Date of Issuance: May 14, 2012

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ENERGY DIVISION **RESOLUTION E-4475**
May 10, 2012

R E S O L U T I O N

Resolution E-4475. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) submit data to revise the Market Price Benchmark (MPB) to include a Renewable Portfolio Standard (RPS) Adder, in accordance with Decision (D.) 11-12-018 issued in the Direct Access (DA) Rulemaking 07-05-025.

PROPOSED OUTCOME: Pursuant to Ordering Paragraph (OP) 5 of D.11-12-018, this Resolution adopts the **input for the Renewable Portfolio Standard (RPS) adder** for 2011 and 2012 to reflect the market value of RPS-compliant resources in the cost responsibility assigned to departing customers necessary to maintain bundled customer indifference.

ESTIMATED COST: No impact on utilities' authorized revenue requirements.

By PG&E Advice Letter (AL) 3987-E, SCE AL 2688-E, and SDG&E AL 2325-E Filed on January 6, 2012.

SUMMARY

This Resolution implements the method adopted in D.11-12-018 to account for the market value of RPS-compliant resources in the charges related to departing load.

Departing load is load associated with customers that have left utility bundled service to take service from non-utility providers such as Direct Access (DA) Electric Service Providers (ESPs) or Community Choice Aggregators (CCAs).

D.11-12-018 adopted a revised method for computing departing load charges that takes into account both the cost and the market value of RPS-compliant resources and directed the Energy Division to prepare a resolution calculating inputs to the revised RPS adder.

BACKGROUND

Departing load charges adopted by the Commission are designed to keep bundled utility customers financially indifferent to departing load.

The Commission has prescribed various departing load charges to ensure that bundled customers are financially indifferent to departing load. Under Commission rules, departing customers need to pay departing load charges when electric generation costs incurred by the utility in the past exceed the current market price, resulting in above-market cost obligations for the utilities.

The Power Charge Indifference Adjustment (PCIA) is imposed to ensure that customers departed from bundled utility procurement service remain responsible for paying any utility costs incurred on their behalf. This protects remaining bundled customers from any cost shifting and leaves them financially indifferent as a result of customers departing utility bundled service.

To derive the indifference amount, the market value of the utility's supply portfolio is subtracted from the total portfolio cost. The market price benchmark (MPB) is a calculated proxy which represents the market value of the utility's total energy resource portfolio. The utility total portfolio includes utility-owned generation, purchased power, DWR contracts, fuel costs, and California Independent System Operator (CAISO) costs. A positive indifference amount indicates that the utility portfolio cost is above-market for that year. The indifference amount is recovered from departed customers through a non-bypassable surcharge to maintain bundled utility customer indifference.

The utilities' above-market costs are determined by comparing the utilities' portfolio cost to the Market Price Benchmark (MPB), previously adopted in D.06-07-030. The utilities' above-market costs are used to compute the PCIA and the Competition Transition Charge (CTC) and are reflected in the Transitional Bundled Service (TBS) Rate.

The departing load charges fall into three main categories:

a. The Power Charge Indifference Adjustment (PCIA): The PCIA recovers departing customers' share of costs of potentially stranded resources.

b. The Ongoing Competition Transition Charge (CTC): The CTC recovers the uneconomic cost of QF power contracts initiated prior to 1995.

c. The Transitional Bundled Service (TBS) Rate: The TBS Rate is the energy price applicable to customers temporarily on bundled service while switching electric providers so that the utility can adjust its generation portfolio without cost impacts on bundled customers.

The Commission in D.11-12-018 adopted a revised method to calculate departing load charges so that they reflect both the cost and the value of required RPS-compliant power purchases.

The current indifference methodology to calculate the PCIA, the CTC, the TBS and the MPB only recognizes the utilities' cost of renewable resources in the calculation of the Total Portfolio Cost and does not account for the market value of renewable resources in the MPB. The non-inclusion of the separate value for the RPS was not an issue earlier, because renewables were a small part of the resource mix. However, as the percentage of renewables in the utilities' portfolios is increasing under the new RPS requirements, it is necessary to account for the value of the RPS-compliant resources in the MPB.

D.11-12-018 determined that an adjustment to the MPB to account for the market value of renewable resources will result in a more accurate measure of indifference costs.

By ignoring the value of RPS-compliant resources, the MPB understates the value of utility resources and overstates the utilities' above-market costs. Therefore, D.11-12-018 revised the MPB calculations to incorporate an RPS adder to reflect the increasing requirement to purchase RPS-compliant power.

