 128 at 30,882 (1980).

allowances on behalf of Sellers they will need more detailed information from Sellers.

DRA, TURN, and San Joaquin do not object to the proposal to modify the D.09-12-042 to remove the requirement that utilities procure GHG allowances on behalf of small Sellers. FCE similarly does not object to eliminating the requirement that the utilities procure GHG allowances on behalf of Sellers provided the Commission includes language acknowledging that many issues regarding GHG responsibilities and compliance are currently unresolved and that the Commission reserves the right to order the utilities to obtain allowances on behalf of the Sellers if doing so is necessary in order to effectuate the objectives of AB 1613.

CCDC supports the proposal to eliminate the utilities' obligation to procure GHG allowances on behalf of the Sellers but believe the utilities should have the option to do so on behalf of Sellers. CCDC suggests that D.09-12-042 be modified to make clear that the adopted GHG strategies are subject to revision pending implementation of GHG rules. Alternatively, CCDC proposes that the Commission modify the D.09-12-042 to require the utilities to work with Sellers under AB 1613 contracts to develop the most efficient, cost-effective strategy for GHG compliance with the excess energy sold under AB 1613 contracts.

### 8.2. The Amended Scoping Memo

The Amended Scoping Memo issued on September 9, 2010, sought additional comments on this issue. Specifically, the Ruling asked:

(1) If Sellers require reimbursement for GHG allowance costs, at what intervals should invoices be submitted to the Buyers?

(2) Is a test (market based or some other method) needed to ensure that the invoices submitted by the Seller leave the ratepayer no worse off than if the Buyer had

> managed these compliance costs? If so, how should the market test be structured?

Party comments reflected a wide range of views on these two questions. San Joaquin suggests that Sellers should submit invoices at the same frequency that GHG allowances are bought and sold through the auction mechanism. San Joaquin expects this to occur either quarterly or monthly. SDG&E contends that Sellers should submit an invoice for GHG reimbursement at least once per year, but no more than once per quarter. CCDC suggest that Sellers submit invoices as soon as practicable following the Seller's receipt thereof. DRA does not believe that the Commission should alter its original Decision. However, if Sellers are allowed to manage their own allowances, DRA suggests that invoices should be submitted at least annually.

PG&E and SCE reference the FERC Declaratory Order and argue that compensation to a generator cannot exceed the costs avoided by the purchasing utility. Therefore, the cost of GHG allowances should not be treated as a generator cost but as a component of the utility's avoided cost and included in payments due under the Seller's monthly invoice for delivered energy. SCE contends that any resolution of issues related to GHG costs must be consistent with the global QF Settlement Agreement[16] (QF Settlement) filed with the Commission on October 8, 2010 and PG&E, in their reply comments, agrees with SCE. FCE and CCDC reply that the Commission should ignore these comments as they are outside the scope of the Ruling and therefore erroneous.

---

[16] *Joint Motion for Approval of Qualifying Facility and Combined Heat and Power Program Settlement Agreement,* filed in the following dockets: Application 08-11-001, R.06-02-013, R.04-04-003, R.04-04-025, and R.99-11-022.

Regarding the question of whether a test is needed to ensure that the ratepayer is left no worse off if Sellers manage their own allowances, CCDC, FCE and San Joaquin agree that no such test is needed. However, SDG&E and DRA believe that a test is needed. SDG&E argues that the simplest method would be to apply auction prices to the net allowances needed based on the volume of electricity delivered for the invoiced period of time. DRA proposes a two-point test based on the average prices the Seller and Buyer pays for allowances in the market during the year. In their reply comments, PG&E disagrees with any receipt-based approach to GHG cost reimbursement.

### 8.3. Discussion

#### 8.3.1. The Pricing Terms Established By The QF Settlement Do Not Apply To The AB 1613 Program

We agree with FCE and CCDC that comments from PG&E and SCE regarding short run avoided cost calculations, as provided in the QF Settlement, are outside the scope of the Amended Scoping Memo and outside the record of this proceeding, and should therefore be disregarded.[17] Furthermore, the QF Settlement as proposed does not seek to modify any of the issues raised in this docket; so while the two matters are related, for the purposes of this issue of GHG allowance procurement associated with the AB 1613 program, any reference to a QF Settlement should have no impact on this Decision.[18]

---

[17] With respect to the table entitled "Illustrative Levelized Price Comparison" included by PG&E and SCE in their joint comments to the proposed decision filed on December 6, 2010, neither the table nor the underlying data is part of the record in this proceeding. Thus, they must be disregarded.

[18] The QF Settlement decision, D.10-12-035, expressly declined to apply the QF Settlement price to AB 1613 CHPs:

*Footnote continued on next page*

### 8.3.2. Modification To Provision Regarding Procurement of GHG Allowances

The Joint Utilities make a reasonable request in their Petition for Modification regarding which entity is best positioned to actually purchase the GHG allowances needed for an AB 1613 facility. The comments from CCDC and others suggest that the original Commission determination that the Buyer must procure the GHG allowances on behalf of the Seller might not yield the optimum outcome. Sellers that are obligated to comply with GHG regulations[19] might be better suited to procure allowances for emissions associated with their exported electricity, because it is a function they will already be performing for emissions associated with their heat needs and on-site electricity consumption.

We agree with CCDC that the original Commission determination may not yield the optimum outcome. However, unlike the Joint Utilities original petition to modify, having the Seller be solely responsible to procure GHG allowances may not yield the optimum result either. Therefore, we determine that a better outcome is for the Seller to elect who (the Buyer or the Seller) will procure the GHG allowances associated with their exported electricity.

---

> The Proposed Settlement is comprehensive, but it does not resolve issues in numerous Commission proceedings implementing recent statutory requirements that pertain to QFs of 20 MW or less, such as new CHP systems under Assembly Bill 1613 (codified as Pub. Util. Code sections 2840-2845), except to acknowledge that the megawatt (MW) and GHG reductions will count toward the investor-owned utilities' MW and GHG reduction targets.

[19] As currently proposed in ARB's Proposed Regulation to Implement the California Cap-and-Trade Program (October 2010), only facilities that produce more than 25,000 tonnes of carbon dioxide equivalent per year are "covered entities" and obligated to comply with GHG regulation during the first compliance period. Small generators will be covered upstream beginning in 2015.

Therefore, we modify D.09-12-042 to provide the Seller the option of procuring the GHG allowances for electric power sold to the utility on its own behalf or electing to have the Buyer perform this function.

If the Seller elects to have the Buyer procure the GHG allowance, the Seller will be required to provide the Buyer with sufficient information regarding the emissions associated with their power sold to the electric utility. Provided that the Seller conveys accurate emissions information to the utilities in a timely fashion, we do not find that this will present a significant hardship to them. As was originally reasoned in D.09-12-042, the utilities will be managing GHG compliance obligations for their owned generation and will be well-suited to manage GHG allowances and compliance costs. Additionally, the combination of the adopted contracts, customer meter data, and the annual reporting requirements to the ARB will provide sufficient information for the utilities to make informed decisions regarding the compliance obligation from these resources. Once ARB finalizes its cap-and-trade regulations, Energy Division staff will issue (via Resolution) guidelines on the mechanics of this exchange (e.g., information that Sellers need to provide to the utilities, timing and frequency of the utility provision of allowances, etc.).

However, based on party comments, we expect that some Sellers will elect to manage their own GHG allowances. The Amended Scoping Memo asked the parties if it should employ a test in order to protect ratepayer interests. As commented on by San Joaquin, no test should be needed as long as the Seller purchases the allowance through a liquid and transparent market, and in a manner that is timely in terms of when the allowance must be surrendered to the regulators of the GHG program. PG&E agrees that the price paid for the allowances should be based on a public index, with the best option being the publicly available auction price. We agree. When the Seller elects to procure an allowance that will be reimbursed by the Buyer, the amount paid should be equal to the price established by the most relevant publicly available index, such as an auction, or other comparable index.

#### 8.3.3. Modification To GHG Compliance Cost Pass-Through To Be Consistent With Avoided Cost Principles

In determining how to best allocate GHG compliance costs the Commission initially focused on the preliminary and evolving nature of the GHG compliance regulatory regime. As the Final Staff Proposal noted:

> It is difficult to know the value of GHG attributes and GHG compliance costs, if any, associated with eligible generation under this program until rules and regulations are established.[20]

The Final Staff Proposal therefore proposed that GHG compliance costs be addressed as a direct cost pass-through from the AB 1613 CHP to the utility buyer.

The Commission similarly recognized that California's GHG compliance regime was in its infancy. Because compliance will not begin until January 1, 2012, at the earliest,[21] the regime will not apply to all facilities at that time, and many critical elements of the regime have not yet been finalized, the Commission could not accurately quantify the costs the GHG compliance regime would

---

[20] Final Staff Proposal at 5. The Final Staff Proposal was Attachment A to the "Administrative Law Judge's Ruling Incorporating Energy Division Final Staff Proposal Into the Record and Providing for Comments Thereon," filed August 4, 2009.