The method adopted in D.11-12-018 to develop the RPS adder is based partly on the average energy cost of utility RPS-compliant resources.

In order to produce a more broad-based weighting of the RPS adder, the Commission decided in D.11-12-018 to make use of sources of RPS cost data that incorporate transactions of other load serving entities besides the utilities. The methodology adopted in this decision uses a weighted average method of 68%/32%, with 68% representing the average cost of the three utilities' RPS-compliant resources and 32% representing the average premium paid for renewable energy contracts in the Western United States, based on data compiled by the U.S. Department of Energy (DOE). This weighting corresponds to the percentage of the total load subject to RPS requirements currently represented by utility load. The applicable percentages are subject to updated data in subsequent years.

D.11-12-018 directed each utility to file an advice letter providing the following information:

A. Most recent 12 months figures derived from US Department of Energy survey of Western US renewable energy premiums in calculating a weighted proxy for the Market Price Benchmark compiled by the National Renewable Energy Laboratory [DOE data]; and

B. All RPS-compliant resources that are used to serve utility customers during the current year (i.e., most recent 12 months) and those projected to serve customers during the next year, including both contracts and utility-owned resources, including the projected costs together with the net qualifying capacity of energy produced by each of these resources (relevant costs in dollars and volumes in megawatt-hours [MWh] and qualifying capacity in kilowatts [kW]).

The utilities filed advice letters to implement the RPS adder method.

Pursuant to OP 4 of D.11-12-018, on January 6, 2012, PG&E filed AL 3987-E; SCE filed AL 2688-E; and SDG&E filed AL 2325-E, designated as Tier 2. On January 12, 2012, PG&E submitted substitute sheets to correct an error in a formula so that it sums all pertinent lines. The utilities in their ALs provided the relevant data necessary to reflect RPS-compliant resources in the MPB, in accordance with OP 4 of D.11-12-018, namely: Most recent 12 months figures derived from US Department of Energy survey of Western US renewable energy premiums in calculating a weighted proxy for the Market Price Benchmark compiled by the National Renewable Energy Laboratory [DOE data]; and

A. All RPS-compliant resources that are used to serve utility customers during the current year (i.e., most recent 12 months) and those projected to serve customers during the next year, including both contracts and utility-owned resources, including the projected costs together with the net qualifying capacity of energy produced by each of these resources (relevant costs in dollars and volumes in [megawatt-hours] MWh and qualifying capacity in [kilowatts] kW).[1]

NOTICE

Notice of PG&E AL 3987-E, SCE AL 2688-E, and SDG&E AL 2325-E was made by publication in the Commission's Daily Calendar. PG&E, SCE, and SDG&E state that a copy of the Advice Letter was mailed and distributed in accordance with Section 3.14 of General Order 96-B, including to parties on the service list for Rulemaking 07-05-025, the proceeding in which D.11-12-018 was issued.

PROTESTS

Energy Division received one Late-Filed Protest from the Alliance for Retail Energy Markets, the Direct Access Customer Coalition, the Marin Energy Authority, and the City and County of San Francisco (Joint Protestors) to PG&E Advice Letter 3987-E; SCE Advice Letter 2688-E; and SDG&E Advice Letter 2325-E.

In their protest dated February 8, 2012, the Joint Protestors offer their proposed formula to calculate the Market Price Benchmark per D.11-12-018.

SCE and SDG&E responded to the protest of the Joint Protestors on February 15, 2012, and PG&E responded on February 17, 2012.

[1] The utilities provided RPS-compliant resource cost data in the confidential version of this filing, and redacted in the public version. OP 4 of D.11-12-018 provides that confidential data will be protected from public disclosure.

SCE and PG&E support the formula proposed by the Joint Protestors, except that they argue that the capacity value should reflect monthly Net Qualifying Capacity and shaped capacity values.

SCE agrees with the formula suggested by the Joint Protestors, "with one exception: the Resource Adequacy (RA) capacity adder calculation for purposes of both the RPS adder and the MPB should be done on a monthly basis. In its RA adder proposal submitted in both the Direct Access Rulemaking Phase 3 proceeding as well as the workshops that preceded the evidentiary hearings, SCE utilized a proposed annual capacity value which was "shaped" to produce monthly values and monthly net qualifying capacity (NQC) measures for generation resources in the portfolio. The NQC and capacity value data submitted by SCE in Advice 2688-E for purposes of calculating the RPS adder are provided on a monthly basis, and SCE would intend that the RA adder determined for purposes of the MPB would also reflect monthly NQC and capacity values."

SDG&E agrees with the formula as written.

SDG&E is indifferent whether this calculation should be done on a monthly or annual basis.

The utilities and Joint Protestors agree that due to the varying proportions of RPS-compliant resources, the MPB will vary by vintage.

The Commission in D.08-09-012 refined the method for determining departing customers' cost responsibility for new generation resources to vary depending on when the customers depart and which new generation resources were committed to on their behalf prior to their departure. The utilities agree with the Joint Protestors that the revised methodology adopted in D.11-12-018 will result in MPBs that vary by vintage year. Further, unless the Commission directs the utilities to provide more information to the Energy Division regarding the vintaged portfolios, the utilities will have the responsibility for determining the vintaged MPB.

DISCUSSION

D.11-12-018 did not adopt a method for determining capacity value using shaped capacity values.[2] Therefore, we will not use SCE's method.

SCE converted the annual RA capacity adder adopted in D.11-12-018 to monthly values based on shaping factors provided by SCE in the Phase III proceeding. Thus SCE provided both monthly NQC by resource and the shaped (monthly) capacity value so that Energy Division could sum NQCs across all resources by month, and then multiply those monthly NQC totals by the shaped capacity values to produce a monthly capacity value for all resources. Summing those monthly totals gives the annual capacity value for the entire portfolio of resources. This annual capacity value would be subtracted from the total cost of the portfolio of RPS-compliant resources to give just the "energy" cost of the renewable resources.

Besides SCE's proposal to use shaped capacity values, two other options exist to calculate the capacity value, which is to be subtracted from the total cost of the portfolio of RPS-compliant resources. One is to calculate a simple average NQC for the year by summing the monthly NQCs and dividing by 12, then multiplying the result by $50.17/kW-year (the CEC's most recent estimate of the going forward costs of a combustion turbine that D.11-12-018 adopted as the RA capacity value). The other is to multiply the highest (or summer peak) NQC by $50.17/kW-year.

Using the latter approach and applying the $50.17/kW-year capacity value to the system peak month's NQC for each resource, by valuing the capacity at the highest NQC, would potentially overstate the total capacity value of those RPS resources. Using the peak month value could also completely miss picking up any capacity value of resources coming online after the peak month. Thus the simple average is preferable, because while the value of some resources may be overstated, the value of others might be understated, and on average, any such inaccuracies would offset each other.

[2] See OP 8 of D.11-12-018 and discussion at p. 32.

The Joint Protestors in their late-filed protest proposed a formula, which is attached to this resolution also as Exhibit A. The formulas set forth in Exhibit A accurately represent the principles adopted in D.11-12-018. Therefore, we adopt it for use on an ongoing basis for developing the MPB.

The Formula proposed by the Joint Protestors to calculate the Market Price Benchmark is adopted per D.11-12-018.

The Joint Protestors in their late-filed protest proposed a formula, which is attached to this resolution as Exhibit A. The formulas set forth in Exhibit A accurately represent the principles adopted in D.11-12-018. Therefore, we adopt it for use on an ongoing basis for developing the MPB. Regarding the comments at the end of the exhibit about the MPB computation process, we provide the following specific guidance.

- To incorporate the RPS adder into the MPB, on October 1 of each year, each utility is to file an AL, pursuant to OP 5 of D.11-12-018, to update their data, since, per OP 5, "The applicable percentage weightings [32% DOE Data and 68% utility data] are subject to relevant updated data in subsequent years." In subsequent years, these advice letters may be designated as Tier 1, and any confidential data shall be protected from public disclosure, as provided in OP 4 of D.11-12-018.
- For receipt by early November of each year, Energy Division purchases from Platt's (or another appropriate source) daily trading prices for the calendar month of October - both for on-peak and off-peak periods for both North and South of Path 15. Using this data together with the shaping factors adopted in D.11-12-018, Energy Division will perform the **MPB calculation as adopted in D.06-07-030** and compare its results with each utility's own calculation.
- Using the confidential data provided by the utilities in their October 1 ALs on their RPS-compliant resources, **the Energy Division calculates the average energy cost of the utilities' RPS-compliant resources** to incorporate into the MPB as adopted in D.11-12-018.
- **Each utility then uses Energy Division's results in its Energy Resource Recovery Account (ERRA)** application to compute specific MPBs by vintage and the applicable departing load cost responsibility surcharges.

Table 1 shows the development of the utility cost data input to the RPS adder for 2011 and 2012 derived from the data submitted by the utilities in their advice letters.