[21] *See, e.g.,* the facts discussed in *Ass'n of Irritated Residents, et al. v. California Air Resources Board*, CGC 09-509526, Statement of Decision – Order Granting in Part Petition for Writ of Mandate, issued March 18, 2011 in Superior Court of California, County of San Francisco (reflecting possible delay in implementation of the GHG emissions regime).

impose. Consequently, the Commission determined it was appropriate to adopt the Final Staff Proposal's suggested cost pass-through. The Commission was concerned that any other approach could over or under compensate AB 1613 CHPs for their GHG compliance costs, and that this would not meet the "ratepayer indifference" requirements of AB 1613.

To cap the utilities' cost exposure, D.09-12-042 provided that the Buyer's GHG cost obligation would only be up to the emissions associated with operating the CHP facility at the CEC's minimum efficiency levels (CEC-based cap). D.09-12-042 required the CHP facility to be responsible for any additional GHG compliance obligation deriving from suboptimal operation of the facility.[22]

Given the transition of the AB 1613 program to one implemented pursuant to PURPA, it is now apparent that any compensation for GHG compliance costs must be consistent with avoided cost principles. Consequently, we hereby adopt an earlier proposal made by SDG&E/SoCal Gas that was considered, but rejected, in D.09-12-042.[23]

In comments responding to the Final Staff Proposal, SDG&E/SoCal Gas agreed that it was appropriate for the Buyer to pay for the GHG compliance costs associated with the excess energy sold to the utility. However, assuming adoption of the MPR-based pricing formula (which was adopted in D.09-12-042), SDG&E/SoCal Gas suggested that the cost pass-through be capped at the MPR heat rate so that the AB 1613 CHP operator would bear any GHG compliance costs for emissions associated with less efficient units. (SDG&E/SoCal Gas Opening Comments, filed August 24, 2009, at pp. 8-9.)

---

[22] D.09-12-042 at 48-49.

[23] See D.09-12-042 at 44.

In order to comply with avoided cost principles, the costs paid by the utility to the AB 1613 CHP should not exceed the avoided GHG compliance costs of the proxy CCGT the Commission has relied on to establish the avoided costs for energy. The SDG&E/SoCal Gas proposal, by setting a cap at the MPR heat rate, properly caps the costs that may be recovered by an AB 1613 CHP to the proxy CCGT's avoided GHG compliance costs. Adopting the cap will ensure that the price paid to AB 1613 CHPs for GHG compliance will not exceed the utilities' avoided cost. Consequently, the Commission adopts the SDG&E/SoCal Gas proposal and modifies D.09-12-042 accordingly.

Consistent with this determination, we clarify that if the AB 1613 CHP seller elects to have the utility procure GHG allowances for it, the utility's obligation to procure such allowances is capped at the number of allowances necessary to operate the proxy CCGT unit.

We recognize that traditionally an avoided cost payment incorporates all elements of energy production into a single payment, and here we have two components that comprise the avoided cost payment to an AB 1613 CHP – the MPR-based energy price, and the GHG compliance cost pass-through capped at the avoided cost of the CCGT proxy unit. Among other things, this cost pass-through approach may be administratively burdensome for the parties. However, given the uncertainty surrounding implementation of California's GHG compliance regime, this two component avoided cost approach is appropriate at this time. It allows for the program to comply with PURPA using a proposal already in the record of this proceeding (by ensuring that actual cost payments will not exceed the utility's avoided costs), and will allow AB 1613 CHP project development to move forward, resulting in the environmental benefits intended by AB 1613. While this payment scheme will apply to the life of contracts signed pursuant to the tariffs approved under this decision, the

Commission may revisit this issue as to future AB 1613 CHP contracts when the GHG allowance markets have evolved and compliance costs are more easily determined or forecasted.

**9. Contract Language Clean Up**

The Joint Utilities request in their Petition for Modification that certain language in the standard contracts adopted in D.09-12-042 be "cleaned-up" to correct internal inconsistencies. They claim that there are errors in the contracts, including references and defined terms that require clarification in order for the contracts to be administered. The Joint Utilities further claim that the requested modifications do not materially change the contracts or alter the intent of the D.09-12-042, but merely correct errors. The language the Joint Utilities propose to "clean-up" is shown in Attachment A to this decision.

TURN and DRA support the Joint Utilities proposed "clean-up" of contract language. FCE does not oppose most of Joint Utilities' proposed "clean-up" of the contract language but argues that some of the proposed "clean-up" would, in fact, alter the negotiated terms and intended meaning of the CHP contracts adopted by D.09-12-042. Similarly, CCDC is concerned that the Joint Utilities are unilaterally proposing changes to mutually agreed upon terms of the simplified AB 1613 contract without discussing them with CCDC first. CCDC does not object to legitimate "clean-up" changes but believes there are certain changes that would materially change agreed upon terms.

San Joaquin contends that these changes should not be addressed in a petition to modify but should be proposed through the compliance advice letter in which the Commission will give final approval to the AB 1613 contracts.

### 9.1. Discussion

The contracts adopted in D.09-12-042 primarily represent negotiated terms and conditions submitted by parties in this proceeding. When parties submitted these proposed contract terms and conditions, there were several issues left unresolved. In D.09-12-042, the Commission decided these unresolved issues.

Contract terms and conditions are critically important for successful contract execution. Where errors were made in drafting the final contracts, we agree with Joint Utilities that these errors should be fixed. However, based on parties' responses to the Petition, it appears that some of the contract "clean-up" proposed by Joint Utilities goes beyond merely fixing errors. Therefore, we adopt only those contract changes that do not materially change the contracts and changes that were not opposed by any other parties. Where there was disagreement among parties, the contracts shall remain as they were adopted in D.09-12-042.

On June 21, 2010, the IOUs filed advice letters implementing the standard contract and simplified contract adopted in D.09-12-042.[24] The IOUs shall file advice letters with updated tariffs reflecting revisions to the contracts adopted in this decision. Attachment A to this decision describes the proposed revisions requested by the Joint Utilities and provides the Commission's resolution for each proposal, whether they were adopted or rejected. The utilities are directed to modify the contracts in accordance to this table (in addition to making the changes to contract provisions discussed in other sections of this Decision).

---

[24] See PG&E Advice Letter 3696-E, SCE Advice Letter 2485-E, and SDG&E Advice Letter 2179-E.

Notwithstanding the above paragraphs, the IOUs are encouraged to work with individual CHP customers and developers to ensure the success of this program. Toward that end, if there are contract modifications that contracting parties can agree to, and which do not contravene the Commission's Orders, IOUs may work with CHP customers to make those modifications to the contracts before the contracts are submitted for final approval. For instance, we note that there is no clear definition of a repowered CHP facility included in the contract, an omission that IOUs and CHP customers may want to rectify. Another example would be using a clearer definition of "Eligible CHP Facility," as commented on by parties on the proposed decision. However, no filing-extensions will be granted for any such efforts.

**10. Line Loss Factor Calculation**

As part of the contract "clean-up," the Joint Utilities recommended changes to Exhibit C, Section 2 of the standard contract (Exhibit B, Section 2 of the simplified contract) including adding a loss factor to the time of delivery period payment calculation, to be consistent with D.09-12-042. The Amended Scoping Memo asked parties to respond to the following question regarding a line loss factor: What is an appropriate calculation for line losses associated with moving the CHP project's power from the Delivery Point to the grid controlled by the California Independent System Operator (CAISO)?

San Joaquin recommends using the distribution loss factors that apply to QFs that interconnect to the distribution system. CCDC and FCE agree with San Joaquin. However, PG&E and SCE disagree with this approach stating that distribution loss factors are outdated and the global QF Settlement requires each Seller to install a CAISO compliant meter that will automatically adjust payments for line loss. PG&E and SCE recommend that the Commission look to the QF Settlement for provisions on delivery requirements and line loss calculations, if any. SDG&E contends that line loss factors should be calculated for each individual project.

### 10.1. Discussion

As mentioned previously, the October 2010 proposed QF Settlement does not seek to modify any decision in this docket and does not apply to open matters in the scope of this proceeding. We will not pre-judge a proposed settlement pending in other open dockets. Additionally, the location adjustment factors defined in the QF Settlement refer to transmission losses, not distribution losses that are under consideration in this proceeding. For these reasons, we do not believe that use of the location adjustment calculation in the QF Settlement is the appropriate reference for line loss calculations under this AB 1613 program.