The Energy Division performed the steps as specified in D.11-12-018. First, Energy Division summed the costs for all the RPS-compliant resources of all three utilities for 2011 and 2012. See the line identified as "Resource Cost" in Table 1. From this overall cost, the value of NQC is subtracted. The resulting energy cost net of NQC is divided by the MWh of energy. The resulting average of utility RPS-compliant energy costs, Utility $/MWh, is shown on the final line of Table 1. The $/MWh are identified in the protest of the Joint Protestors as the "URGgreen" RPS Adder. See Table 1. This is the utility data that is weighted 68% in the ultimate RPS Adder.

Table 1

Statewide 2011 - "URGgreen" for RPS Adder	
Resource Cost	$1,000,291,215
NQC Cost	$38,943,303
Cost net NQC	$961,347,912
MWh	10,548,897
Utility $/MWh	$91.13

Statewide 2012 - "URGgreen" for RPS Adder	
Resource Cost	$1,029,338,990
NQC Cost	$21,767,946
Cost net NQC	$1,007,571,044
MWh	8,884,714
Utility $/MWh	$113.41

As Adopted in D.11-12-018, the value of capacity (NQC Cost on Table 1) will be computed as the current Resource Adequacy (RA) capacity adder times the total annual average net qualifying capacity (NQC) of RPS-compliant resources.

To determine the value of RPS-compliant resources for use in the MPB, the Commission adopted an approach that relies partly on the cost of the utilities' RPS-compliant resources. OP 5 of D.11-12-018 states in relevant part, "The Energy Division will calculate the average cost of power from the IOU [utility] resources by summing up all the costs from all three IOUs, subtracting the product of the NQCs of those resources times the IOU's current RA capacity adder used in the Market Price Referent, and dividing by the sum of all the MWHs from all three IOUs."

Therefore, the capacity value (NQC Cost in Table 1) will be determined by applying the simple average NQC for the year (by summing the monthly NQCs and dividing by 12) to the adopted RA value (currently $50.17/kW-year).

COMMENTS

Public Utilities Code section 311(g)(1) provides that this resolution must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. Accordingly, on April 6, 2012, the draft of this resolution was mailed to parties for comments. On April 26, 2012, the following parties submitted comments on Draft Resolution (DR) E-4475:

- The Alliance for Retail Energy Markets, City and County of San Francisco, City of Cerritos, Commercial Energy, Direct Access Customer Coalition, Marin Energy Authority, Retail Energy Supply Association, and School Project for Utility Rate Reduction (collectively, **Joint Parties**);
- Southern California Edison Company (SCE) and
- San Diego Gas & Electric Company (SDG&E).

This section explains the limited changes we made to the draft resolution (DR) as a result of the issues addressed in comments.

Table 1[3] reflects the correction SDG&E submitted to its RPS-compliant resource cost data originally provided to the Energy Division.
Subsequent to issuance of DR E-4475, SDG&E became aware that its original submittal included all RPS contracts that delivered energy in years 2011 and 2012, rather than RPS contracts that started deliveries in those years as adopted in D.11-12-018. SDG&E in its comments explained that "While this correction to the data narrows the definition of the contracts to be included and thus decreases the numbers of contracts that are included, these contracts are generally higher priced as they are the most recent contracts signed." Table 1 is revised to reflect this correction.[4]

[3] The table titles are altered in response to SCE's concern raised in its comments that the input adopted in this resolution as shown on Table 1 is a total value (of utility RPS-compliant resource costs), rather than an increment (the RPS Adder itself).

[4] The revised values for "Utility $/MWh" shown on the bottom line of Table 1 are nearly 5% higher for 2011 and nearly 9% higher for 2012.

SDG&E and SCE[5] should File Tier 1 Advice Letters with Tariffs showing departing load charges for 2011 that are compliant with the methods adopted in D.11-12-018.

To insure implementation without added delay, the Joint Parties in their comments request that the Commission in this resolution require the utilities to submit a Tier 2 Advice Letter within 10 days of the effective date of the final Resolution and also require the utilities to implement the revised charges and Accompanying Refunds by a firm date.

SCE in its comments states that DR E-4475 lacks an order to file tariffs in compliance with the (new) methods adopted in D.11-12-018. SCE explained that "Because the new methodology will change rates [sic], SCE must secure the Commission's approval. With no order, under General Order 96-B, SCE would file a Tier 2 advice letter and await Commission approval before implementing the new [charges]."

A Tier 1 advice filing would enable SCE and SDG&E to proceed with refunds to customers responsible for the 2011 DL charges, because an unprotested Tier 1 advice letter filing is effective when filed. Both SCE and the Joint Parties point out that affected customers have been waiting more than a year for this matter to be resolved and to receive a refund of their over-payments of departing load Charges as directed in D.11-12-018. The Joint Parties also stress the inequity of DA customers not being able to receive their share of SCE's refund of $441 million in California Department of Water Resources operating reserves. While bundled customers receive their share of this refund through an energy credit, DA customers are to receive their share by a credit through the PCIA. Thus, the Joint Parties argue that SCE's DA customers will be unable to receive their DWR refund until SCE implements revisions to its PCIA.

D.11-12-018, together with the April 14 and 22, 2011 Rulings in Rulemaking 07-05-025 and D.11-12-031 in PG&E's ERRA Proceeding, provide sufficient guidance about implementing the departing load charges using the revised method. With regard to the timing of over-charges to be refunded to affected

[5] PG&E is governed by Ops 5, 6, and 7 of D.11-12-031 in PG&E's 2012 Energy Resource Recovery Account (ERRA) and 2012 Generation Non-Bypassable Charges Forecasts Proceeding.

customers, we will require that rebilling of affected customers begin within 60 days of the effective date of the next scheduled rate change.

Therefore, within 14 days of the date of this resolution, SCE and SDG&E shall file Tier 1 advice letters with tariffs to implement the Ongoing CTC, the PCIA, and the TBS Rate based on the revised method with their 2011 cost forecasts. These advice letters shall include workpapers showing underlying computations to support the rate tables.

D.11-12-018 did not adopt a method for determining capacity value using shaped capacity values. Therefore, we will not use SCE's method.

In its comments, SCE reargued its position, which was addressed fully in DR E-4475. We only add references in the discussion section of this resolution to the specific language in that decision.

The language in D.11-12-018 (at p. 30) SCE cited in its comments adopts use of the CEC CT but not monthly capacity numbers. Note the use of the article "the [underline added in the quote below] before "Net Qualifying Capacity of all generation resources in the utility portfolio".
"Accordingly, we shall adopt SCE's proposal to update the RA capacity adder using the California Energy Commission's estimates of the going forward costs of a combustion turbine, which is updated biannually, including the Net Qualifying Capacity of all generation resources in the utility portfolio."

Likewise, OP 8 of D.11-12-018 says, "the Net Qualifying Capacity of the utility electric supply portfolio," not "the shaped Net Qualifying Capacity of the utility electric supply portfolio.

FINDINGS AND CONCLUSIONS

1. Commission Decision 11-12-018 directed PG&E, SCE, and SDG&E to file Tier 2 Advice Letters to identify the relevant data necessary to revise the non-bypassable cost responsibility surcharges to reflect RPS-compliant purchases.
2. The Alliance for Retail Energy Markets, the Direct Access Customer Coalition, the Marin Energy Authority, and the City and County of San Francisco (Joint Protestors) submitted a Late-Filed Protest to PG&E AL 3987-E, SCE AL 2688-E, and SDG&E AL 2325-E. Each of the utilities responded to the protest of the Joint Protestors.

3. Decision 11-12-018 did not adopt a method involving shaped capacity values. Thus, the shaped capacity value method recommended by SCE should not be used.
4. The Joint Protestors in their protest proposed a formula to calculate the Market Price Benchmark per Decision 11-12-018.
5. The formula set forth by the Joint Protestors in Exhibit A accurately represents the principles adopted in Decision 11-12-018, and thus it is reasonable for the Commission to adopt this formula.
6. D.11-12-018, together with the April 14 and 22, 2011 Rulings in Rulemaking 07-05-025 and D.11-12-031 in PG&E's Energy Resource Recovery Account Proceeding, provide sufficient guidance about implementing the departing load charges using the revised method.

THEREFORE IT IS ORDERED THAT:

1. The utility data inputs to the Renewable Portfolio Standard Adders for 2011 and 2012 calculated by Energy Division using the information provided by PG&E in AL 3987-E, SCE in AL 2688-E, and by SDG&E in AL 2325-E are adopted as shown on Table 1.
2. The value of capacity to be subtracted from the total cost of the portfolio of Renewable Portfolio Standard-compliant resources will be computed as the adopted Resource Adequacy capacity value of $50.17 (subject to updates in future years) times the average of each utility's monthly net qualifying capacity of RPS-compliant resources.
3. The Formula to Calculate the Market Price Benchmark per D.11-12-018 is adopted as shown in the Joint Protestors' Exhibit A attached to this Resolution.
4. By October 1 of each year, PG&E, SCE, and SDG&E shall file Tier 1 advice letters to update the data specified in Ordering Paragraph 4 of Decision 11-12-018 and shown in the Background Section of this Resolution, so that the applicable percentage weightings (32% for Department of Energy data and 68% for utility data) are updated in subsequent years. Any confidential data shall be protected from public disclosure.
5. Each utility shall use the Renewable Portfolio Standard Adder inputs shown on Table 1 in its Energy Resource Recovery Account application to compute specific Market Price Benchmarks by vintage and the applicable departing load charges.