However, we are persuaded by arguments from PG&E and SCE that use of the distribution loss factors, as proposed by San Joaquin, are also not appropriate. As clarified by SCE, the intent of the "loss factor" was to compensate the purchasing utility for the actual losses associated with delivering power at the first point of connection with the utility's facilities rather than the CAISO grid. Furthermore, it is clear in D.09-12-042 that the Seller is responsible for line losses from the Delivery Point to the Interconnection Point.[25] Generation Meter Multipliers and distribution loss factors established through D.01-01-007 would compensate generators for avoided losses rather than the purchasing utility for actual line loss.

We conclude that these line losses are best calculated as part of a project's interconnection process, whether that be through CAISO, Rule 21 or another

---

[25] D.09-12-042, Attachment A, § 1.03 at 3.

interconnection process. While we understand the concern from CHP parties that this causes some uncertainty in project planning, because facilities participating in this program are small (under 20 MW) and will generally be serving local loads, we expect in most cases the line loss factor to be 1.0.

**11. Contract Option for Facilities Less than 500 Kilowatts**

In D.09-12-042, the Commission directed the parties to develop a streamlined contract for very small [less than 500 kilowatt (kW)] facilities within a set period of time. The Commission granted a request by the Joint Utilities to delay development of this contract until October 2010. Because of the delay in processing the two contracts approved in December 2009, and in light of the FERC Orders, the timing of this contract will also need to be updated.

The Amended Scoping Memo asked parities to respond to the following questions:

(1) What changes are required from the adopted contracts to make a less than 500 kW contract more streamlined?

(2) What changes, if any, are required in this contract to comply with the FERC Order?

CCDC, FCE, and SDG&E all list a number of contract provisions that can be streamlined for the under 500 kW contract option. PG&E suggests that interested parties meet to negotiate amendments to the streamlined contract to appropriately reflect the delivery potential and operating characteristics of facilities offering 500 kW or less of capacity. SCE points to the global QF Settlement and contends that the "very small" contract option is not necessary. SCE also raises a question regarding if the less than 500 kW refers to a facility's nameplate or exporting capacity. The Multijurisdictional Utilities argue that given their unique territories, the Commissions should not require them to adopt the very small contract.

### 11.1. Discussion

We will not address SCE's argument that the QF Settlement has replaced the need for a "very small contract," since, as previously mentioned, 1) we cannot pre-judge this as yet unapproved settlement, and 2) the settlement as proposed does not modify any item in this docket. SCE also seeks to clarify whether the 500 kW threshold that would be negotiated refers to nameplate or contract capacity. To clarify, consistent with the convention employed for both the contracts approved in D.09-12-042, this streamlined contract would be for facilities with a nameplate capacity less than 500 kW.

We agree with the proposal made by PG&E that the parties should work together to negotiate and propose a contract for this size point. Parties made several suggestions as to which items could be simplified to reach a contract appropriate for this size threshold. We suggest that prior to commencement of negotiations, Energy Division coordinate with the parties to host a workshop to develop a list of principles that would guide the development of the streamlined contract. Similar to the timeline considered in D.09-12-042, we expect that this contract would be developed within the next six months.

## 12. Additional Changes and Clarifications Required in Light of Subsequent FERC Orders

### 12.1. Overview

The FERC Declaratory Order states that the AB 1613 program is not preempted by the FPA or PURPA as long as: (1) the CHP generators from which the CPUC is requiring the Joint Utilities to purchase energy and capacity are QFs pursuant to PURPA; and (2) the rate established by the CPUC does not exceed the avoided cost of the purchasing utility."[26] Furthermore, FERC clarifies that "any ruling on the extent of federal preemption of the CPUC's AB 1613 program does not apply to public agency sellers that are exempt from Commission jurisdiction under section 201(f) of the FPA."[27]

In addition, the FERC Clarification Order supports a wide degree of latitude for the Commission to establish a utility's avoided cost; found that the concept of a multi-tiered avoided cost rate structure is consistent with the avoided cost requirements set forth in Section 210 of PURPA and FERC regulation; and recognizes that full avoided cost need not be the lowest possible avoided cost and can properly take into account real limitations on alternate sources of energy imposed by state law.[28]

The significance of the FERC's Clarification Order is that in contrast to its *Southern California Edison Company* decisions in the 1990s, where FERC required states to consider purchases from "all sources," including coal-fired generation, in setting avoided costs, the FERC's Clarification Order rules that all sources can be limited to those that are available to the utilities under state law.[29]

### 12.2. Amended Scoping Memo and Party Comments

In consideration of the FERC Declaratory Order, the Commission's September 2010 Amended Scoping Memo asked parties to comment on two QF-related questions:

---

[26] *California Public Utilities Commission et al.*, 132 FERC ¶ 61,047 at 67.

[27] *Id.* at 71.

[28] *California Public Utilities Commission et al.*, 133 FERC ¶ 61,059 at 26-30.

[29] *Id.* at 30.

1. What changes are necessary to the contracts approved under D.09-12-042 to reflect the requirement for QF certification in addition to the already mandated certification from California Energy Commission (CEC)?
2. If a QF already certified for and participating in the feed-in-tariff program loses its CEC certification under AB 1613 but maintains QF certification by FERC, what should the contract provide as the alternative rate for the QF (e.g., should the QF receive short run avoided cost pricing)?

Both SCE and PG&E commented generally that the Amended Scoping Memo failed to address the most critical question regarding how the Commission should set an avoided cost for the AB 1613 program consistent with PURPA. Both utilities recommended that the Commission take action to harmonize AB 1613 implementation with the Commission's other avoided cost proceedings.

As to the specific questions raised, several parties commented that the contract should be amended to ensure that the Seller is in compliance with QF requirements. PG&E suggested specific changes to the definition of "eligible CHP facility" to address this issue. Furthermore, CCDC and FCE point out that public entities need not obtain QF certification and any contract changes should make this clear. SCE suggests that all QFs, including the AB 1613 QFs, utilize the QF standard contract developed in accordance the global QF Settlement.

Regarding the event that a QF loses its AB 1613 certification, CCDC, San Joaquin, and FCE contend that the QF would be eligible for the applicable QF rate, namely Short Run Avoided Cost as developed in D.07-09-040. SDG&E and PG&E contend that in such a situation, the facility would be in default of a material term of the contract and no longer entitled to participate in the AB 1613 program.

### 12.3. The Record Reflects That The MPR-Based Price Is An Avoided Cost

While outside the scope of the Amended Scoping Memo, we respond first to the PG&E and SCE implication that the MPR-based priced adopted in D.09-12-042 is not an avoided cost and that the Commission must therefore calculate an avoided cost here.

It is true that the MPR-based price was adopted at a time when the Commission took the position that the AB 1613 CHP program was not subject to PURPA. However, this point is irrelevant. The legitimate question is not when the AB 1613 price was adopted, or under what circumstances, but whether or not the record demonstrates that the AB 1613 price is an appropriate avoided cost. Notwithstanding its belief when it issued D.09-12-042 that the AB 1613 program did not need to be implemented pursuant to PURPA, the Commission confined itself to an MPR-based price in order to comply with AB 1613's ratepayer indifference standards. As the Joint Utilities argued in their first rehearing application:

> By definition, "avoided cost" should be the measure of ratepayer indifference. That is, if ratepayers are simply paying the price they would have otherwise paid "but for" the AB 1613 purchase, they are indifferent to the existence of the AB 1613 tariff.[30]

We agree with the Joint Utilities. In D.09-12-042 we found that the MPR-based price, as a reasonable proxy for the generation the utilities would have purchased "but for" the AB 1613 purchase requirements, met the ratepayer

[30] Joint Utilities' Rehrg. App. January 20, 2010, at 12-13.

indifference standard of AB 1613. By the Joint Utilities' own definition, it is also a finding of avoided cost.

The MPR is intended to represent the long term market price of electricity for fixed price contracts.[31] The MPR is derived from the construction, operating and maintenance costs associated with a highly efficient 500 MW CCGT. The MPR inputs and methodology were developed pursuant to Public Utilities Code § 399.15(c) through a public process and the Commission relies on a public process to periodically update the MPR inputs and methodology.[32]

Based on this history of the MPR, and the fact that many of the pricing components of the MPR correspond to AB 1613's pricing requirements,[33] the Commission found in D.09-12-042 and affirmed in D.10-04-055 that the MPR's CCGT is the unit most likely to be procured by the utilities in the absence of the AB 1613 procurement obligation.[34] Because the Commission has found that a price based on the MPR's CCGT unit most closely approximates the costs avoided by procuring energy from AB 1613 CHPs, and the utilities have failed to present a reasonable argument that this is not the case, we find that the MPR-based price will not exceed the utilities' avoided costs and that the Joint Utilities' claim is without merit.

---

[31] Pub. Util. Code § 399.15(c)(1).

[32] *See, e.g.,* D.05-12-042; D.07-09-024; D.08-10-026; and the Commission's MPR website at http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr

[33] See Final Staff Proposal at 10.

[34] D.09-12-042 at 35; D.10-04-055 at 8-9.

### 12.4. QF Status and Two Tier Pricing Structure

In light of the FERC Declaratory Order, CHP facilities not exempt from FERC jurisdiction, which are participating in the AB 1613 feed-in-tariff program, must obtain QF status under PURPA requirements in order to be eligible for the avoided cost rates assigned by the Commission. The requirement to obtain QF status does not preclude the requirement for a CHP facility to also obtain certification from the CEC that it meets the higher efficiency standards as prescribed in AB 1613.

We agree with PG&E's suggested edits to the definition of "eligible facility" as applicable to address this issue. Specifically, we adopt the following change to the definition of "eligible facility" in the standard and simplified contracts for AB 1613:

> "Eligible CHP Facility" means a facility, as defined by Public Utilities Code Section 2840.2, subdivisions (a) and (b) that, (1) meets the guidelines established by the California Energy Commission pursuant to Public Utilities Code § 2843 and, (2) meets the requirements of 18 Code of Federal Regulations § 292.201, et seq., if applicable.

In the event that a facility is decertified by CEC, we agree with parties that this constitutes an event of default of the AB 1613 feed-in tariff rates under the contract. However, the CPUC cannot decertify a facility from its QF status; only the FERC can decertify a QF. If a facility were to fall below the minimum AB 1613 contract requirements, but still meet the requirements needed to retain its QF status, it would still be eligible to obtain a QF standard offer contract with a short-run avoided cost rate as ordered in D.07-09-040, if still in effect, or participate in any programs that supersede D.07-09-040. In no event may a utility unilaterally declare a default under the AB 1613 contract without the CEC decertifying the facility, just like a utility may not unilaterally declare a QF is in default under a QF contract without the FERC finding that the facility has lost its QF status. If the utility believes that a QF is not in compliance with federal standards, the utility may petition FERC to revoke the QF's status.[35]

In this regard, consistent with the "flexible pricing mechanisms," which the Ninth Circuit found were proper remedies for states[36] and the "multi-tiered avoided cost rates structure," which the FERC Clarification Order explained states may adopt for CHP generators,[37] we find that an AB 1613 compliant CHP facility is entitled to the AB 1613 pricing formula provided herein. However, in the event of decertification by the CEC, the contract should provide that the CHP generator should then be entitled to the established short-run avoided cost rate at the time of the CEC's decertification, and the utility should offer the CHP generator the standard offer contract associated with that rate. To the extent that the FERC were to revoke the QF status of the CHP generator, then the utility's obligation would be governed by the remedy provided at the time of the FERC's revocation of QF status. The utilities are directed to modify the AB 1613 contracts to be consistent with this discussion.

### 12.5. A PURPA Contract May Include Sanctions For Non-Compliance With State Efficiency Requirements

As described above, AB 1613 CHPs are to receive the MPR-based price so long as they comply with AB 1613. Should they fail to comply with AB 1613, but retain their QF status, they will receive payments pursuant to the most current short-run avoided cost. SCE objects to this two tier pricing structure. Citing

---

[35] *Independent Energy Producers Association, Inc. v. CPUC* (9th Cir. 1994) 36 F.3d 848, 859.

[36] *Id.*

[37] *California Public Utilities Commission*, 133 FERC ¶ 61,059 at 30.

*Independent Energy Producers Association v. CPUC* (9th Cir. 1994) 36 F.3d 848, 857-58, SCE argues that this two tiered price is unlawful "to the extent the Commission seeks to apply an 'alternative' avoided cost rate to AB 1613 QFs based simply on the CEC's higher efficiency standards for AB 1613 CHP."[38] We disagree. So long as the two prices in the two tier pricing structure do not exceed the utilities' avoided cost, and payment is based on contract compliance, SCE's claim has no merit.

The state may require higher efficiency from CHPs, and pay a lower avoided cost for failure to meet these requirements; such a program advances both state and federal goals to encourage efficient CHPs. Both PURPA and the Energy Policy Act of 2005 (EPAct 2005), like AB 1613, recognize CHPs as a special class of highly efficient facilities, with EPAct 2005 expressly directing FERC to consider revising its CHP criteria to ensure "continuing progress in the development of *efficient* electric energy generating technology."[39] Several courts have also acknowledged, with approval, the efficiency benefits of CHPs. In particular, the U.S. Supreme Court upheld FERC's decision to pay "full avoided costs" to CHPs and other small power producers as a development incentive to encourage fuel efficiency:

> … it was not unreasonable for the Commission to prescribe the maximum rate authorized by PURPA. The Commission's order makes clear that the Commission considered the relevant factors and deemed it most important at this time to provide the maximum incentive for the development of cogeneration and small power

---

[38] SCE Comments, September 29, 2010, at 5-6.

[39] See, e.g., 18 C.F.R. § 292.205 and 16 U.S.C. §824a-3(n)(1)(A)(iii) (emphasis added); see also Conf. Rep. No. 95-1750, pp. 97-98 (1978).

> production, in light of the Commission's judgment that the entire country will ultimately benefit from the increased development of these technologies and the resulting decrease in the Nation's dependence on fossil fuels. …The basic purpose of § 210 of PURPA was to increase the utilization of cogeneration and small power production facilities and to reduce reliance on fossil fuels.[40]

The Supreme Court in *American Paper* also recognized that "a qualifying facility and a utility may negotiate a contract setting a price that is lower than a full-avoided cost rate."[41]

Given the holdings of *American Paper*, SCE's reference to *Independent Energy Producers* as a barrier to the AB 1613 CHP two-tier payment structure is both inaccurate and inapposite here. *American Paper* clearly supports the two-tier payment structure we adopt here, and the holdings of *Independent Energy Producers* are irrelevant to the issue. *Independent Energy Producers* focused on QF status determinations, and whether a state could delegate QF status determinations to the utilities. It determined that only FERC could make a QF status determination, and thus the delegation was improper. In that context, the Court noted that a state could not sanction a QF for failure to meet *federal* QF efficiency standards. The QF status issues addressed by *Independent Energy Producers* are not at issue here; compliance with *state* law requirements is at issue. To the extent that a QF does not comply with *state* efficiency standards, that is up to the state to police and this is properly done through contracting requirements that provide sanctions for failure to comply.

---

40 *American Paper Inst. v. American Elec. Power* (*American Paper*) (1983) 461 U.S. 402, 417-418.

41 *Id.* at 416.

We recognize that, consistent with *Independent Energy Producers,* we may not revoke a facility's QF status, delegate that authority to a utility, or reduce the price paid to below avoided cost, and we do not attempt to do so here. To the extent that the price adjustment terms for failure to meet state efficiency requirements are reflected in the AB 1613 contract, and that both the high and low prices are avoided costs, it is a valid provision that meets both state and federal efficiency goals and the holdings in *Independent Energy Producers* do not preclude us from establishing such a structure.

### 12.6. The 10% Location Bonus Is Based On The Utilities' Avoided Costs

D.09-12-042 provides that an AB 1613 CHP located in a local resource adequacy area shall be paid a 10% location bonus calculated based on its total energy payment. The Joint Utilities have repeatedly argued that there is no basis for this 10% location bonus. The decision first denying rehearing on this issue, D.10-04-055, explained that the basis for the payment was the value of deferred transmission and distribution (T&D) upgrades, as well as the value of local grid stability and reliability:

> [D.09-12-042] determines that a 10% location bonus is appropriate in constrained areas because CHP sited in these areas would provide system benefits such as transmission and distribution upgrade deferrals and local grid stability and reliability.[42]

While D.10-04-055 cited to the record to generally support this conclusion, it did not explain the avoided cost basis for the 10% location bonus. In other words, there was no showing of utility avoided costs that justified the 10%

[42] D.10-04-055 at 10.

number. This is because the Commission at that time was not implementing the program pursuant to PURPA.

In light of the FERC orders, it is clear that D.09-12-042 must be clarified to explain the basis for the 10% location bonus adopted there. In summary, there is a record basis for the 10% location bonus, which was based on an "actual determination" of the utilities' avoided T&D costs. The 10% location bonus reflects extremely conservative assumptions that assures it will, in no event, exceed the utilities' avoided T&D costs. The discussion below shall be incorporated into D.09-12-042 to clarify the record and analysis on this issue.

#### 12.6.1.Record On The 10% Location Bonus

At the initiation of this rulemaking, the California Cogeneration Council (CCC) filed comments noting that the Commission currently uses a model to calculate average T&D avoided cost values for each utility's service area, by each utility division or planning region.[43] CCC provided, as Attachment A to its comments, a sample of the T&D avoided costs calculated for each utility by the model (CCC Attachment A). The spreadsheet model is commonly referred to as the "E3 Model" in the parties' comments. To calculate T&D avoided costs, the E3 Model relies upon each utility's marginal T&D costs adopted in their general rate cases.

Based on the avoided cost numbers reflected in Attachment A, CCC proposed to pay an avoided T&D cost "adder" to AB 1613 generators located in areas that would produce higher than average avoided cost benefits to ratepayers, but did not specifically identify the amount of the adder.[44] CCC

---

43 CCC Comments, July 31, 2008.

44 CCC Comments, July 31, 2008, at 10-14 and Attachment A.

proposed that the generators would cooperate with the utilities to identify the best areas to site such projects to generate the highest avoided costs. In making this proposal, CCC acknowledged that the utilities have traditionally argued against such a T&D avoided cost on the basis that such costs are "highly site-specific and that a case-by-case analysis is needed."[45] CCC noted that "to the CCC's knowledge, no CHP or renewable projects have ever been compensated for such locational benefits."[46]

In commenting on the CCC's proposal to identify T&D avoided costs, all three utilities agreed that distributed generation facilities have the potential to avoid T&D costs; however, each one argued that this proceeding was not the forum for quantifying those costs.[47] Among other things, they argued, as CCC anticipated, that each DG facility must be considered separately, on a case-by-case basis, to calculate such avoided costs. None of the utilities suggested that the E3 Model avoided cost calculations provided in the CCC Attachment A were inaccurate.

---

[45] CCC Comments, July 31, 2008, at pp.12-13.

[46] CCC Comments, July 31, 2008, at p. 13.

[47] See, e.g., SCE Comments, August 15, 2008, at 4 ("Thus, although SCE would agree that generation systems can be used to defer T&D investment, it is unlikely that this could or should be accomplished through enactment of this tariff.."); PG&E Comments, August 15, 2008, at 7 (PG&E "agrees that, in situations where CHP units truly allow a utility to avoid T&D costs, a benefit exists for its customers that would warrant paying an additional amount. However, as the Commission has previously determined, such 'right place, right time' situations may be fairly rare, and depend on a number of conditions being met for a T&D value to exist."); see also, SDG&E/SoCal Gas Comments, August 15, 2008, at 2 (outlining SDG&E's 4 criteria proposal for when a facility may qualify for T&D avoided costs, adopted in D.03-02-068).

On August 4, 2009, an Administrative Law Judge's ruling incorporated the Final Staff Proposal into the record of the proceeding and requested party comments on the proposal. The Final Staff Proposal suggested a 10% location bonus under both proposed pricing options for any eligible CHP located in a distribution or transmission constrained area. The Final Staff Proposal reasoned that CHP systems situated in constrained areas could provide system benefits such as transmission and distribution upgrade deferrals and local grid stability and reliability. The Final Staff Proposal asked parties to comment on how to determine location or distribution constrained areas for purposes of applying this bonus.

SCE and PG&E/TURN argued that the proposed location bonus of 10% was unsupported by analysis and unreasonable.[48] They also asserted that the "locational marginal price" (LMP) values in the CAISO market are the only accurate reflection of actual congestion and losses on the grid.[49] SCE also pointed out that adopting a generic location adder would be inconsistent with the generator-specific methodology adopted in D.03-02-068.[50]

SDG&E/SoCalGas contended that if certain facilities received a bonus because of their favorable location, then facilities located in less than favorable locations should receive less.[51] SDG&E/SoCalGas also contended that CHP located in its service territory is more valuable than CHP located elsewhere in

---

48 PG&E/TURN Comments, August 24, 2009, at 13; SCE Comments, filed August 24, 2009, at 12.

49 PG&E/TURN Comments, August 24, 2009, at p.13; SCE Comments, filed August 24, 2009, at p. 14.

50 SCE Comments, August 24, 2009, at 12-14.

51 SDG&E/SoCalGas Comments, August 24, 2009, at 6.

the CAISO-controlled grid given the need for local resources in their service territory. They argued that locational value should only be provided to CHP located in areas with local resource adequacy requirements when contracting with the local utility.[52]

CCDC and FCE supported the Final Staff Proposal's location bonus. CCDC and FCE suggested that the location bonus should be provided to any location where the CAISO nodal LMP exceeds the zonal price.[53]

#### 12.6.2. Analysis of the 10% Location Bonus

Historically, the Commission has agreed with the utilities that while distributed generation facilities unquestionably generate avoided T&D costs, a facility-specific analysis was required before a T&D avoided cost could be paid to generators. The Commission has therefore previously declined to adopt a uniform avoided cost calculation for T&D. Instead, D.03-02-068, issued February, 2003, established four facility-specific criteria to be met for a facility to qualify for avoided T&D costs. To our knowledge, which is consistent with CCC's, no facility has ever qualified for T&D avoided costs under this test.

Notwithstanding the determinations in D.03-02-068, the Commission's position on this matter has evolved over the last eight years in other proceedings so that today the E3 Model is used to calculate avoided T&D costs to determine the cost effectiveness of the utilities' energy efficiency and demand response

---

52 SDG&E/SoCalGas Comments, August 24, 2009, at 6.

53 CCDC Comments, filed August 24, 2009, at 9; FCE Comments, filed August 24, 2009, at 9.

programs.[54] The utilities benefit from the inclusion of uniform avoided T&D costs in these programs. The more cost-effective the program, because of the addition of T&D avoided costs, the more money utility shareholders may receive in the form of performance incentives.

We previously found merit to SDG&E/SoCal Gas's contention that a location bonus is appropriate for generators located in areas with local resource adequacy (RA) requirements. As a result, we adopted a 10% location bonus for eligible CHP systems located in CAISO-identified location-constrained resource areas, which the Commission identifies as Local RA areas for purposes of establishing local RA procurement requirements.[55]

The Local RA program, approved in D.06-06-064, is intended to ensure that the utilities have acquired sufficient generation capacity to serve defined, transmission constrained local areas. Each year the Commission adopts Local RA requirements and identifies Local RA areas based on the CAISO's annual study of local capacity requirements.[56] The CAISO study identifies the specific substations included in each Local RA area – constrained areas that require the purchase of a specified amount of Local RA resources to avoid T&D system failures.

---

[54] The E3 Model for calculating avoided costs for energy efficiency was adopted in D.05-04-024 and updated in 2008 to apply to the utilities' 2009-2011 energy efficiency portfolio plans. (Assigned Commissioner's and Administrative Law Judge's Ruling, R.06-04-010, April 21, 2008.) These updates did not include changes to the methodology for calculating avoided T&D.

[55] D.09-12-042 at 38-39.

[56] The CAISO's 2008 Local Capacity Requirement (LCR) Study is available from the CAISO website, http://www.caiso.com/1c44/1c44bbc954950.html

In D.09-12-042, we determined that eligible CHP interconnected within any of the identified Local RA areas should receive the location bonus. We required each utility to make these location bonus areas, including the specific substations included in each area, publicly available on its website. This information is required to be updated each year upon adoption by this Commission of the Local RA program requirements.[57] The location bonus is to be applied for the entirety of an AB 1613 CHP's contract term based on the Local RA areas identified in the year the contract is executed.

To the extent that parties believe that the 10% location bonus does not reflect avoided cost, or will push the MPR-based price above avoided cost, they are wrong. As an initial matter, it should be noted that all of the utilities agree that distributed generation, which includes AB 1613 CHPs, results in avoided T&D investment. Nevertheless, the 10% location bonus will only be made available to new AB 1613 facilities constructed in Local RA areas. AB 1613 CHPs located in these Local RA areas will generate avoided costs to the utilities well above the 10% location bonus the utilities will pay them.

CCC Attachment A sets forth utility-specific avoided T&D costs by geographic "divisions" which average $5.60/MWh for PG&E's service area, $6.66/MWh for SCE's service area, and $13.03/MWh for SDG&E's service area, assuming a baseload profile, which is the profile of an AB 1613 generator. Based on these average avoided costs for T&D, a 10% location bonus paid to CHP facilities located in Local RA areas for avoided T&D investment is a conservative estimate of the actual T&D costs avoided in Local RA areas for several reasons.

---

[57] 2010 Resource Adequacy program requirements were adopted by this Commission in D.09-06-028.

First, the 10% location bonus is only paid on the amount of energy sold to the utility, and not on the amount of energy that the utility avoids producing due to the existence of the AB 1613 generator. Thus, the AB 1613 CHP will receive a payment for far less than the T&D costs it actually avoids. For example, when a utility achieves 10 MWh in energy efficiency savings, it gets credit for 10 MWh of avoided T&D costs, measured by the E3 Model and reflected in the CCC Attachment A. However, if an AB 1613 generator generates 10 MWh of energy, but only sells 1 MWh to the utility, while it avoids 10 MWh of generation, and thus, produces savings similar to 10 MWh of energy efficiency, the AB 1613 generator is only paid the 10% location bonus on the 1 MWh sold to the utility. Pursuant to AB 1613, generators must size output to load and may only sell their excess power to the utility. Thus, any payment to an AB 1613 generator for avoided T&D costs will be less than actual T&D costs avoided.

Second, the CCC Attachment A averages calculated from the data provided in the E3 model are based on avoided T&D investment in the *entire* utility service area. The 10% adder will only be paid to generators located in Local RA areas, which are the most constrained resource areas and will therefore have the highest avoided T&D costs. For example, CCC Attachment A shows that avoided T&D costs are as high as $9.17/MWh in PG&E's service area, $8.33 in SCE's service area, and $13.03 in SDG&E's service area. In that regard, the 10% Location Bonus based upon "average" T&D costs is a conservative estimate of the cost actually avoided by the utility for T&D. Further, the avoided T&D costs reflected in CCC Attachment A are likely to increase as a result of utility filings for increases in transmission rates at FERC, and increases in distribution rates in Commission proceedings.

In adopting the 10% location bonus for AB 1613 generators located in local RA areas, the Commission recognizes that it must be consistent with federal law.

The *FERC Clarification Order* explained that if the adder is based on an actual determination of expected costs of T&D upgrades it would constitute an avoided cost determination and be consistent with PURPA and Commission regulations:

> [I]f the CPUC bases the avoided cost "adder" or "bonus" on an actual determination of the expected costs of upgrades to the distribution or transmission system that the QFs will permit the purchasing utility to avoid, such an "adder" or "bonus" would constitute an actual avoided cost determination and would be consistent with PURPA and our regulations.[58]

Further, the Commission has a great deal of discretion in determining this expected avoided cost. As the Ninth Circuit Court of Appeals recognized in *Independent Energy Producers*, the Commission has broad authority to implement Section 210 of PURPA, "states play the primary role in calculating avoided costs," and states have "a great deal of flexibility … in the manner in which avoided costs are estimated …"[59] FERC recently affirmed and further clarified these principles in its *Clarification Order*. There, it emphasized the fact-specific nature of avoided cost determinations and its reluctance to "second guess" state determinations:

> As the Commission has previously explained, "states are allowed a wide degree of latitude in establishing an implementation plan for section 210 of PURPA, as long as such plans are consistent with our regulations. Similarly, with regard to review and enforcement of avoided cost determinations under such implementation plans, we have said that our role is generally limited to ensuring that the plans are

---

58 133 FERC ¶ 61,059 at 31.

59 *Independent Energy Producers Association, supra,* 36 F.3d 848, 856.

> consistent with section 210 of PURPA…." [*See American REF-FUEL Company of Hempstead*, 47 FERC ¶ 61,161, at 61,533 (1989); *Signal Shasta*, 41 FERC ¶ 61,120 at 61,295; *see also LG&E Westmoreland Hopewell*, 62 FERC ¶ 61,098, at 61,712 (1993).] In this regard, the determinations that a state commission makes to implement the rate provisions of section 210 of PURPA are by their nature fact-specific and include consideration of many factors, and we are reluctant to second guess the state commission's determinations; our regulations thus provide state commissions with guidelines on factors to be taken into account, "to the extent practicable," [18 C.F.R. § 292.304(e) (2010)] in determining a utility's avoided cost of acquiring the next unit of generation.[60]

The U.S. Supreme Court's holdings in *American Paper* further support the Commission's determination to adopt a uniform T&D avoided cost in the form of the 10% location bonus, instead of requiring the project-specific determination of prior years. In that case, the Supreme Court found that FERC appropriately adopted a uniform rule that every CHP was entitled to full avoided cost payments. Among other things, the Supreme Court referred to PURPA's legislative history stating that such rate determinations should not be subject to the same level of scrutiny typically applied to utility rate applications. The Supreme Court quoted that legislative history at length, including the directive to encourage CHPs:

> "[C]ogeneration is to be encouraged under this section and therefore the examination of the level of rates which should apply to the purchase by the utility of the cogenerator's or small power producer's power should not be burdened by the same examination as are utility rate

[60] 133 FERC ¶ 61,059 at 24.

> applications, but rather in a less burdensome manner. The establishment of utility type regulation over them would act as a significant disincentive to firms interested in cogeneration and small power production."[61]

The Supreme Court examined FERC's policy reasons for adopting the full avoided cost rule, instead of a generator-specific avoided cost. Among them, the Supreme Court recognized FERC's desire to provide development incentives, and that such development would serve the public interest:

> The Commission recognized that the full-avoided-cost rule would not directly provide any rate savings to electric utility consumers, but deemed it more important that the rule could "provide a significant incentive for a higher growth rate" of cogeneration and small power production, and that "these ratepayers and the nation as a whole will benefit from the decreased reliance on scarce fossil fuels, such as oil and gas, and the more efficient use of energy." [footnote omitted] 45 Fed. Reg. 12222 (1980).[62]

The Supreme Court properly noted that "[t]he Commission would have encountered considerable difficulty had it attempted to determine an appropriate rate less than full avoided cost."[63] Similarly here, the Commission's project-specific T&D adder has proven to be unworkable. To encourage CHP consistent with both federal and state law, the Commission adopts a uniform rule here to compensate AB 1613 CHPs located in Local RA areas for some portion of the T&D costs they allow the utility to avoid. Such a uniform rule is

---

[61] *American Paper, supra,* at 414, quoting from H. R. Conf. Rep. No. 95-1750, pp. 97-98 (1978).

[62] *Id.* at 415.

[63] *Id.* at 416.

consistent with both FERC orders, and the Supreme Court's holdings in *American Paper*.

In summary, the 10% location bonus the Commission adopted in D.09-12-042 is consistent with FERC's regulations because it is based on an "actual determination" of the utilities expected T&D costs, as established in their general rate cases and incorporated into the E3 Model relied on here. Based on these costs, and as explained above, the 10% location bonus is a conservative under-estimate of the avoided T&D costs associated with AB 1613 generators situated in location constrained resource areas and will not result in AB 1613 generators receiving more than avoided costs for their energy sales to the utilities.

**13. Comments on Proposed Decision**

The proposed decision of the Assigned Commissioner in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on December 6, 2010 by FCE, DRA, TURN, CCDC, SDG&E, and jointly by PG&E and SCE. Reply comments were flied on December 13, 2010 by San Joaquin, FCE, DRA, CCDC, and jointly by PG&E and SCE. In this section we address the major issues addressed by the parties.

The Joint Utilities have argued in their comments to the proposed decision that the price offered under this program is not reflective of avoided costs. The Commission has previously found, in D.09-12-042 and D.10-04-055, that a combined cycle gas turbine is a reasonable proxy for the marginal unit avoided by an eligible CHP facility under this program and that the MPR-based price is reflective of this proxy.[64] The AB 1613 price also includes a location bonus for AB 1613 CHPs located in Local RA areas. Commission staff had estimated the avoided costs to be approximately 10% of the sales to the utility to the extent the AB 1613 CHP avoids congestion and the potential cost of upgrading transmission and distribution facilities. Other parties supported this estimate as we noted in D.10-04-055.[65] We recognize that these are estimates of the avoided costs, because each of the utilities have filed for further increases in transmission rate cases at FERC and for higher distribution rates in Commission proceedings. Therefore, some of the avoided costs of further upgraded distribution and transmission facilities may be higher. Nevertheless, the Commission has determined that there is a need to have a legal obligation upfront to encourage CHP facilities to locate in constrained areas, consistent with AB 1613 and PURPA. Accordingly, this 10% location bonus is a reasonable and conservative estimate of the avoided costs of the upgraded facilities.

Nevertheless, we recognize the value in further clarifying our positions on these issues, and we do so here in Sections 7 and 12.

With respect to determining the price paid to Sellers who choose to procure their own GHG allowances by utilizing a publically available index, CCDC suggests that the Commission modify the Proposed Decision to provide that Energy Division shall determine the appropriate index with input from stakeholders. We agree that such input would help to ensure the index is credible and publicly available.

---

[64] See, for example, D.09-12-042 at 35.

[65] See D.10-04-055 at 10.

## 14. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Amy Yip-Kikugawa is the assigned Administrative Law Judge in this proceeding.

## Findings of Fact

1. D.09-12-042 established a feed-in-tariff price and approved a standard AB 1613 contract for use by all eligible CHP systems up to 20 MW.

2. D.09-12-042 approved a simplified AB 1613 contract for use by CHP systems that export no more than 5 MW.

3. The pricing formula adopted by D.09-12-042 is based on the costs associated with a proxy natural gas generation resource. Several inputs into the pricing formula come from the MPR, established in accordance with Pub. Util. Code § 399.15.

4. The Energy Division updates the cost inputs and recalculates the MPR annually.

5. The AB 1613 pricing formula adopted by D.09-12-042 included four inputs from the 2008 MPR, including a Fixed Component, Variable Operations and Maintenance, Heat Rate, and Time of Delivery periods and factors.

6. The 2008 MPR was the most current calculation available when the Commission issued D.09-12-042.

7. The fixed price component of the contract price does not escalate during the entire term of the contract.

8. The fixed price component is based on the year in which a project is expected to come online.

9. The "Term Start Date" is the date that the project starts, not the year in which the contract is signed.

10. The fixed component of the MPR, upon which AB 1613 pricing was based, does not include a GHG adder. GHG compliance costs in the MPR calculation are embedded in the variable component of the MPR.

11. GHG compliance costs are not being paid for twice but the adopted contract language created ambiguity.

12. The fixed components of the MPR do not include a GHG adder and GHG compliance costs are not reflected in any way in the adopted pricing formula. Therefore, no additional subtraction is necessary to ensure compliance costs are not paid for twice.

13. The arguments raised by the Joint Utilities to reduce the AB 1613 price to reflect pricing for an as-available product were considered and rejected by the Commission in D.09-12-042 and D.10-04-055. The Joint Utilities do not raise any new issues of law or fact in their petition for modification related to the issue of whether AB 1613 pricing should be reduced to reflect pricing for an as-available product.

14. Sellers that are already obligated to comply with GHG regulations may be better suited to procure allowances for emissions associated with their exported electricity because it is a function they will already be performing for emissions associated with their heat needs and on-site electricity consumption.

15. D.09-12-042 established that GHG compliance costs should be paid for by the Buyer.

16. The AB 1613 contracts are primarily the result of negotiated terms and conditions submitted by the working group and parties to this proceeding.

17. The AB 1613 form contracts adopted by D.09-12-042 contain some drafting errors that create internal inconsistencies.

18. Some of the "clean-up" proposed by the Joint Utilities goes beyond correcting drafting errors.

19. Because facilities participating in the AB 1613 program are small (under 20 MW) and will generally be serving local loads, we expect in most cases the line loss factor to be one.

20. The FERC Declaratory Order found that the AB 1613 program is not preempted by the FPA or PURPA as long as: (1) the CHP generators from which the CPUC is requiring the Joint Utilities to purchase energy and capacity are QFs pursuant to PURPA; and (2) the rate established by the CPUC does not exceed the avoided cost of the purchasing utility.

21. The record of this proceeding reflects that the MPR-based AB 1613 price is an avoided cost price, notwithstanding the fact that the price was adopted prior to the FERC Declaratory Order and FERC Clarification Order.

22. The FERC Declaratory Order states that any ruling on the extent of federal preemption of the CPUC's AB 1613 program does not apply to public agency Sellers that are exempt from Commission jurisdiction under Section 201(f) of the FPA.

**Conclusions of Law**

1. The AB 1613 program implemented by D.09-12-042 should be modified where necessary to comply with PURPA and avoided cost principles.

2. It is reasonable to use the most up-to-date price inputs in the pricing formula for the AB 1613 contract.

3. Since the MPR is updated annually, it is reasonable to use the inputs from the most current MPR in the pricing formula.

4. Neither CCDC nor San Joaquin provided a sufficient basis to make use of the most current MPR contingent upon a de minimus change in the total MPR value.

5. As long as the MPR is calculated based on the costs of a proxy natural gas generation resource, it is reasonable to use the MPR components in the AB 1613.

6. Updated pricing inputs should only apply prospectively to new contracts executed after the effective date of this decision. The pricing for executed contracts should be based on the pricing inputs at the time the contract was executed and for the life of the contract.

7. The language added by D.09-12-042 to Exhibit C, Section 3 of the standard contract and to Exhibit B, Section 3 of the simplified contract should be modified to state that the fixed price component does not escalate during the term of the contract.

8. The fixed price component should be based on the year in which a project is expected to come online, which is synonymous with the "Term Start Date," rather than the year in which the contract is signed.

9. The language of Section 3 of Exhibit C to the standard contract and Section 3 of Exhibit B to the simplified contract should be amended to read, "The Fixed Price Component, FPC, for all TOD Periods shall be the amount in the following table for the year of the Term Start Date."

10. The language adopted in Table 2 of D.09-12-042 should be clarified to reflect the Commission's intent that GHG compliance costs are not being paid for twice.

11. Because Joint Utilities provided no new authority or facts for the Commission to consider reducing the feed-in tariff price to reflect that CHP resources are as-available, this proposed modification should be denied. However, modifications should be made to D.09-12-042 consistent with the discussions in Sections 7 and 12 herein to provide clarity on this point.

12. Modifications should be made to D.09-12-042 or to the form contracts to allow the Sellers have the option to purchase GHG allowances for GHG

compliance or to have the utilities procure the allowances on behalf of the Sellers. The contracts should allow the Seller the option to either elect to manage its own allowances and request payment from the utilities or to have the utility purchase allowances for the emissions associated with the excess electricity purchased by the utility.

13. Modifications should be made to D.09-12-042 and the form contracts to cap GHG compliance cost reimbursements to the sellers at the cost to procure such allowances for the proxy CCGT unit. If the seller elects to have the utility procure GHG allowances for it, modifications should be made to D.09-12-042 and the form contracts to cap the utility's obligation to procure GHG allowances to the number of allowances necessary to operate the proxy CCGT unit.

14. If the Sellers choose to purchase allowances, the payment should be tied to the most recent public index price, identified by Energy Division with input from stakeholders.

15. Contract language which is in error or which creates internal inconsistencies should be modified to correct such errors as set forth in Attachment A.

16. Contract language should be updated to ensure that facilities obtain Qualifying Facility status from the FERC.

17. Modifications requested by the Joint Utilities that materially change the contracts or alter the intent of D.09-12-042 should be denied.

18. Because the form contracts adopted by D.09-12-042 represent negotiated terms and conditions submitted by parties to this proceeding, they should not be modified where there is disagreement among parties.

19. Line losses for the AB 1613 program are best calculated as part of a project's interconnection process.

20. All California IOUs must file amended tariffs to reflect the revisions adopted in this decision.

21. The changes to the form contracts shown in Attachment A of this decision should be implemented in the contracts filed by each utility.

22. The FERC Clarification Order supports a wide degree of latitude for the Commission to establish a utility's avoided cost rates and finds that the concept of a multi-tiered avoided cost rate structure is consistent with the avoided cost requirements set forth in Section 210 of PURPA and FERC regulation.

23. The FERC Clarification Order recognizes that full avoided cost need not be the lowest possible avoided cost and can properly take into account real limitations on alternate sources of energy imposed by state law.

24. D.09-12-042 should be clarified to reflect the avoided cost basis for the 10% location bonus.

25. D.09-12-042 should be clarified to reflect the avoided cost basis for the MPR-based price.

26. D.09-12-042 should be modified to cap GHG compliance cost reimbursements to the AB 1613 CHP sellers at the avoided costs of the MPR's CCGT proxy unit.

**O R D E R**

**IT IS ORDERED** that:

1. The petition to modify of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company is granted in part with modifications and denied in part, as set forth the Ordering Paragraphs below.

2. Inputs from the most recently adopted Market Price Referent must be used in the pricing formula for the Assembly Bill 1613 standard and simplified

contracts, as long as the Market Price Referent is calculated based on the costs of a proxy natural gas generation resource. Only new contracts executed after the effective date of this decision are impacted by updated pricing inputs. The pricing for executed contracts continues to be based on the pricing inputs in the contract at the time the contract was executed and for the life of the contract.

3. Each year, upon adoption by this Commission, of a new Market Price Referent calculation, each California investor-owned utility must file a Tier-1 Advice Letter updating its Assembly Bill 1613 tariffs and standard contracts with the new Market Price Referent inputs. The advice letters must be filed and served within five days of the date that the order adopting the Market Price Referent is mailed. This advice letter must also include a summary table of information about resources procured as a result of this program in the previous year and over the life of the program and updates on Location Bonus areas. Energy Division staff will provide the utilities with a template for the information to be provided in this table prior to the end of the program's first implementation year.

4. The California investor-owned utilities must revise the standard and streamlined contracts to reflect the fact that, when entering into the contract, the Combined Heat and Power Seller can (1) elect to manage its own allowances (and request payment from the California investor-owned utilities according to the terms outlined in this reimbursement methodology) <u>or</u> (2) elect to have the California investor-owned utility purchase allowances for the emissions associated with their electricity exports. Energy Division staff must determine an appropriate publically available index for use in determining the price to be paid for the allowances after seeking input from stakeholders by January 31, 2012. Energy Division will make this information available to stakeholders in an appropriate manner. The contracts shall also reflect that any reimbursement to

generators for greenhouse gas compliance costs shall be capped at the compliance costs of the Market Price Referent's proxy unit.

5. Modified contract language for the contracts approved by Decision 09-12-042, as set forth in Attachment A to this decision is adopted. Attachment A also shows modifications we reject in this order. The approved changes must be implemented in the contracts filed by each California investor-owned utility.

6. The California investor-owned utilities must revise the standard and streamlined contracts to reflect that line losses from the Delivery Point to the Interconnection Point are determined as part of the interconnection process.

7. The California investor-owned utilities must revise the standard and streamlined contracts to reflect that in the case that a facility is decertified from participating in the Assembly Bill 1613 program, the combined heat and power generator should still be provided with the established short-run avoided cost rate at the time of decertification and the utility should offer the combined heat and power generator the standard offer contract associated with that rate unless the Federal Energy Regulatory Commission were to revoke the Qualifying Facility status of the facility.

8. D.09-12-042 shall be modified as follows:

   a. The title of the decision is modified to be: "DECISION ADOPTING POLICIES AND PROCEDURES FOR PURCHASE OF EXCESS ELECTRICITY PURSUANT TO CALIFORNIA ASSEMBLY BILL 1613 AND THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978."

   b. The discussion at Section 1 "Summary" on page 1 is replaced with the discussion at Section 1 "Summary" in the Conformed Version of D.09-12-042, attached as Attachment B to the decision disposing of the applications for rehearing of D.10-12-055 (Rehearing Order for D. 10-12-055).

c. The discussion at Sections 3.1 “Commission Authority to Establish AB 1613 Purchase Price” through 3.2.2 “Discussion” at pages 6 to 17 is replaced with the discussion in Sections 3.1 “Commission Authority to Establish AB 1613 Purchase Price” through 3.3.2 “Discussion” in the Conformed Version of D.09-12-042, attached to the Rehearing Order for D. 10-12-055 as Attachment B.

d. A new footnote is added to the end of the second sentence in the first full paragraph on page 13 that starts “Irrigation Districts assert that the definition….” The footnote reads:

“Unless otherwise noted, all further section references are to the California Public Utilities Code.”

e. Section 3.3 “Benefiting Customers” is renumbered 3.4 and Sections 3.3.1 “Parties’ Positions” and 3.3.2 “Discussion” are renumbered 3.4.1 and 3.4.2 respectively.

f. Consistent with D.10-04-055, OP 2 “e” through “h”, the discussion starting at the top of page 23 with “This determination is supported by prior Commission decisions” is replaced with the discussion at pages 17 through 18 of the Conformed Version of D.09-12-042, attached to the Rehearing Order for D.10-12-055 as Attachment B, which begins with “All customers will benefit as a result ….” and ends just before Section 3.5 “Program Cap”.

g. Section 3.4 “Program Cap” is renumbered 3.5 and Sections 3.4.1 “Parties’ Positions” and 3.4.2 “Discussion” are renumbered 3.5.1 and 3.5.2 respectively.

h. The last sentence in the partial paragraph at the top of page 32 is modified to read:

“They further assert that failing to link actual fuel input costs with the price paid under the tariff could create operational problems for CHP and potentially result in grid reliability problems.”

i. The discussions at Sections 4.4 “Location Bonus” and 4.5 “Discussion” at pages 33 to 39 are replaced with the discussions in Sections 4.4 "Location Bonus" through 4.5.5 "Adopted Price Formula" in the Conformed Version of D.09-12-042, attached to the Rehearing Order for D. 10-12-055 as Attachment B.

j. A new footnote is added to the end of the only paragraph in Section 5 "Contract Terms and Conditions" on page 40. The footnote reads:

   "The Conformed Version of D.09-12-042 does not modify these Attachments."

k. A new footnote is added to the end of the first partial paragraph at the top of page 42. The footnote reads:

   "D.10-12-055 reset this 6-month deadline so that the advice letter deadline is now June 17, 2011."

l. The discussions at Section 5.3.2.1 "Allocation of GHG Compliance Costs" and Section 5.3.2.2 "GHG Reductions and Benefits" at pages 45 to 50 is replaced with the discussions in Section 5.3.2.1 "GHG Compliance Costs" and Section 5.3.2.2 "GHG Reductions and Benefits" in the Conformed Version of D.09-12-042, attached to the Rehearing Order for D. 10-12-055 as Attachment B.

m. The first sentence of the first full paragraph on page 50 that starts "As mentioned in Section 3.2.2 and the discussion above," is modified to read:

   "As mentioned in the discussion above, several parties argue that the contract price should be even higher to reflect the value of other green attributes."

n. Section 5.6 "Indemnity" at page 54 is replaced with Section 5.6 "Indemnity" in the Conformed Version of D.09-12-042, attached to the Rehearing Order for D. 10-12-055 as Attachment B.

o. A new footnote is added to the end of the last sentence of the partial paragraph at the top of page 55 that reads "As previously discussed, the CEC issued its draft guidelines on October 1, 2009." The footnote reads:

"In February 2010, the CEC released the final guidelines for certification of CHP systems pursuant to AB 1613 and in June 2010 the CEC released its final statement of reason relevant to these guidelines."

p. The discussions at Section 5.7 "Eligible CHP Facility Status" and Section 5.8 "Qualifying Facility Status" pages 54 to 56 are replaced with the discussions in Section 5.7 "Eligible CHP Facility Status" and Section 5.8 "Qualifying Facility Status And Two Tier Price Structure" in the Conformed Version of D.09-12-042, attached to the Rehearing Order for D. 10-12-055 as Attachment B.

q. A sentence is added before the last sentence in the first full paragraph on page 59. The last sentence starts: "Accordingly, we retain contract terms 3.01 and 3.02 …" The additional sentence added before that sentence reads:

"This is also consistent with Pub. Util. Code § 2841(f), which provides that the generating capacity of the AB 1613 CHP will count towards the resource adequacy requirements of the utility."

r. A sentence is added at the end of the last paragraph on page 67. It reads:

"PURPA requires that the price paid to AB 1613 generators be no more than the utilities' avoided costs. This program meets all of these requirements."

s. The discussions at Section 7 "Conclusion" and Section 8 "Comments on Proposed Decision" at pages 68 to 71 are replaced with the discussions in Section 7 "Conclusion" and Section 8 "Comments on Proposed Decision" in the Conformed Version of D.09-12-042, attached to the Rehearing Order for D. 10-12-055 as Attachment B.

t. The Findings of Fact, Conclusions of Law, and Ordering Paragraphs set forth at pages 72 to 83 are modified as set forth in the Findings of Fact, Conclusions of Law, and Ordering Paragraphs in the Conformed Version of D.09-12-042, attached to the Rehearing Order for D. 10-12-055 as Attachment B.

9. Within 45 days of the date this order is mailed, Pacific Gas and Electric Company shall file a supplemental advice letter to update Advice Letter 3696-E. The advice letter must include revised tariff sheets to implement the standard contract and the simplified contract adopted in Decision 09-12-042 as modified by Attachments A of this decision and other Ordering Paragraphs. The tariff sheets shall become effective on filing subject to Energy Division determining that they are in compliance with this order.

10. Within 45 days of the date this order is mailed, Southern California Edison Company shall file a supplemental advice letter to update Advice Letter 2485-E. The advice letter must include revised tariff sheets to implement the standard contract and the simplified contract adopted in Decision 09-12-042 as modified by Attachments A of this decision and other Ordering Paragraphs. The tariff sheets shall become effective on filing subject to Energy Division determining that they are in compliance with this order.

11. Within 45 days of the date this order is mailed, San Diego Gas & Electric Company shall file a supplemental advice letter to update Advice Letter 2179-E. The advice letter must include revised tariff sheets to implement the standard contract and the simplified contract adopted in Decision 09-12-042, as modified by Attachments A of this decision and other Ordering Paragraphs. The tariff sheets shall become effective on filing subject to Energy Division determining that they are in compliance with this order.

12. Consistent with Decision (D.) 09-12-042 and any approved extensions granted by the Commission, within six months of the date this order is mailed,

Sierra Pacific Power Corp. and PacifiCorp must file an advice letter in compliance with General Order 96-B. The advice letter must include tariff sheets to implement either:

a. the simplified contract approved by D.09-12-042 as modified herein (Attachment A) with proposed modifications to account for their location outside of the California Independent System Operator-controlled grid, or

b. a proposed simplified contract for eligible combined heat and power systems less than 500 kilowatts, as discussed in D.09-12-042, Ordering Paragraph 6 by to October 18, 2010.

13. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company must negotiate with the parties to develop a simplified contract for less than 500 kilowatt hour systems; if desired, Energy Division will host a workshop to establish guiding principles.

14. All changes proposed by Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company that would materially alter the contracts adopted in Decision 09-12-042 are denied.

15. Rulemaking 08-06-024 remains open to address the "pay-as-you-save" program.[66]

This order is effective today.

Date December 16, 2010, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN

66 Implementation of a "pay-as-you-save" program was addressed in D.11-01-010 and this proceeding was closed pursuant to that decision.

TIMOTHY ALAN SIMON
NANCY E. RYAN
Commissioners

Peevey Attachment A