6. Rebilling of affected customers must begin within 60 days of the effective date of each utility's next scheduled rate change. Therefore, within 14 days of the date of this resolution, SCE and SDG&E shall file Tier 1 advice letters with tariffs to implement the Ongoing CTC, the PCIA, and the TBS Rate based on the revised method with their 2011 cost forecasts. These advice letters shall include workpapers showing underlying computations to support the rate tables.
7. Protests and comments are denied except to the extent granted by the preceding Ordering Paragraphs.

This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held in Fresno on May 10, 2012; the following Commissioners voting favorably thereon:

/s/PAUL CLANON
PAUL CLANON
Executive Director

MICHAEL R. PEEVEY
President
TIMOTHY ALAN SIMON
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
Commissioners

Exhibit A

Proposed Formula to Calculate the Market Price Benchmark per D.11-12-018

Revised MPB for year *n* and Vintage Total Portfolio v= { (1-RPS%$_V$) x BROWN + (RPS% $_V$) x GREEN + CAP ADDER $_V$} x (LOSSES)
n = year covered by the calculation, e.g. n=2012 for the MPB for 2012.
v = PCIA vintage year
RPS% = The fraction of RPS compliant electric energy in the URG [Utility Resource Generation] Total Portfolio[6] for PCIA Vintage year *v* in year *n*.

BROWN = Weighted average of peak and off-peak forward prices for year *n*, weighting based on, for each IOU, the IOU bundled load profile data for the most recent year that is publicly available. Peak and off-peak forward prices based on published data for NP15/SP15 as per D.06-07-030. ($/MWh)

GREEN = 0.68 x URGgreen + 0.32 x (BROWN + DOEadder)
Where:
URGgreen = {[Forecasted cost in year *n* of RPS power contracts and IOU-owned projects starting deliveries in year *n* and *n-1*] - [NQC[7] of those contracts/projects*CAP VALUE]}/[Total forecasted deliveries from those contracts in year *n*] ($/MWh)
The forecasted cost of all Renewable Energy Credit (REC)-only contracts will also include the cost of energy associated with those REC-only contracts, equal to BROWN x forecasted deliveries from those REC-only contracts in year *n*.

DOEadder = Simple average of the premiums of the renewable programs in states within Western Electricity Coordinating Council (WECC), as identified in the database compiled by the National Renewable Energy Laboratory for the US Department of Energy. If multiple premiums are identified for the same utility and/or program, all shall be included in the average. ($/MWh)

---

[6] Per D.07-07-030 and D.08-09-012

[7] Net Qualifying Capacity

CAP ADDER = {Sum of NQC for all resources in the URG Total Portfolio for PCIA Vintage year *v* * CAP VALUE)/forecast of the sum of MWh supplied by URG Total Portfolio for PCIA Vintage year *v*}

CAP VALUE = the going forward cost (sum of insurance, ad valorem and fixed operations and maintenance costs) of a combustion turbine as determined per the most recent California Energy Commission (CEC) *Comparative Costs of California Central Station Electricity Generation Report*[8] for a small simple cycle merchant plant.

Per Table 4 of 2010 CEC report,

Insurance:	$9.63 per kW-year
Ad Valorem:	$13.09 per kW-year
Fixed O&M:	$27.45 per kW-year
Total Going Forward Costs (CAP VALUE):	$50.17 per kW-year

LOSSES = Line loss factors per D.07-01-030: PG&E 1.06; SCE 1.053; SDG&E 1.043

The Energy Division would calculate the **BROWN** and **GREEN** elements to the formula, based on inputs provided by each IOU. The IOUs would calculate the Market Price Benchmarks for each Vintage, based upon the **GREEN** and **BROWN** values provided by Energy Division, the **CAP VALUE** above, and the RPS percentages, NQCs and energy of each URG Total Portfolio. These calculations would be provided to Energy Division for verification.

[8] http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF