Decision **PROPOSED DECISION OF ALJ FUKUTOME** **(Mailed 7/22/2008)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 06-02-013 (Filed February 16, 2006)

(See Appendix A for a list of appearances.)

DECISION ON NON-BYPASSABLE CHARGES FOR NEW WORLD GENERATION AND RELATED ISSUES

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DECISION ON NON-BYPASSABLE CHARGES FOR NEW WORLD GENERATION AND RELATED ISSUES

1. Summary

By this decision, we implement new generation[1] non-bypassable charges (NBCs) previously established by Decision (D.) 04-12-048 and D.06-07-029. The applicability and form of these charges are determined for customers of the investor-owned utilities (IOUs)[2] that choose direct access (DA)[3] service or the services of a community choice aggregator (CCA),[4] as well as municipal departing load (MDL)[5] and customer generation departing load (CGDL)[6] customers. Among other things, this decision:

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[1] New generation includes generation from both fossil fueled and renewable resources contracted for or constructed by the investor-owned utilities subsequent to January 1, 2003.

[2] Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE).

[3] DA load customers purchase electricity from an independent electric service provider (ESP) and receive transmission and distribution service from the IOU.

[4] CCAs are governmental entities formed by cities and counties to serve the energy requirements of their local residents and businesses. The IOU continues to provide transmission and distribution service.

[5] Departing load (DL) generally refers to retail customers who were formerly IOU customers but now receive energy, transmission and distribution services from publicly owned utilities, self-generation or other means. MDL refers to DL served by a "publicly owned utility" (POU) as that term is defined in Public Utilities Code Section 9604(d), including municipalities or irrigation districts. There are two categories of MDL: transferred MDL and new MDL. Transferred MDL is load that was served by an IOU on or after December 20, 1995, and subsequently departed to be served by a POU. (Resolution E-4064, p. 1, fn. 1.) MDL also includes new MDL, which is load that has never been served by an IOU but is located in an area that had previously been in the

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1. Determines that once departed from bundled service, MDL (with the exception of large municipalizations) and CGDL will not have to pay the new generation related NBCs because, by procuring resources based on LTPP forecasts that exclude CGDL and MDL classes, the IOU will not have incurred costs on behalf of these customers.

2. Determines that for large municipalizations whose loads are included in the adopted load forecasts, the Commission will address the cost responsibility for payment of the new generation related NBCs through an application process.

3. Determines that the new generation NBC authorized by D.04-12-048 should be implemented as a component of the cost responsibility surcharge (CRS).[7] The revised CRS shall be calculated on the following bases:

(*footnote continued from previous page*)

IOU's service territory (as that territory existed on February 1, 2001) and was annexed or otherwise expanded into by a POU." (Resolution E-4064, p. 1, fn.1.)

[6] The term "Customer Generation" refers to cogeneration, renewable technologies, or any other type of generation that (a) is dedicated wholly or in part to serve a specific customer's load; and (b) relies on non-utility or dedicated utility distribution wires rather than the utility grid, to serve the customer, the customer's affiliates and/or tenant's, and/or not more than two other persons or corporations.

[7] The other components include the ongoing competition transition charge (ongoing CTC), and Department of Water Resources (DWR) power and bond charges. For PG&E, DA and non-exempt MDL are responsible for the Energy Charge Recovery Amount (ECRA), formerly the regulatory asset charge, which recovers PG&E's bankruptcy-related costs pursuant to D.03-12-035. This charge was included as an element to be collected from CRS in D.04-02-062. Pursuant to D.04-11-015, the ECRA superseded and replaced the regulatory asset charge on March 1, 2005. For SCE, DA and DL were responsible for the historical procurement charge (HPC), which recovers

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- With a few exceptions, use of a total portfolio approach that accounts for the ongoing CTC, DWR power charges and D.04-12-048 charges.[8] This includes netting the individually calculated annual charges and carrying over any negative total charge to offset positive charges in subsequent years. Further, we determine that pre-restructuring resources[9] should continue to be included in the portfolio of resources used in determining any ongoing CTC and D.04-12-048 charges, once cost recovery of the DWR contracts ends. Finally, we will address the effects of the 10-year limitation on cost recovery of new non-renewable portfolio standard (RPS) generation resources on bundled customer indifference, on a case-by-case basis, if and when the IOUs request cost recovery extensions, pursuant to the provisions of D.04-12-048.
- Use of the market benchmark adopted in D.06-07-030, as modified by D.07-01-030, to determine above-market costs.
- Use of a vintaging methodology based on the calendar year in which customers depart and on whether they depart in the first or second half of the calendar year.

(*footnote continued from previous page*)

costs from a settlement of the filed rate case in federal court. SCE has fully recovered this charge, and the HPC is no longer being collected.

[8] Public Utilities Code Section 367(a) sets forth the method for the calculation of the ongoing CTC. Also, in some situations, there will be departing load customers who do not pay the DWR power charges, and thus, the total portfolio method (indifference calculation) is not applicable in calculating ongoing CTC. (*See* D.07-01-020, p. 5 & D.06-07-030, pp. 35-38; *see* also D.05-01-035, p. 3.) (Order modifying Resolution E-3831 and denying rehearing of Resolution, as modified.)

[9] For purposes of this decision, "pre-restructuring resources" refers to those current IOU resources that existed prior to March 31, 1998 and are not subject to ongoing CTC treatment. These resources consist principally of the IOUs' retained generation (i.e., hydro, coal and nuclear plants). Power from these resources tends to be cheaper when compared to the costs related to ongoing CTC, the DWR contracts and new generation.

2. Background

Track 3 of Phase II of this proceeding was established in March 2007 to separately address NBCs and related issues. Specifically, Track 3 and this decision pertain to the applicability and implementation of new generation related NBCs that were established in D.04-12-048 and D.06-07-029. New generation resources are subject to either the D.04-12-048 NBC or the D.06-07-029 NBC.

By D.04-12-048, the IOUs are allowed to recover the uneconomic or stranded costs related to new generation resources from departing customers. By D.06-07-029, the IOUs are allowed to recover new generation power purchase agreement (PPA) net costs of capacity (total cost less revenues achieved through an energy auction process) from all benefitting customers in the IOUs' service territories. Customers subject to the D.06-07-029 NBC would be allocated resource adequacy (RA) credits for use in satisfying certain Commission RA requirements. The utility will identify new generation PPAs for which it elects to use the D.06-07-029 cost allocation methodology at the time it files an application for approval of the PPAs.

Subsequent to the establishment of Track 3, the majority of implementation issues related to the NBC established by D.06-07-029 have been resolved by D.07-09-044. That decision adopted an uncontested settlement that specified the principles for the D.06-07-029 energy auction and the implementation details for the corresponding allocation of benefits and costs.

A prehearing conference for Track 3 was held on July 12, 2007. Evidentiary hearings were held September 17 through September 21, 2007. Opening Briefs were filed on October 31, 2007. Reply briefs were filed on

November 15, 2007, at which time this track of the proceeding was submitted for decision.

Testimony on NBC and related issues was prepared by each of the following parties:

PG&E
SCE
SDG&E
Alliance for Retail Energy Markets (AReM)
California Clean DG Coalition (CCDC)
California Municipal Utilities Association (CMUA)
Cogeneration Association of California (CAC) and Energy Producers and Users Coalition (EPUC), jointly
Hercules Municipal Utility (Hercules)
Merced Irrigation District (Merced ID)
Modesto Irrigation District (Modesto ID)
The Utility Reform Network (TURN)
Western Power Trading Forum (WPTF)

Each of the parties, with the exception of WPTF and CAC, filed opening briefs.[10] In addition, the Division of Ratepayer Advocates (DRA), the City and County of San Francisco (CCSF) and the South San Joaquin Irrigation District (SSJID) each filed opening briefs. Reply briefs were filed by PG&E, SCE, SDG&E, AReM, CCDC, CMUA, EPUC, Merced ID/Modesto ID, TURN and DRA.

A list of acronyms and abbreviations used in this decision is included in Appendix B. A list of certain terms used in this decision is included in Appendix C.

[10] Merced ID and Modesto ID filed joint opening and reply briefs.

2.1. D.04-12-048

In Rulemaking (R.) 04-04-003, the Commission issued D.04-12-048, which adopted the 2004 long-term procurement plans (LTPPs) of the IOUs. As part of that decision, to ensure a long term, reliable energy supply for California customers and to address the utilities' concern they could end up over procuring resources and incurring the stranded costs associated with these resources given the potential for a significant portion of their load to take service from a different provider, the Commission authorized the IOUs to recover stranded costs associated with new PPAs and utility-owned generation from all customers. Among other things, the Commission found and concluded the following:

> In general, we agree that the utilities should be allowed to recover their net stranded costs from all customers, which may require the application of additional cost responsibility surcharges or other non-bypassable surcharges. (Finding of Fact 33.)
>
> Ensuring that utilities be allowed to recover their net stranded costs from all customers meets the Commission's goals of providing "the need for reasonable certainty of rate recovery" (as required under AB 57 and noted in the June 4th ACR) as well as best ensuring that California meets its energy needs. (Conclusion of Law 13.)
>
> Requiring departing customers to assume a fair share of their costs, and thus avoiding cost shifting, is also consistent with the Commission's policy of holding captive ratepayers harmless as required by state law. (*See* Conclusion of Law 14.)

While D.04-12-048 authorized the IOUs to recover the stranded costs of their electric resource commitments, the decision did not specify the

implementation mechanism for the NBC. Consequently, implementation details were deferred to R.06-02-013,[11] and subsequently to Track 3.

Additionally, the issue of applicability of non-bypassable charges as it relates to forecasted departing load (e.g., historic municipal and distributed generation (DG) load shedding) was also included in Track 3.[12]

2.2. D.06-07-029

As part of R.06-02-013, the Commission issued D.06-07-029 which adopted a cost allocation mechanism (CAM) that allows the advantages and costs of new generation to be shared by all benefiting customers in an IOU's service territory. The decision designated that the IOUs should procure the new generation through long-term PPAs. By the CAM, the capacity and energy from the PPAs are unbundled and the rights to the capacity are to be allocated among all load serving entities (LSEs) in the IOU's service territory. Such allocated rights to the capacity can be applied toward each LSE's resource adequacy requirements. The LSEs' customers receiving the benefit of this additional capacity would pay only for the net cost of this capacity, determined as a net of the total cost of the contract minus the energy revenues associated with dispatch of the contract. Among other things, the Commission also found and concluded the following:

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[11] For instance, see p. 15 and Conclusion of Law 16 of Resolution E-4046.

[12] In a September 10, 2007 electronic-mail response to a September 7, 2007 electronic-mail inquiry issued by the parties during their preparation of the master briefing outline, the assigned Administrative Law Judge (ALJ) for Track 3 indicated that while it might have been appropriate to address this issue as part of forecasting in Track 2, it did not appear that it was clearly stated as an issue in that track, and therefore, it would be addressed in Track 3.

> This mechanism disaggregates the energy and capacity components of the newly acquired generation, so that the only non-bypassable charge levied is for the net capacity costs, and the non-IOU LSEs retain the ability to manage their energy purchases. (Finding of Fact 21.)
>
> It is reasonable, and consistent with law, for the Commission to adopt this limited and transitional cost allocation mechanism to support the development of new generation by having the costs and benefits shared by all customers. (Conclusion of Law 5.)
>
> The IOUs shall make an election at the time they seek contract approval from this Commission whether or not they intend that the cost allocation mechanism adopted by this decision should apply to the contract. The Commission's decision on the IOUs' applications will determine the cost allocation mechanism that will apply. Contracts ineligible for this cost allocation mechanism, or contracts to which the IOUs elect not to apply this cost allocation mechanism at the time seeking Commission approval of the contract, are still subject to the rules of D.04-12-048. (Conclusion of Law 6.)
>
> It is reasonable to defer many of the implementation details of this cost-allocation mechanism to Phase II of this proceeding along with associated ratemaking issues. (Conclusion of Law 10.)

In D.07-09-044, the Commission adopted an unopposed settlement agreement that included the procedures for energy auctions, the products offered by the IOUs in the energy auctions and the allocation of the benefits and net costs of the new generation contracts designated for the energy auction process. The Commission elaborated that additional implementation details would be addressed in Track 2 of the proceeding. Today's decision addresses any remaining CAM implementation issues identified by parties. The issue of applicability consistent with that described above for D.04-12-048 is also addressed in the context of the CAM.

3. Guiding Principles

In addressing issues related to NBCs, the Commission has generally applied the bundled customer indifference principle, whereby bundled customers should be no worse off, nor should they be any better off as a result of customers choosing alternative energy suppliers (ESP, CCA, POU or customer generation).[13] The Commission has also supported the principle that stranded costs should be recovered from those customers who benefited from the stranded asset,[14] as well as those customers on whose behalf the IOU incurred these costs. It is reasonable that we continue to use these guiding principles in reconciling issues related to the implementation of the D.04-12-048 and D.06-07-029 NBCs.

The notion that each customer pay its fair share of the costs the IOU incurred on behalf of this customer or the load associated with this customer is part of these guiding principles.[15] Therefore, the rule is that when costs are

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[13] For example, in D.04-12-048, Finding of Fact 28, the Commission stated, "The threshold policy issue underlying cost responsibility surcharges is to ensure that remaining bundled ratepayers remain indifferent to stranded costs left by the departing customers."

[14] For example, in D.04-12-048, Finding of Fact 15, the Commission stated, "Allowing the utilities to recover stranded costs from all customers who benefited is consistent with recent Commission policy with regards to new resource additions." Also in D.03-04-030, Finding of Fact 20, the Commission stated, "Granting exceptions to certain portions of the CRS for customer generation up to 3,000 MW [megawatt] will not result in any cost-shifting among customers, since costs for those MW were not incurred by DWR."

[15] Pub. Util. Code § 366.2(d); D.02-11-022, p. 158, Conclusion of Law 21; D.03-04-030, p. 39; D.03-07-028, p. 13; D.04-12-046, p. 24; D.04-12-048, p. 57; D.05-09-022, pp. 15-16.

incurred on its behalf, that customer must pay its fair share of the costs. A corollary rule is that if no costs are incurred on its behalf, then the customer's fair share can be determined to be zero.[16]

With respect to the CRS established by this decision to implement the D.04-12-048 NBC, we are guided by previously established principles used to implement the existing CRSs for DA, CCA, MDL and CGDL.[17]

4. Applicability of Stranded Cost Recovery and Net Cost Allocation NBCs

4.1. Forecasted Departing Load

Whether or not departing load should be forecasted and reflected in the IOUs' load forecasts is not an issue in this track of the proceeding. The structure of the load forecasts used in developing the LTPPs has already been addressed in Track 2, and any related issues have been reconciled in D.07-12-052.[18] Now in Track 3, we are considering the implications of any forecasted departing loads, as determined in D.07-12-052, on the applicability of NBCs to certain customer groups. This has been raised as an issue in the context of both MDL and CGDL and recognized as an issue within the scope of this track of the proceeding.

The IOUs have taken the position that the Commission has already determined that departing load forecasts should not be a basis for releasing

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[16] The Legislature has given the Commission the authority to determine the fair share and the fair share can be determined to be zero. (*See* Pub. Util. Code, § 366.2(d); D.03-07-028, p. 61; D.04-12-046, pp. 38-39; D.04-12-059, pp. 13-14.)

[17] Appendix D provides a summary of consumer responsibility for various IOU/DWR cost elements related to CRSs.

[18] The LTPP Phase II, Track 2 decision in this proceeding.

departing customers from having to pay the NBCs. In D.04-12-048, the Commission stated, "In general we agree that the utilities should be allowed to recover their net stranded costs from all customers, which may require the application of additional cost responsibility surcharges or other non-bypassable surcharges." (Finding of Fact 33.) Furthermore, in D.06-07-029, we stated, "It is reasonable, and consistent with law, for the Commission to adopt this limited and transitional cost allocation mechanism to support the development of new generation by having the costs and benefits shared by all customers." (Conclusion of Law 5.) We continue to support these general determinations.

As a part of determining the cost allocation, we need to examine and determine the fair share of certain customers, in particular MDL and CGDL, because of the implications of the LTPP load forecasts that anticipate departing load based on historical trends. This consideration of the fair share is necessary to ensure bundled customer indifference and the proper alignment of benefits and cost responsibility.[19] Based on such examination, as discussed below, we have considered the extent to which MDL and CGDL customers will be subject to both the D.04-12-048 and D.06-07-029 NBCs.

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[19] Addressing this issue now is consistent with D.07-11-051 wherein the Commission, in modifying D.06-07-029, stated, "Our definition of benefiting customers subject to the cost allocation mechanism does not include current POU customers, and departing customers who take POU service will not be able to avoid cost responsibility pursuant to D.04-12-048, as modified by D.05-12-022. As noted in D.04-12-048, Ordering Paragraph 9, IOUs are required to forecast and plan for departing load as they file their biennial long-term procurement plans which establish each IOU's long-term resource needs. Further, we will consider issues of need in a subsequent phase of this proceeding and POUs may address whether specific facts suggest refining our approach to the allocation of costs to municipal departing load." (Ordering Paragraph 1(h), emphasis added.)

4.1.1. Positions of the Parties

In general, the issue revolves around the position of certain parties[20] that the IOUs' load forecasts should reflect reasonable amounts of MDL and CGDL, the IOUs should not be procuring for that forecasted DL, there should therefore be no associated costs, and consequently the proposed new generation NBCs should not be imposed on those departing customers.

The principal objections to this proposal have been raised by the IOUs and TURN. PG&E argues this proposal should be rejected because:

1. the Commission has already declined to exclude departing load that is forecast;

2. for policy and planning reasons, forecasting is not an appropriate basis for exceptions;

3. the intervenors have not demonstrated that PG&E has forecast specific departing loads;

4. parties that are not willing to bear the burden of incorrect forecasts should not be excluded; and

5. allowing exceptions based on forecasts will lead to endless litigation and disputes.

SCE adds that departing load introduces additional uncertainty and error into the utility's load forecast and results in additional costs. To avoid unfairly shifting these risks and costs to remaining bundled service customers, according to SCE, all customers taking bundled service at the time resource commitments

[20] This position is advocated by CMUA, Merced ID, Modesto ID, and CCDC, each on behalf of its specific interests.

are made should be responsible for the above-market (stranded) costs of those resources, if any, either through paying the bundled service rate or a CRS designed to recover these costs. SDG&E makes a similar argument.

TURN argues that when the average cost of a utility's supply portfolio is higher than the current market price of power, any departing load – forecasted or not – will increase the average cost to the remaining bundled service customers, resulting in stranded costs.

4.1.2. Discussion

As noted by the IOUs, the Commission has previously stated that the D.04-12-048 net stranded costs should be recovered from all customers, and the CAM was adopted in D.06-07-029 to support the development of new generation by having the costs and benefits shared by all customers. However, in considering the effects of forecasted departing load on the applicability of the NBCs, we must ensure the outcome of our determination is, to the extent possible, consistent with the preservation of bundled customer indifference and cost recovery from customers on whose behalf resources were procured. In that regard, we must determine the fair share of the departing load for the costs the IOU incurred on behalf of that load. In D.04-12-048, the Commission stated:

> A major issue in this proceeding is the extent to which the utilities will be compensated for investments or purchases that they must make in order to meet their obligations to provide reliable service to their customers. The implementation of CCA, departing municipal load, and the potential for lifting, in some form or another, the current ban on allowing new DA all create a great degree of uncertainty as to the amount of load the existing utilities will be responsible for serving in the future. Given the potential for a significant portion of the utilities' load to take service from a different provider, the utilities are concerned that they could end up

> over-procuring resources and incurring the stranded costs associated with these resources.
>
> One solution to this problem, discussed above, is the adoption of load forecasts that seek to address, to the extent possible, the uncertainties over the future load that the utilities will be responsible for. Another solution is for the utilities to be entitled to recover any stranded costs occurring as a result of their efforts to meet their load obligations.

Given these two possible solutions to offset the effects of departing load, it is necessary to first determine what types of departing load are reflected or not reflected in the adopted LTPP load forecasts.

Issues related to load forecasts were litigated in Phase II, Track 2 of this proceeding and are addressed in detail in D.07-12-052. In determining the appropriate load forecasts, D.07-12-052 relied heavily on the CEC's Integrated Energy Policy Report (IEPR) process and states the following:

> The last LTPP decision, D.04-12-048, directed the IOUs to prepare a Medium-Load Plan Scenario in future LTPPs using the CEC's IEPR base case load-forecast scenario or an Alternative Base Case load-forecast scenario, if the utility chose to file one. In R.04-04-003, the predecessor LTPP rulemaking that resulted in D.04-12-048, the assigned Commissioner issued a ruling on March 14, 2005 (hereinafter referred to as the "IEPR Ruling") directing all parties interested in the IOUs' load forecasts for 2006 to participate in the CEC's 2005 IEPR process since the Commission did not intend to re-examine specified issues resolved during the IEPR process. (D.07-12-052, p. 22, footnote omitted.)
>
> We clarify in this decision, and will reiterate in the OIR for the next LTPP proceeding, that the IOUs are to use the CEC's forecast in their LTPPs. The CEC's IEPR process is the proper forum to litigate and contest issues related to each IOU's demand forecast. If an IOU believes that the CEC's forecast is too "conservative" or that the CEC should use different forecasting models, data or other inputs,

that IOU must bring those issues up and have them resolved in the IEPR proceeding. (D.07-12-052, pp. 27-28.)

We find it prudent to review load forecast sensitivities, but for purposes of granting procurement authority, need determination should be based on the CEC's base forecast under baseline (1-in-2) temperature conditions pursuant to D.04-12-048. (D.07-12-052, p. 28.)

We concur with many of the concerns raised by the CEC and other parties. To address these concerns and conform to our own policy directives, we base the IOU need determination tables on the CEC's base case, 1 in 2 summer temperature demand forecast (the three need tables, PGE-1, SCE-1, and SDGE-1, all use the forecasts from CEC's 2007 IEPR issued on November 21, 2007). (D.07-12-052, p. 29.)

While we recognize that the 2007 IEPR forecast estimates were not vetted in this proceeding, many aspects of the IEPR forecasting process were. The IEPR process is a public one, involving many of the same participants that are parties to this proceeding, and the IEPR document is a public document. We find it prudent to update the forecast estimates used as inputs in this decision based on the most current public information available to us, particularly given the long time lag that has occurred since the LTPPs were developed. The California Energy Demand Forecast, 2008-2018, the underlying load forecast which the 2007 IEPR assumes, had not been officially adopted by the CEC, as of the mailing of this Proposed Decision. We note that the incorporation of the draft 2007 IEPR demand forecast into our overall needs analysis may give certain parties concern, however, we believe that the draft forecast provides a better 'snapshot' of the current needs of the system. (D.07-12-052, footnote 38, pp. 29-30.)

As indicated above, the LTPP load forecasts adopted by D.07-12-052 were based on the November 2007 California Energy Demand 2008-2018 Staff Revised Forecast[21] (2007 IEPR Demand Forecast) and are shown in Tables PGE-1, SCE-1, and SDGE-1 of that decision. Each table indicates the forecasts were based on the CEC's 2007 IEPR 1-in-2 peak demand. For PG&E and SCE the tables indicate that the service area calculation includes bundled and DA customers and excludes POUs. This is verified by examination of the 2007 IEPR Demand Forecast, on which the D.07-12-052 load forecasts are based. For example for the year 2007, D.07-12-052 represents the 1-in-2 Service Area Summer Temperature demand to be 19,845 MW for PG&E. This is the load used in D.07-12-052 to determine PG&E's Service Area Surplus (Deficit) for that year. That demand amount can be traced back to the 2007 IEPR Demand Forecast by adding PG&E's bundled load of 18,827 MW and PG&E direct access load of 1,017 MW, as shown on Form 1.5b.

In the IEPR process, IOUs are required to quantify and document their assumptions about migrating load. This information is needed to support compliance with AB 1723 (PRC 25302.5), which require all LSEs to provide the CEC with their "forecasted load that may be lost or added" by a POU or CCA or served by an ESP. The CEC is to perform an assessment of migrating load in each IOU service territory and submit the results to the CPUC.

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[21] http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF

That bundled load does not include POU load (and the associated MDL)[22] is demonstrated on Form 1.4b in the 2007 IEPR Demand Forecast which shows bundled and direct access loads separately from POU loads. In general, forecasts of demand, including that for MDL, reflect historical consumption, economic and demographic projections, weather adjustments and specific inputs from LSEs.[23]

That CGDL is also reflected in the D.07-12-052 adopted load forecasts can be verified by examination of the 2007 IEPR Demand Forecast in the discussion related to Self Generation. It states, "As discussed in Chapter 1, the peak demand forecast is reduced by the projected effects of the SGIP, CSI and other similar programs. The effects of these programs are forecast based on recent trends in installations." (2007 IEPR Demand Forecast, p. 74.)[24] Historic and forecasted CGDL peak demand is shown as "Total Private Supply" on Form 1.4 of the 2007 IEPR Demand Forecast.

The above discussion of how departing load is reflected in the adopted load forecasts is also consistent with our understanding of how departing load is

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[22] The 2007 IEPR Demand Forecast, p. 35 indicates that the individual LSE forecasts were also adjusted to account for load migration (customers migrating from one service provider to another).

[23] 2007 IEPR Forecast, p. 35.

[24] The referenced Chapter 1 states in part, "To forecast future self-generation load, staff used the IOU reports on completed new interconnections and pending applications to develop projections of capacity additions of new interconnections. (Footnote omitted.) The interconnection reports provide a detailed picture of capacity addition trends."

considered in the load forecasts prepared by the IOUs.[25] In D.07-12-052, we stated:

> Regarding parties' concerns over PG&E's assessment of departing load, we concur with PG&E's response that its analysis of system need is not impacted by possible future load shifting due to DA and CCA, and that future DG and MDL is captured by historical trends used to develop the forecast.[26]

Similar statements are made with regard to SCE and SDG&E departing loads.[27]

Based on the load forecasts adopted in D.07-12-052, it would be appropriate to employ both of the solutions expressed in D.04-12-048 related to IOU procurement for departing load. For IOU customers that are eligible to, and do, choose DA service from an ESP and for customers that decide to use a CCA, D.07-12-052 indicates that their loads are included in the adopted load forecasts on which the LTPPs are based. Therefore, the IOUs would be procuring resources on their behalf, and NBCs should be imposed on these customers when they cease taking procurement services from the IOUs, in order to maintain bundled customer indifference. Imposition of the NBCs is appropriate,

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[25] Regarding the load forecasts prepared by the IOUs, the effects of CGDL were reflected, as indicated in each IOU's LTPP which included a section on forecasting DG (PG&E's 2006 LTPP, Volume 1, pp. IV-20 – IV-25, SCE's 2006 LTPP, Volume 1B, pp. 16-24, and SDG&E's 2006 LTPP, pp. 194-197). It was also established that the CEC demand forecast reflects embedded amounts of DG (CCDC, Wong, 8 Tr. 1046-1047). MDL is implicitly reflected in SCE's load forecast as a decline in SCE's bundled load growth through the extrapolation of historical data. (*See* Exhibit 37, p. 37 and SCE, Canning 2 RT, pp. 216-218.) PG&E similarly takes projected POU departing load into account in its load forecast. (*See* PG&E, Aslin, 5 RT, pp. 647-660.)

[26] D.07-12-052, pp. 34-35.

[27] *Id. at* pp. 39 and 42.

because CCA, and to an extent customers currently eligible to return to DA, create uncertainty regarding what loads the IOUs will be required to serve. At this time, there is insufficient history of such transactions and limited knowledge of customers' intent to pursue such transactions in the future, for the IOUs to use in determining how much, or how long, power should be procured on such customers' behalf. Planning for these customers' needs and imposing the NBCs if and when these customers choose alternative procurement services is a reasonable way to address the problem.[28]

On the other hand, D.07-12-052 indicates that future CGDL and MDL are captured by historical trends used to develop the load forecasts. Therefore, the forecasted loads associated with MDL and CGDL customers are not included in the D.07-12-052 adopted load forecasts. This is consistent with the solution expressed in D.04-12-048 whereby the Commission would adopt load forecasts that seek to address, to the extent possible, the uncertainties over the future load that the utilities will be responsible for.

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[28] In its Opening Comments on the Proposed Decision, p. 5, AReM indicates that SDG&E's approved load forecasts reflect reasonably foreseeable DA load migration and that it follows that based on the rationale for excluding MDL and CGDL customers from new generation NBC cost responsibility, DA-eligible customers located in SDG&E's service territory should also be exempt from the new NBCs. The record indicates otherwise. Form 1.4b of the 2007 IEPR Demand Forecast shows a constant forecast of DA demand over time for SDG&E. Also, in its Reply Comments on the Proposed Decision, SDG&E clarified that while DA load shown in its compliance capacity tables increase slightly over the planning period, this increase is driven by the assumption that usage per customer increases slightly over time not and not a forecast of DA customer increases. Therefore, it is evident that DA load migration has not been forecasted for SDG&E, and DA eleigible customers in SDG&E's service territory should not be excluded from the new generation NBCs..

We note that the use of historic information and trends to reflect future departing load reduces some risk to the IOUs of possibly adopting overly optimistic estimates and tends to limit the dispute and litigation related to what the appropriate levels of departing load should be. For instance, PG&E states that MDL bypass is no longer expected to be materially different than recent trends captured in the historic data.[29] While there may be differences between the amounts of departing load implicit in the load forecasts and the amounts recorded on a year-by-year basis, over time any such variations should level out and bundled customer indifference will be maintained. Also, as long as historic information and trends are the basis for reflecting the departing load in the load forecast, unexpected annual variations between actual and assumed departing loads will result in the assumed forecast departing load levels being adjusted up or down in the future based on the historic amounts, again resulting in bundled customer indifference being maintained over time.

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[29] Exhibit 211, Response to Question II.2.

Forecasting the effects of CGDL and MDL has been done in the past[30] and, as discussed previously, is done as part of the CEC's IEPR process which, at least for the foreseeable future, will be the basis for Commission's LTPP load forecasts. We reiterate the guidance provided in D.07-12-052, that the CEC's IEPR process is the proper forum to litigate and contest issues related to each IOU's demand forecast, including any concerns related to the accuracy of the predicted MDL and CGDL in the CEC forecast.

What we must consider now is (1) what it means for this departing load to be reflected in the load forecast, and (2) given that meaning, whether these departing load customers should be fully responsible, partially responsible, or not responsible at all, for the new generation NBCs established by D.04-12-048 and D.06-07-029.[31] This is integral to our determination of the departing load's fair share.

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[30] CGDL has been excluded from procurement related charges based on load forecasts in previous Commission decisions. (*See* D.03-04-030, p. 54, D.04-12-048, Ordering Paragraph 11, and D.04-10-035, p. 20.) Regarding MDL, the Commission excepted transferred MDL indentified in the Bypass Report in D.04-11-014 (see pp. 4 and 40), Findings of Fact 3 and 18, Conclusion of Law 5, and Ordering Paragraph 4); the Commission excepted new MDL associated with the transferred MDL identified in the Bypass Report in D.04-11-014 (*see* pp. 4-5, 21, Findings of Fact 10 and 11, and Ordering Paragraph 2) and the Commission granted an exception to new MDL of "existing" POUs in D.03-07-028 (see p. 61, Findings of Fact 12, 13, and 16, Conclusions of Law 9 and, 10, and Ordering Paragraph 6) and extended it to other new MDL on the basis that new MDL was implicitly accounted for in the utility forecasts (*see* D.04-11-014, pp. 10-13, Findings of Fact 2 and 4, and Conclusions of Law 1 and 3, and Ordering Paragraphs 1 and 2).

[31] The fact that system needs are not impacted by possible load shifting due to DA and CCA means that the load forecasts are not reduced to reflect DA and CCA. It is therefore unnecessary to examine the implications of forecasted load reductions in this context, and no party has recommended that we do so.

Exclusion of MDL and CGDL from the load forecast can only logically be interpreted to mean that the LTPP, which uses that load forecast to determine resource needs in the forecast year, does not include any resources to serve that departing load in that forecast year and beyond. Accordingly, in such circumstances, it would be reasonable to determine that the fair share of departing load for paying the new generation NBCs would be zero. Stranded costs are avoided for these forecasted departures via the combination of (1) the layering of generation procurement by the IOUs (both in terms of procurement of longer term, shorter term and "spot" market resources and in terms of the sequenced procurement of resources which in turn results in resources regularly dropping out of the portfolio as contracts expire) and (2) forecast increases in load from new and existing customers.

As discussed below, in applying this departing load fair share concept, we have considered new generation resources that become operational (1) during the year that these customers depart and beyond and (2) before these customers depart.

For those new generation resources that become operational during the year that MDL and CGDL customers depart and beyond, those departing load customers should not be responsible for any new generation NBCs. That is because when the commitments for those resources are made the load forecasts on which procurement needs are based do not include loads related to MDL and CGDL. Such departing loads have been forecasted and are not included in the load forecasts used in determining the need for those resources. Those resources are therefore not procured on behalf of these departing load customers for any time period and their fair share of the costs should be zero.

We must also consider cost responsibility related to those new generation resources that become operational and begin to provide energy prior to the date that these customers depart the IOUs' systems. For transferred MDL and CGDL customers, they would have taken bundled service from the utility, for some period of time, prior to the year in which they depart. For the time that they are bundled service customers, they would pay for any operative new generation resources as part of their bundled service rates. However when they depart, their cost responsibility for such resources should end. That is because, at the time the resource commitments are made, (1) the LTPP load forecasts exclude forecasted amounts of MDL and CGDL; (2) these customers will eventually become the departing customers for which those amounts of MDL and CGDL are forecasted; and (3) therefore, in effect, these customers' loads are only reflected in the LTPP load forecast for the years in which they are bundled service customers. Therefore, (1) the IOUs' procurement needs related to these customers are only identified and planned for in the years in which they are bundled service customers; (2) the IOUs' procurement commitments are made on behalf of these customers only for the time that they are on bundled service; and (3) these customers' fair share of the costs related to these resources should be zero after they depart.

Consistent with our overall guiding principles for resolving NBC implementation issues, these departing customers should not pay any NBC related to new generation resources that were not procured on their behalf, as these customers' fair share would be zero. We will not impose either the D.04-12-048 or D.06-07-029 NBCs on MDL and CGDL, since these classes of departing load are reflected in the load forecasts on which the LTPPs are based. Also, since there are no resources or associated costs in the forecast year related

to the load departing in that year, there is no cost shifting to bundled customers when these departing customers leave.

In supporting the IOUs, TURN argues that the question of whether or not some amount of future departing load may have been reflected in a prior forecast sponsored by a utility or adopted by this Commission or the CEC should be irrelevant to the applicability of the NBCs at issue in this proceeding. It is TURN's position that when the average cost of a utility's supply portfolio is higher than the current market price of power, any departing load – forecasted or not – will increase the average cost to the remaining bundled service customers, resulting in stranded costs. We do not agree with TURN's conclusion that therefore under all such circumstances departing load customers should be assessed an NBC.

The more important consideration is the appropriate measure of ratepayer indifference. All other things being equal, exclusion of forecasted departing load from the LTPP load forecasts and exclusion of MDL (with the exception of large municipalizations) and CGDL customers from cost responsibility for new generation resources after the customers depart leaves existing bundled customers with the same cost responsibility as was anticipated when the LTPP load forecasts were made. That is simply because the forecasted departing customers were not anticipated to be served after they depart because their loads are excluded from the forecasts on which the procurement decisions are based. The fact that the forecasted departing customers actually depart does not affect the costs to the bundled customers when compared to costs associated with the assumptions in the sales forecasts and procurement plans associated with the new generation resources. In that regard, bundled customers are appropriately indifferent to the departure of the forecasted departing customers.

To summarize, as opposed to DA and CCA, MDL and CGDL do not create a large degree of uncertainty regarding what loads the IOUs will be required to serve. The adopted load forecasts directly address the effect of MDL and CGDL, and the consequent LTPPs are not developed to serve those departing loads. These forecasts justify our determination that the fair share of these departing load customers will be zero. Accordingly, imposition of the D.04-12-048 and D.06-07-029 NBCs is not necessary for MDL or CGDL customers. However, with a large municipalization, we take a different approach as discussed in Section 4.1.4 below.

4.1.3. TURN's Recommendation for a Binding Notice of Intent Process

TURN argues that a binding notice of intent (BNI) process provides a much more robust way of dealing with the uncertainty regarding future departing loads than endless debating over who included or should have included which potential departing loads in a past forecast. TURN notes Commission has adopted this approach for CCA load.

In general, we agree with TURN's position that if a potential departing customer is not willing to commit to a firm departure date via a BNI, then that customer should remain liable for the potential stranded costs associated with any commitments the utility enters into prior to the date of the actual departure. However, that customer should only be responsible for commitments that were made on its behalf. This principle is embodied in the determination of the fair share. In the case of CCA, the IOU's are procuring and making procurement commitments on behalf of potential CCA customers until the specific dates indicated by the BNIs. That is because loads associated with these customers are included in the IOUs' load forecasts on which their procurement decisions are

based. That is not the case for MDL and CGDL customers with respect to the new generation NBCs. As indicated by D.07-12-052, the IOUs exclude these departing loads in their forecasts. As stated previously, for this reason, the IOUs are essentially not procuring on behalf of MDL and CGDL customers in the year they depart and beyond. Accordingly, it is reasonable to determine that the fair share for the new generation costs would be zero. Although the BNI process may be a viable approach for determining when IOU procurement on behalf of certain customers ends, it is not relevant in addressing the NBC applicability issue of whether these customers should be assessed any NBC at all under a fair share analysis.

4.1.4. Effect of Large Municipalizations

As discussed above, our analysis of the fair share cost responsibility for MDL is based in large part on our determination that such load is reasonably reflected in the historical trends used in developing the adopted LTPP load forecasts. However, at some point the historical trends of MDL may no longer reasonably represent the amounts of MDL that will occur. This point would be reached if there is a "large municipalization" in the forecast year. While there is no precise measure of what constitutes a "large municipalization," in the context of this decision, we are defining "large municipalization" as any portion of an IOU's service territory that has been taken control of or annexed by a POU where the amount of load departing the IOUs' service territories due to the municipalization is of such a large magnitude that it cannot reasonably be assumed to have been reflected as part of the historical MDL trends used in developing the adopted LTPP load forecasts. SCE states that its long-range retail

load forecasts use historical data starting from 1991 and that all sizeable annexations occurred prior to 1991.[32] PG&E indicates that it would likely remove any large municipalizations from the historical data but adds that it is difficult to quantify what "large" would be.[33] SDG&E indicates that it has no existing or planned municipalization at this time.[34]

Therefore, if a large municipalization occurs in a particular year, the associated departing load would logically have been part of that year's LTPP load forecast, and the IOUs would have been making new generation resource commitments on behalf of those departing customers up until the time they depart or provide appropriate notice of departure. Unlike that for MDL and CGDL, which are reflected in the LTPP load forecasts, it cannot be argued that large municipalization load, which is not forecasted for LTPP purposes, should be excluded from new generation cost responsibility. That is because when the commitments for resources that were procured prior to these customers' departure are made, there is no forecasted information that would indicate that customers would be departing due to large municipalizations at any time over the lives of the resources. Procurement would have been planned accordingly. Therefore, under the principle of allocating fair share, large municipalization departing customers should be fully responsible for the new generation NBCs.

Imposition of new generation NBCs on customers departing due to large municipalizations shall be accomplished through a separate application filed by

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[32] Exhibit 212, Response to Question 2.

[33] Exhibit 211, Response to Question II.2.

[34] Exhibit 213, Response to Question 8.

the affected IOU. Customers' NBC cost responsibility shall be determined through a fair share analysis based on the record of that proceeding. The IOU has the burden to show the departures are within the definition of a large municipalization, especially as it relates to how the large municipalization is or is not reflected in the adopted LTPP load forecasts.

For purposes of determining when the IOUs should stop procuring new generation resources for these departing customers, a BNI process similar to that established for CCAs is reasonable.[35] As determined in D.04-12-048 and D.05-12-041, customers choosing CCA service will be responsible for new generation NBCs associated with the resources procured prior to departure if no BNI is submitted. If a BNI is submitted, the customer will pay only the NBC associated with new generation resources procured prior to the date the BNI is submitted to the IOU. In the event that the CCA cannot meet the BNI date, the CCA will be liable for any net incremental procurement costs incurred by the utility. The IOUs should make this process available for large municipalizations.

If the large municipalization entity does not wish to provide a BNI, the actual departure date is a reasonable date to determine large municipalization NBC cost responsibility, similar to that for CCAs. While we prefer this BNI process, we will not strictly impose its conditions, recognizing that there may be a reason, possibly having to do with the timing of the processes in finalizing a large municipalization, for the entity not to choose either the use of the BNI or the actual departure date, but to recommend some alternative date instead.

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[35] CCAs and large municipalizations are similar in that there is potential for significant load migration and neither is reflected in the LTPP load forecasts.

However, we will impose the burden on the large municipalization entity to demonstrate the reasonableness of using its proposed date as opposed to a BNI date or the actual departure date for determining when the IOU should no longer procure new generation resources for the departing customers.[36] If that burden is not met, the actual departure date will be used for that purpose.

4.1.5. New Western Area Power Administration (WAPA) Departing Load and Split Wheeling Departing Load

PG&E requests that it be made clear that the new generation NBCs also apply to new WAPA departing load[37] and split wheeling departing load,[38] consistent with D.03-09-052 and D.06-05-018.[39] In those decisions, the Commission determined that:

> A CRS shall be imposed on split wheeling preference power customers to the extent they received a portion of their power through PG&E bundled service to the extent such power exceeds the customer's CRD in the manner contemplated under the existing provisions of Contract 2948A. (D.03-09-052, Ordering Paragraph 4)

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[36] If the large municipalization entity is of the belief that, at some point in time, the IOU should have known the load would be departing by a certain date, the municipal entity should explain why a BNI commitment could not have been made by the municipal entity to reflect that.

[37] New WAPA departing load is additional customer load of certain so-called 'new allottee" customers who, for example, were served by PG&E under its retail tariffs prior to expiration of Contract 2948-A with WAPA but are now served by WAPA.

[38] Split wheeling departing load is that portion of the load of certain so-called "split-wheeling" customers which, for example, was served by PG&E under its retail tariffs prior to the expiration of PG&E's Contract 2948-A with WAPA but is now served by WAPA.

[39] PG&E Initial Comments on the Proposed Decision, p. 12. There were no replies to this comment.

> The following new Ordering Paragraph (OP) 8 is added (reordering current OPs 8 and 9): "PG&E is directed to promptly file an advice letter with the appropriate amendments to its tariff to bill and collect CRS and other applicable nonbypassable charges from preference power customers consisting of 'Additional Customer Load' relating to the specific list of delivery points listed in Appendix C of the WDT Agreement, that have taken bundled service from PG&E on or after February 1, 2001, and subsequently reduced or terminated such service to take electric service from WAPA or another similarly situated entity." (D.06-05-018, Ordering Paragraph 5)

In its testimony, PG&E included such loads as being subject to the D.04-12-048 NBC.[40] No party provided responsive testimony or other evidence that shows such loads should be excluded from that charge.

Regarding the D.06-07-029 NBC, the Commission stated:

> In summary, Section 380 allows an IOU to recover the costs it incurs to sustain "system reliability and local area reliability" from all customers "on whose behalf the costs are incurred." We construe benefiting customers as defined in Section IV.B.1 as those customers on whose behalf the costs are incurred. (D.06-07-029, p. 41.)

No party provided testimony or other evidence that would indicate that PG&E would not incur the D.06-07-029 NBC related costs on behalf of new WAPA departing load and split wheeling departing load customers while they are customers of PG&E. Therefore, we conclude that the new generation NBCs should apply to new WAPA departing load and split wheeling departing load consistent with our rationale for assigning generation related cost responsibility in D. 03-09-052 and D.06-05-018.

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[40] *See* Exhibit 7, p. II-5.

4.2. AReM's Request for Confirmation Regarding Customers Currently Eligible to Return to DA

AReM asks the Commission to confirm that bundled service customers who are eligible to return to DA should also be exempted from the NBC associated with D.04-12-048. PG&E, SCE, SDG&E, and TURN oppose AReM's request.

4.2.1. Parties' Positions

In D.04-12-048, the Commission authorized the IOUs to recover the stranded costs of new utility procurement resulting from departing load from "all customers, including departing [load/customers]."[41] AReM argues that, when read in context, this wording specifically excludes customers that are currently eligible for direct access. That is, "departing load" and "departing customers," as used in D.04-12-048, do not include customers that are currently on direct access or customers that are currently on bundled service but are eligible for direct access.

The opposition's principal response to AReM's assertion is that the Commission in D.04-12-048 determined that the IOUs should be allowed to recover stranded costs from all bundled customers, including departing load customers. There are no stated exceptions.

AReM supports its conclusion by citing D.03-12-059 and D.04-06-011 where the Commission stated various customers that are currently ineligible for direct access should be obligated to pay for stranded costs for 10 years.

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[41] D.04-12-048, pp. 60 and 63.

In reply, PG&E states that in D.04-12-048, the Commission referenced these two decisions to support its decision to limit NBCs to 10 years. It did not cite these decisions as a basis for excluding DA eligible customers. PG&E adds that notably, just before the language quoting these two decisions, the Commission states that stranded costs should be recovered from all customers, which would include DA eligible customers.

AReM also references D.05-09-022 which addressed various petitions for modification of D.04-12-048, including the petitions filed by AReM and ESPs in which it was argued that the Commission does not have the authority to impose NBCs on direct access customers for purposes of allowing the IOUs to recover stranded costs associated with new procurement commitments. The Commission held, "[W]e may lawfully hold future direct access customers responsible for the recovery of new generation costs."[42] AReM emphasizes the word "future." AReM argues that the Commission made no reference to customers that are currently eligible for direct access, indicating that would have been a glaring omission if the Commission had actually intended for the stranded cost NBCs authorized in D.04-12-048 to apply to such customers.

In reply, TURN states that today's bundled service customers who happen to be eligible for DA and subsequently depart to take service from an AReM member are precisely "future" direct access customers as specified in D.05-09-022. TURN also states that the mere fact that the Commission did not single out "currently bundled customers who are eligible to return to direct access" from other types of departing load does not prove AReM's point. If

[42] D.05-09-022, p. 15.

anything it proves the opposite – that all types of departing load are subject to the NBC.

AReM also states that arguments for imposing the charge on DA eligible customers ignore the existence of the elaborate rules developed by the Commission to govern the movement of DA-eligible customers to and from direct access so as to prevent gaming and costs being shifted to bundled customers. Under those rules, if a customer that is on direct access wants to return to bundled service, it must provide the utility with six months advance notice and will only become eligible to receive bundled service from the utility at the same rate as other customers at the end of the notice period. In addition, the customer is required to remain on bundled service for a minimum of three years, and if the customer wants to go back to direct access after the end of its minimum three-year commitment period, it must provide the utility with six months advance notice.

AReM argues that the Commission left open the possibility that it would later extend the minimum commitment period beyond three years if there was evidence that a longer period was "necessary to avoid stranding long-term portfolio supply obligations undertaken to serve DA customers returning to bundled status…."[43] According to AReM, the Commission has not seen a need to do so, because the Commission's rules to prevent cost shifting by DA customers also ensure that DA customers impose no costs on bundled customers. AReM states that any costs incurred by the utility in its long-term procurement are incurred solely for the benefit of bundled customers, and since customers

[43] See D.03-05-034, Finding of Fact 13.

that are currently eligible for direct access do not create stranded costs when they move to direct access, imposing the stranded cost NBCs on such customers would be inconsistent with the principle that costs should be allocated on the basis of causation.

In response TURN argues the potential for stranded costs resulting from load departing from the bundled portfolio is exactly what the relevant portions of D.04-12-048 were all about. Rather than "not seeing a need" to address the circumstances described in D.03-05-034, the Commission saw a need and addressed it by adopting the stranded cost NBC. TURN adds that AReM's further statement that: "any costs incurred by the utility in its long-term procurement are incurred solely for the benefit of bundled customers" proves TURN's point. Currently bundled customers who happen to be eligible for direct access are just that – bundled customers, the very people for whom the utility is incurring costs.

4.2.2. Discussion

We do not adopt AReM's request to confirm that bundled service customers who are eligible to return to DA should be exempted from the NBC associated with D.04-12-048. We generally agree with the responses by the IOUs and TURN as detailed above. None of the decisions cited by AReM specifically exclude these customers from the charge.[44] In D.04-12-048, we found that the

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[44] AReM is correct that D.03-12-059 finds: "Although Edison established a need for Mountainview, in order to not over-burden ratepayers in the early years of the contract, we adopt TURN's proposal that all customers of Edison that are currently ineligible for direct access be obligated to pay for stranded costs for the first 10 years of Mountainview's life." (Finding of Fact 22.) However, at the time of the decision, dated December 18, 2003 the relevant former DA customers who had returned to bundled

Footnote continued on next page

stranded costs should be recovered from all customers and did not indicate any exceptions. By our decision today, we have addressed the implementation of the D.04-12-048 NBC by employing the previously used principles of bundled customer indifference and customer responsibility for costs incurred on their behalf. We consider this to be logical and fair, and consistent with the principle of these customers paying their fair share for costs incurred on their behalf, and of preventing cost-shifting. We do not see such logic or fairness in AReM's request.

As described by AReM, there is a detailed process by which certain customers can return to DA service. However, until these customers return to DA, they are no different from the other bundled customers on whose behalf the IOUs are making procurement related decisions. Until the proper notice is given, the IOUs have no way of knowing if and when such customers will depart. The IOUs therefore properly include the related loads of the potential DA customers in their load forecasts. By doing so, the IOUs are procuring and making procurement commitments on behalf of these customers. As is the case with all other customers, these customers should be subject to the D.04-12-048 NBC for procurement commitments made on their behalf up until the date they provide notice to the IOUs of their intent to return to DA.

(*footnote continued from previous page*)

service would have been "currently" (as of the decision date) ineligible for DA, because of the three-year commitment obligation established by D.03-05-034.

4.3. Above-Market Standard Offers for New QF Contracts

In D.07-09-040, dated September 20, 2007, the Commission ordered that the utilities make standard offer contracts available to existing qualifying facilities (QFs) with expiring PPAs or to new QFs. PG&E argues that this requirement, similar to RPS and RA requirements, impacts utility procurement and creates uncertainty in resource planning, and to the extent the prices in the new QF standard offer contracts are above-market prices, bundled customers may incur additional stranded costs. In its opening brief, PG&E requested that the Commission, in this decision, affirm that stranded costs associated with these contracts can be recovered under D.04-12-048 or D.06-07-029.[45] In reply briefs, SCE agreed with PG&E's request. No other party replied on this topic.

We agree that the IOUs should be able to impose NBCs for the above market costs of these new QF contracts. This can be accomplished through the D.04-12-048 NBC, and we will authorize that NBC for this purpose. However, there has been no demonstration of need for cost recovery of these new QF contracts through the CAM that was authorized by D.06-07-029, and we will not do so. The CAM was designed to get new system reliability resources built and the resigning of QF contracts does not accomplish that. Even for contracts with new QFs, cost recovery under the CAM may not make sense due to the requirements and costs associated with the energy auction process.

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[45] Evidentiary hearings in Track 3 concluded on September 21, 2007. The opening brief was the first real opportunity for PG&E to raise this issue in this proceeding.

4.4. Other Applicability Related Issues that Will Not Be Addressed in this Proceeding

D.04-12-048 and D.06-07-029 established the NBCs at issue here in Track 3 of this proceeding. In general, Track 3 was intended to address implementation issues related to NBCs. That scope was modified slightly to include the issue of determining the fair share of DL liability of the new generation NBCs. Our obligation is to reconcile issues properly within the established scope. TURN's BNI proposal directly relates to this issue and we felt it necessary to address AReM's request for clarification. We also felt a need to address PG&E's request regarding the inclusion of new QF contracts, since it is relevant to the applicability of the NBCs at issue and came about because of our recent decision on the matter. However, there were also other issues that related somewhat to the applicability of NBCs which were identified and addressed by certain parties in the Track 3 briefing process. They include such things as:

- There is a lack of statutory basis for NBCs;
- Utilities should not be able to recover NBCs for procurement costs arising in the normal course of business;
- NBCs will "chill" combined heat and power and CGDL development;
- The benefits of CGDL justify an exclusion to the NBCs; and
- Imposition of the stranded cost NBCs on customers currently eligible for direct access would hamper retail competition.

While many of these issues may have been rendered moot by our resolution of the applicability of the NBCs as they relate to DL, they are also outside the scope of this track of the proceeding and will not be addressed in this decision. Such issues should be, or should have been, pursued in the proceedings that established the charges, not in this proceeding which was principally designed to implement the charges. To fully address such issues now

would not be fair to the parties that did not fully address the related arguments in briefs. Those parties, with good reason, assumed the issues were beyond the scope of the proceeding and treated them accordingly, and so shall we.

5. Framework for the D.04-12-048 NBC

The IOUs propose that D.04-12-048 NBC recovery should be implemented in the form of a surcharge based on the extent that certain generation resources are uneconomic and the costs may be stranded. To make that determination, the costs of the appropriate generation resources would be compared to a market benchmark. If the resource costs are greater than the market costs, the resources are considered uneconomic and a surcharge based on that difference would be imposed. Having a customer, who chooses an alternative energy supply, pay a surcharge that covers the uneconomic portion of the resource costs associated with that customer's departure will leave the bundled customer indifferent to the departure. This general framework is reasonable, and we will adopt it for the purpose of implementing the D.04-12-048 NBC, subject to our previous determinations regarding the applicability of the charges.

6. Implementation Issues for Cost Allocation Under D.04-12-048

Two principal implementation issues that have been identified in this proceeding relate to (1) whether the D.04-12-048 NBC should be determined in isolation (separate charge approach) or in conjunction with other resources and other related CRS obligations (total portfolio approach); and (2) the method by which new resource obligations are determined for specific customers considering when those customers depart or choose alternative energy providers (vintaging). We also address issues related to the cost-effectiveness and the actual calculation of the NBC in this portion of the decision.

6.1. Total Portfolio and Separate Charge Approaches

Under the total portfolio approach, the uneconomic costs associated with new generation resources[46] are determined in conjunction with the economic and uneconomic costs associated with older generation resources. Under the separate charge approach, the uneconomic costs associated with new generation resources are determined separate from that for older generation resources. In either case, new generation NBCs (based on either the total portfolio or separate charge approach) would be imposed in those years in which generation costs are shown to be uneconomic, that is higher than the market benchmark costs, and the NBCs would recover no more than those uneconomic costs for those years. New generation NBCs would not be imposed in those years where the generation costs are lower than the market benchmark costs.

6.1.1. Positions of the Parties

6.1.1.1. Total Portfolio

In a series of decisions in R.02-01-011 (the DA/DL CRS proceeding) and R.03-10-003 (the CCA proceeding), the Commission adopted CRSs applicable to DA, MDL, CGDL and CCA. As explained earlier, the components of the CRS include the ongoing CTC and the DWR power and bond charges. Also, for PG&E, DA and MDL are responsible for the ECRA, which recovers PG&E's bankruptcy-related costs.[47]

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[46] The total portfolio does not include contracts subject to the CAM adopted by the Commission in D.06-07-029.

[47] For SCE, the HPC was also included as part of the CRS; however, the HPC was paid off and is no longer a part of the CRS.

The total portfolio approach is used in determining the power charge indifference amount (PCIA), which is the DWR power charge element of the CRS. The revenue requirement of the total portfolio of resources, which includes the DWR contracts, resources subject to ongoing CTC and pre-restructuring resources not subject to ongoing CTC (primarily utility retained generation (URG)), are compared to market costs. If the total portfolio costs exceed the market costs, that difference represents the uneconomic or stranded costs. Dividing that difference by total bundled customer and departing customer usage results in an "indifference amount," which in this case is positive and represents what departing customers should pay in order that remaining bundled customers remain indifferent to their departure. The PCIA is then calculated by subtracting the ongoing CTC charge from the positive indifference amount. If the PCIA is positive, the amount collected through the PCIA is remitted to the DWR to reduce the bundled service customers' DWR power charge obligation, while the ongoing CTC amount would be credited to the Energy Resource Recovery Account (ERRA) balancing account. If the PCIA is negative, there would be no remittance to the DWR and the entire indifference amount would be credited to the ERRA.

If the total portfolio costs are lower than market costs resulting in a negative indifference amount, the customers' departure is economic. However, departing customers do not receive a credit on their bills for negative indifference amounts. Instead, negative indifference amounts can be carried over to offset future positive indifference amounts but are not eligible to be applied against any other components of the CRS.

To implement the D.04-12-048 NBC, SCE recommends using the existing CRS total portfolio approach for calculating an indifference amount except the

total portfolio would now also include new generation resources subject to the D.04-12-048 NBC. Also, customers' cost responsibility for new generation resources would vary depending on when the customers depart and which new generation resources were committed to on their behalf prior to their departure. The revenue requirement would have to be calculated for each vintage of the utility's total portfolio of generation resources and contractual commitments. In its annual ERRA proceeding, SCE will set forth its total generation revenue requirement for each vintage of departing load and will also identify the portion of it that relates to costs covered by Public Utilities Code Section 367(a) to enable the calculation of the ongoing CTC. The total generation revenue requirement for each vintage will then be added to SCE's allocated DWR power charge revenue requirement to determine the revenue requirement on which an indifference amount will be calculated. Those revenue requirements would be compared to the market costs benchmarks and indifference amounts and PCIAs can be calculated and charged for each vintage of total portfolios, similar to the existing CRS calculations, as described above.

SCE supports the total portfolio approach because it is simple and provides departing customers with the benefit of any below-market assets they leave behind by netting them against any above-market costs in the total portfolio (including commitments made after D.04-12-048 was issued).

The total portfolio approach is preferred by SCE, SDG&E, AREM, Hercules, Merced ID, and Modesto ID. However, both SCE and SDG&E indicate D.04-12-048 is ambiguous as to whether a separate charge should be used and request the Commission clarify its intentions in this proceeding. If a separate charge is used, SCE indicates it does not oppose PG&E's proposal. Also, SCE and SDG&E note that in D.07-05-005, the Commission resolved the issue of

whether negative non-bypassable charges reflecting below market costs of a utility's procurement portfolio should be carried over from one year to the next. However, while the Commission held that a negative indifference amount in a given year should be carried-forward to cancel out future positive indifference amounts,[48] SCE and SDG&E state the decision is ambiguous as to whether that netting of negative versus positive indifference amounts applies only as long as the PCIA, or the DWR indifference concept, is in place. SCE and SDG&E therefore request that the Commission clarify how long it intends the carry-forward of negative indifference amounts to apply.

TURN is concerned with the 10-year limitation on cost recovery for non-renewable resources and recommends that, in order to maintain bundled customer indifference, the total portfolio should include the lower cost pre-restructuring resources that are not subject to ongoing CTC treatment for 10 years, ending in 2010, to offset the effect of the 10-year limitation on NBC cost recovery for non-RPS resources. If that adjustment were adopted, TURN would support carrying over negative indifference amounts to offset positive indifference amounts in future years. SDG&E supports TURN's proposal to limit the time that pre-restructuring resources are included in the total portfolio. PG&E indicated that if the Commission does not adopt PG&E's separate charge proposal, it should, at a minimum, adopt the limitation on pre-restructuring resources proposed by TURN. DRA indicated that, while it agrees with PG&E's approach, it could also support TURN's proposal.

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[48] See D.07-05-005, pp. 18-21.

6.1.1.2. Separate Charge

Rather than employing the total portfolio approach, PG&E has proposed a separate charge approach, where the new generation resources subject to the D.04-12-048 NBC, and only those resources, are used when comparing resource revenue requirements to market costs. Any resultant positive indifference amounts would represent the uneconomic costs that departing customers should pay in order that remaining bundled customers remain indifferent to their departure. The resultant charges are separate from the ongoing CTC and DWR power charges which would continue to be calculated separately as part of the existing CRS.

If the separate charge results in below-market costs, i.e., a negative indifference amount, the departure of customers would be economic. Under PG&E's proposal, there would be no credit on the departing customers' bills to reflect the negative indifference amount. Also the negative indifference amount could not be carried over to offset future positive indifference amounts.

PG&E argues that the D.04-12-048 NBC is different than the ongoing CTC and DWR power charges in a number of important ways and there are a number of differences between the approaches which justifies its proposal. They are:

- First, the D.04-12-048 charges apply to prospective generation costs, unlike ongoing CTCs, which recover QF and utility-owned generation costs, and the DWR-related costs.

- Second, the D.04-12-048 NBCs have certain limitations that do not apply to ongoing CTCs and DWR power charges, such as the 10-year limit on recovery for nonrenewable resources, including both PPAs and utility-owned generation. The CTC and DWR-related charges are for the life of the contracts at issue.

- Third, the D.04-12-048 charges apply to "all customers," unlike ongoing CTCs and the DWR power charges for which the Commission has granted some limited exceptions. Because the D.04-12-048 non-bypassable charges differ from ongoing CTC and DWR power charges, the Commission determined that an "additional" non-bypassable charge was necessary.

DRA supports PG&E's proposed approach.

6.1.2. Discussion

The principle of bundled customer indifference is paramount in considering the total portfolio/separate charge issue. Again, bundled customer indifference means that bundled customers should be no worse off nor should they be any better off due to departing loads. To start, we must determine what the real differences are between the separate charge approach and the total portfolio approach. Based on what those differences are and how they are viewed when considering bundled customer indifference, we can determine our preference. We can then consider whether the D.04-12-048 NBC 10-year limitation on cost recovery for nonrenewable resources necessitates some kind of adjustment to maintain bundled customer indifference; and if so, what that adjustment should be.

6.1.2.1. The Handling of Negative Charges

In total, the resources and costs for determining the charges for the remaining ongoing CTC costs, DWR related costs and the costs for new generation resources authorized by D.04-12-048 are the same under the total portfolio approach and the approach that calculates the D.04-12-048 charge separate from the ongoing CTC/DWR power charge. As clarified during evidentiary hearing by SCE witness Jazayeri, at this point, the only difference

between the separate charge and the total portfolio approaches is how negative charges are handled in the calculations.[49]

If all the calculated charges were positive, the departing customer would pay the same amount under both approaches. The only difference would be that the total portfolio approach, which considers all of the resources and costs together, would result in one combined charge; while the separate charge approach would result in two charges - the combined ongoing CTC/DWR power charge and the separate D.04-12-048 charge, which when added together would equal the total portfolio charge.[50]

However, if one of the charges is negative, the separate charge and total portfolio approaches would result in different charges, at least initially. For example, if the combined ongoing CTC/DWR power charge for any particular year is negative and the D.04-12-048 charge is positive, the two approaches would yield different total charges for that particular year.

Under the total portfolio approach, the three charges are essentially netted against each other and the result may be positive or negative. If the combined amount is positive, the customer would pay the combined charge. If the combined charge is negative, the customer would not pay anything and the combined negative charge would be carried over for use in subsequent years.

Under the separate charge approach, the customer would not pay anything for the ongoing CTC/DWR power charge and the entire negative

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[49] SCE, Jazayeri, 11 RT 1442-1445.

[50] The total portfolio methodology does not apply if a customer does not pay the DWR power charges. (*See* D.05-01-035, p. 3; D.06-07-030, pp. 34-38; D.07-01-020, p. 5.)

amount would carry over for use in subsequent years. The customer would also separately pay the full amount of the D.04-12-048 charge. Therefore, in that particular year, under these circumstances, the customer would pay a higher amount under the separate charge approach. However, when looked at over a number of years, in situations where the ongoing CTC/DWR power charge is negative, the customer may essentially pay the same amount under either approach, since even under the separate charge approach, the negative ongoing CTC/DWR power charge, while not offsetting the D.04-12-048 charge in that particular year, can be used to offset positive ongoing CTC/DWR power charges in subsequent years.

The principal difference between the separate charge approach and the total portfolio approach occurs when the D.04-12-048 NBC charge for any particular year is negative. Under the separate charge approach, the customer would not pay a D.04-12-048 charge, similar to what would happen if the combined ongoing CTC/DWR power charges were negative. However, in contrast to the negative ongoing CTC/DWR power charges being carried over for use in subsequent years, the separate negative D.04-12-048 charge would not be carried over for use in subsequent years. That negative amount then could never be reflected in calculating the customer's charge. Under these circumstances, over time, the total of the two separate annual charges would diverge from the total of the annual total portfolio charges, simply because the negative D.04-12-048 charge is never accounted for in calculating charges -- not in the particular year in which it occurs, nor in any subsequent year.

The handling of negative charges was previously addressed in D.07-05-005. In that decision, we stated:[51]

> …By allowing for negative indifference amounts to be netted against future positive amounts, the goal of bundled customer indifference is preserved…
>
> …By recognizing only positive indifference amounts, but not tracking offsetting effects attributable to negative indifference, PG&E's proposed method could result in a permanent net positive indifference amount charged to DA/DL customers. The indifference charge is intended to capture the applicable above-market procurement costs. Indifference is achieved when there is neither an under-or-over recovery of such indifference charges from DA/DL customers..."
>
> …Therefore, in order to maintain indifference, both positive and negative indifference effects must still be tracked, with the negative amounts offsetting positive amounts…

While the Commission's reasoning in that decision applied to the existing DA/DL CRS calculations, the basic principles directly relate to handling of negative charges in this proceeding as described above. It is similarly necessary that negative indifference amounts be carried over for use in subsequent years to maintain bundled customer indifference. The total portfolio approach is consistent with this principle. PG&E's separate approach is not. While we could adopt PG&E's separate approach after first modifying it to conform to our previous determinations regarding the carryover of negative indifference amounts, we prefer instead to adopt the use of the total portfolio approach for

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[51] *See* D.07-05-005, pp. 18-19.

use in implementing the D.04-12-048 NBC. This preference is primarily based on our understanding of the implications of each approach with regard to the handling of pre-restructuring resources not subject to ongoing CTC, as discussed below. The use of the total portfolio approach is necessary to implement provisions of this decision regarding the use of these pre-restructuring resources in determining cost responsibility once recovery of the DWR power charge ends.

6.1.2.2. Pre-restructuring Resources not Subject to Ongoing CTC Treatment

One of PG&E's objections to the total portfolio approach is related to whether or how long the pre-restructuring resources[52] should be included in the portfolios for calculating ongoing CTC, DWR power charges and D.04-12-048 charges. PG&E argues that requiring new generation costs to be offset by generation that is 25 to 30 years into its depreciation cycle does not truly capture the stranded costs associated with the new generation, and departing customers should not receive the benefits of existing generation after they leave bundled service. By PG&E's separate charge approach, the pre-restructuring resources are not included in the calculation of the separate D.04-12-048 charge. Also, while PG&E acknowledges that currently these resources are reflected in the calculation of the PCIA, PG&E also states that the indifference standard and current total portfolio approach expire once the DWR power charge ends. When that happens, as a consequence of PG&E's separate charge approach for the

[52] For purposes of this decision, "pre-restructuring resources" refers to those current IOU resources that existed prior to March 31, 1998 and are not subject to ongoing CTC treatment. These resources consist principally of the IOUs' retained generation (i.e., hydro, coal and nuclear plants). Power from these resources tends to be cheaper when compared to the costs related to ongoing CTC, the DWR contracts and new generation.

D.04-12-048 charge, only the ongoing CTC would remain in the existing CRS calculation, effectively eliminating the use of pre-restructuring resources.[53]

SCE, in recommending the total portfolio approach, does not indicate that pre-restructuring resources should ever be excluded from the portfolio. SCE's statement that its proposal "provides the departing customers with the benefit of any below-market assets they leave behind by netting them against any above-market cost in the total portfolio (including commitments made after D.04-12-048 was issued)," suggests, to the extent contracts have not expired or generation assets are not yet retired, the pre-restructuring resources would remain in the portfolio as long as D.04-12-048 charges were being calculated and assessed. Similar to the current DWR power/ongoing CTC methodology, the total indifference amount would be calculated, the ongoing CTC portion would be calculated pursuant to Pub. Util. Code § 367(a), and that amount would be subtracted out of the total resulting in the D.04-12-048 charge.

In D.02-11-022, the Commission determined that a total portfolio approach was appropriate for use in calculating the DA CRS, stating:

> The intent underlying the indifference calculation, however, is to determine the cost shifting that resulted from the migration of certain bundled customers to DA. An accurate measure of cost shifting cannot be determined if we selectively focus only on certain

[53] Consistent with D.06-07-030, pre-restructuring resources cannot be used to mitigate the costs of ongoing CTC alone. In that decision, we stated "We thus conclude that applying a bundled customer indifference standard is not appropriate in deriving the cost responsibility for MDL customers if no DWR power charge is paid. We shall apply a total portfolio indifference standard to MDL CRS obligations only where a DWR power charge is applicable. The indifference adjustment does not change the ongoing CTC that applies uniformly to all bundled, DA and DL customers." (D.06-07-030, p. 37.)

> components of cost shifting while ignoring others. The directive in D.02-03-055 was to consider all cost shifting, not just those effects attributed to the DWR portion of the total portfolio. The netting of [utility retained generation] URG savings does not imply that those URG resources are somehow dedicated to serving DA customers. The attribution of savings to DA customers merely reflect the change in costs experienced by bundled customers associated with their use of those dedicated resources. (D.02-11-022, p. 25.)

That reasoning is directly applicable to our consideration of the D.04-12-048 charge. By including only the D.04-12-048 resources in the portfolio, the separate charge approach only considers cost shifting associated with those resources. Bundled customer indifference will only be maintained if all resources are included in the portfolio used to calculate the related charges, whether it is the ongoing CTC, DWR power charges and D.04-12-048 charges or just the ongoing CTC and D.04-12-048 charges. Therefore, the use of the total portfolio and the inclusion of the pre-restructuring resources in that portfolio is the appropriate approach to use for the duration of the D.04-12-048 NBC cost recovery[54] even after cost recovery of the DWR power charge ends.

Similarly, the current provisions related to negative indifference charge carryover for use in subsequent years should be continued once DWR power charge recovery ends. Again, this is necessary to maintain bundled customer indifference. D.07-05-005 did state that at the expiration of the DWR contract term, the applicability of the indifference requirement would also expire. That made sense in the context of that decision, since it was the recovery of the DWR

[54] The pre-restructuring resources would be included in the portfolio as long as they have not been retired.

contracts themselves that necessitated the total portfolio approach and bundled customer indifference as it relates to such recovery. With the expiration of the DWR contract term, none of this would have been necessary, and the applicability of the indifference requirement as it relates to DWR power charge cost recovery should also have ended. However, with the inclusion of D.04-12-048 cost recovery as part of the total portfolio, the reasons cited in D.07-05-005, as discussed above as to why negative indifference charge carryover is appropriate, apply even after expiration of the DWR contract term. That reasoning is as valid for cost recovery related to the ongoing CTC and D.04-12-048 charges as it was for cost recovery related to the ongoing CTC and DWR power charges.

6.1.2.3. The 10-Year Limitation on Cost Recovery Under D.04-12-048

As discussed below, we have considered the effects of the D.04-12-048 provision whereby cost recovery for non-renewable resources is limited to 10 years, and we do not feel it is necessary to make any related changes to the total portfolio approach at this time.

In D.04-12-048, the Commission concluded:

> The utilities should be allowed to recover stranded costs for their non-RPS resource commitments from departing load over either the life of the contract or 10 years, whichever is less. The ten-year recovery period should also apply to any utility-owned generation acquired as a result of the procurement process, commencing once the resource begins commercial operation. Stranded costs arising from RPS procurement activities should be collected from all customers, including departing load, over the life of the contract. The utilities should be allowed the opportunity to justify in their applications, on a case-by-case basis, the desirability of adopting a cost recovery period of longer than ten years for their non-RPS resource commitments. Cost recovery for that portion of a resource

> acquired by the utilities to meet local reliability needs should be recovered from all customers. (Conclusion of Law 16.)

Two proposals have been made to address the perceived effects of this 10-year cost recovery limitation. There is PG&E's separate charge approach which effectively abandons use of the supposedly cheaper pre-restructuring resources as soon as DWR power charge cost recovery ends. There is also TURN's proposal for use of a total portfolio approach which would include the pre-restructuring resources in the total portfolio only through 2010. In both cases, the resultant D.04-12-048 charge would likely be higher than it would be if there were no limitations on including pre-restructuring resources in the total portfolios. Both PG&E and TURN argue that their proposals are necessary to maintain bundled customer indifference with respect to the D.04-12-048 10-year limitation for cost recovery of non-RPS resources.

As support for its position TURN argues, "As long as new non-RPS resources can only be included for 10 years, consistency would dictate that pre-restructuring non-QF resources should only be included in the total portfolio for ten years as well. Otherwise, there is a bias in the calculation that interferes with the achievement of bundled ratepayer indifference on a total portfolio basis."[55]

However, the D.04-12-048 10-year cost recovery limitation is for each specific non-RPS resource. TURN's pre-restructuring resource limitation is not specific for each resource but is instead applicable to the total portfolio with a set end date of 2010. Since the DWR power costs are continuing and will likely not

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[55] TURN Opening Brief, p. 7. *See* also Exhibit 117, p. 13.

end until after 2010, the pre-restructuring resources would have been included in the total portfolio anyway to maintain bundled customer indifference in the calculation of the fully recoverable DWR power charge for that entire 10-year period. If a non-RPS resource begins providing energy in 2011, cost recovery of the related D.04-12-048 charge would extend 10 years through 2020. Yet under TURN's proposal, in the calculation of the related D.04-12-048 charges, the pre-restructuring resources would not be included in the total portfolio for any of those years. TURN's argument that a limitation on the use of pre-restructuring resources fairly offsets its perceived effects of the D.04-12-048 10-year limitation on cost recovery for non-RPS resources is not persuasive.

Similarly, while PG&E's separate charge approach has not been adopted by this decision, when its separate charge approach and existing CRS are looked at in total, pre-restructuring resources would also cease to be considered in determining these charges at a specific point in time. That would be when the DWR power charge ends. We see the same problems with that as we do with TURN's proposal to end the use of pre-restructuring resources in the total portfolio in 2010.

As indicated, we do not see the logic or fairness in ending the use of pre-restructuring resources in the total portfolio as of 2010 or as of the date that cost recovery for the DWR power charge ends as a way to address the D.04-12-048 limitation on cost recovery for non-RPS resources and will not do so.

With respect to non-RPS resources that will be available for more than 10 years but which are limited to 10-year NBC recovery, the utilities can, over time, adjust their load forecasts and resource portfolios to mitigate the effects of DA, CCA, and any large municipalizations on bundled service customer indifference. By the end of a 10-year period, we assume the IOUs would be able to make substantial progress in eliminating such effects for customers who cease taking bundled service during that period. Furthermore, as provided by D.04-12-048, uneconomic costs associated with new non-RPS resource contracts of 10 years or less are fully recoverable, and the uneconomic costs of new RPS contracts are fully recoverable over the length of the contract with no limitation.

We must also consider the possibility that for non-RPS contracts or utility resource assets with lives significantly longer than 10 years, there may be a point in time when such resources may become more economic, when compared to the market benchmark, than many of the other newer resources existing during that time period, and thus may in effect lower future total portfolio costs similar to

the manner in which the pre-restructuring resources currently have in lowering current total portfolio costs. The fact that such lower costs would also not be reflected in the total portfolio after the initial 10 year period may have an impact on the need to extend the length of time that certain resources should remain in the total portfolio.

However, if the IOUs believe a cost recovery period extension is appropriate and necessary for specific non-RPS resources, they can make such requests under the provisions of D.04-12-048. The Commission can then tailor its findings, conclusions and remedies to the specific facts of each case and can fully extend, partially extend or not extend the cost recovery period. We believe this process is fair and more reasonable than implementing some overall limitation on the resource portfolio mix.

6.1.2.4. RPS Resources

In a number of advice letter filings requesting approval of RPS power purchase agreements, PG&E included a request to recover the above market costs of the contracts through a NBC, consistent with its interpretation of D.04-12-048. The Commission consistently declined to do so, indicating that it would not address such above market cost recovery in the resolutions and indicated that R.06-02-013 was the appropriate procedural forum for addressing those issues.[56] In Resolution E-4138, dated December 20, 2007, the Commission clarified its intent as follows:

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[56] For example, see Resolutions E-4046, E-4047, E-4055 and E-4084, E-4110, E-4084, and E-4138.

> …by this resolution we make no determination of whether stranded costs will in fact be incurred during the life of this contract. However, to the extent that such costs should occur, such costs will be eligible for stranded cost recovery subject to any determination in R.06-02-013 or any other proceeding regarding the implementation of cost recovery provisions of D.04-12-048….

To further clarify, with respect to the implementation of the stranded cost provisions of D.04-12-048 that are addressed in today's decision, the NBCs, which include any above market costs related to RPS contracts, will not apply to departing load that is excluded from the load forecasts used to develop the IOUs' LTPPs. The excluded departing load includes MDL, with the exception of large municipalizations, and CGDL. DA and CCA load are fully subject to the D.04-12-048 NBC. Furthermore, RPS contracts are fully recoverable over the life of the contracts. When calculating the CRS, the RPS contracts will be blended in with other generation resources under the total portfolio analysis. The costs of all of the resources would be compared to the applicable benchmark price to determine whether there are any above market costs. The applicable benchmark price will be calculated as set forth in D.06-07-030 and modified by D.07-01-030. Also, since the D.04-12-048 NBC is based on a total portfolio analysis of an above-market price and is not intended to allocate specific resources to specific customers, none of the benefits or attributes of the RPS contracts will be transferred to those customers who pay the D.04-12-048 NBC at this time. We note, though, that future developments in the State's renewable and/or greenhouse gas policies may both necessitate and facilitate a review of the manner in which renewables attributes are treated with respect to departing load and the new generation NBC to best maintain ratepayer indifference and the State's various policy objectives.

6.1.2.5. Future Modifications

The D.04-12-048 NBC was established for a number of reasons including the uncertainty caused by potential increases in DA,[57] CCA and DL.[58] The need for the NBC is likely to be long lasting. Given the potential long-term nature of the charge, we must allow for the possibility that certain future circumstances may result in a need to modify the NBC related processes adopted in this decision.

For instance, SCE believes that the current methodology for determination of a market price benchmark is reasonable as long as the load departure does not increase significantly above that seen in the post-2001 period. If it does increase significantly, SCE indicates it may ask the Commission to revisit the issue.[59] SDG&E also states that it is not clear that the benchmark would be appropriate in the future should DA reopen or significant load migrates via CCA.[60] Significant

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[57] The potential increase in DA is dependent on the outcome of our proceedings regarding the lifting of the DA suspension. Our reference to this potential increase is not intended to prejudge the outcome of those proceedings.

[58] In D.04-12-048, the Commission stated, "A major issue in this proceeding is the extent to which the utilities will be compensated for investments or purchases that they must make in order to meet their obligations to provide reliable service to their customers. The implementation of CCA, departing municipal load, and the potential for lifting, in some form or another, the current ban on allowing new DA all create a great degree of uncertainty as to the amount of load the existing utilities will be responsible for serving in the future. Given the potential for a significant portion of the utilities' load to take service from a different provider, the utilities are concerned that they could end up over-procuring resources and incurring the stranded costs associated with these resources." (D.04-12-048, p. 55.)

[59] SCE, Exhibit 34, p. 14.

[60] SDG&E, Exhibit 51, p. 1.

shifts in load may affect other things such as the need for renewable contracts and how such contracts should be handled in the recovery of stranded costs.

If, due to future changing circumstances, the processes adopted by this decision for determining the NBC become unworkable, unbalanced, or unfair, parties may propose and request, for our consideration, modifications to the form of the NBC or the manner in which the NBC should be determined or calculated.

6.1.2.6. Summary

To summarize, we adopt the use of a CRS calculation using a total portfolio approach that accounts for the ongoing CTC, DWR and D.04-12-048 charges. This includes netting the individually calculated annual charges and carrying over any negative total charge to offset positive charges in subsequent years. Further, we determine that pre-restructuring resources should continue to be included in the portfolio of resources used in determining the D.04-12-048 charges, once recovery of DWR power costs ends. We will address the effects of the 10-year limitation on cost recovery of new non-RPS generation resources on bundled customer indifference, on a case-by-case basis, if and when the IOUs request cost recovery extensions, pursuant to the provisions of D.04-12-048. Finally, should the processes adopted by this decision become unworkable, unbalanced, or unfair, parties may request, for our consideration, modifications to the form of the D.04-12-048 NBC or the manner in which that NBC should be determined or calculated.

6.2. Vintaging

For this proceeding, we define vintaging as the process of assigning a departure date to departing customers in order to determine those customers' generation resource obligations.[61] To implement the stranded cost recovery principles adopted in D.04-12-048, the IOUs must track the generation costs, including the costs of certain generation commitments, incurred to serve departing customers up to the point when a particular customer departs and the IOU no longer provides procurement services to serve its load. The law permits the recovery of stranded costs from those customers who are responsible for stranded costs related to resource and contractual commitments made by the IOU up until the time of the customer's departure and that departing customers should bear no cost responsibility for such commitments the IOU makes after their departure. The determination of a departure date is extremely difficult, especially one that tracks customers by the day, the week or the month of departure and vintages them accordingly. Each of the IOUs has made an alternative recommendation to establish a departing customer's vintage, and certain other parties have indicated their preferences and recommendations on this issue.

6.2.1. Positions of the Parties

PG&E proposes annual vintaging. For example, if a customer leaves in 2009, it would be responsible for any stranded costs associated with new generation resource commitments made in 2009 and previous years, but would not be responsible for commitments made in 2010. PG&E states that its proposal

[61] Departing customers also include new MDL.

is consistent with its ERRA, which is forecasted on an annual basis. PG&E adds that its proposal reflects the reality that negotiating a new PPA or obtaining Commission approval may take some time, and that although the PPA may be executed or approved later in a calendar year after a customer departs, negotiations were started or the contract was submitted to the Commission for approval before the customer departed, on behalf of that customer and other bundled customers.

PG&E states that some parties have advocated shorter vintage periods, such as a six-month vintage. However, shorter periods will only add to the complexity of administering the D.04-12-048 NBCs. Under these proposals, within any given year there would be two or more classes of customers with certain vintages, requiring the tracking of when specific resource commitments were made and when customers left. Moreover, this proposal ignores the fact that a PPA may be executed or approved by the Commission later in the year, but was originally negotiated or submitted on behalf of the customer before it departed. PG&E notes the vintage period included in Modesto's Board approved NBC tariff is an annual vintage, which is what PG&E proposes here. PG&E concludes that the Commission should adopt PG&E's annual vintaging proposal because it is equitable and can be easily administered.

SCE proposes to vintage the departing customers by the calendar year in which they depart and on whether they depart in the first or second half of the calendar year. Customers leaving or providing SCE a binding notice of intent to leave in the first half of 2009 would be assigned a vintage that would include all the resources that SCE contracted for up through December 2008. For example, a customer that departs in April 2009 (first half of 2009) will be responsible for the stranded costs associated with utility commitments made through December

2008. However, a customer that departs in September 2009 (second half of 2009) will be responsible for the stranded costs associated with utility commitments made through December 2009. SCE adds that it should be understood that "the time a commitment is made" refers to when SCE executes a contract or begins the construction of a new generation resource, not when deliveries begin under the contract or the generation resource becomes operational.

SDG&E proposes the same vintaging methodology as proposed by SCE, indicating that while no single vintaging methodology is perfect for all situations, this is the fairest and most cost-effective methodology overall.

Hercules states that bundled customer indifference cannot be achieved if departing customers are held responsible for generation commitments made after their departure. As a result, Hercules prefers SCE's proposal (assigning vintage years to departing customers) to PG&E's proposal because, under SCE's proposal, at most a customer will be held responsible for generation commitments made up to six months after departure, compared to up to 12 months after departure under PG&E's proposal.

TURN indicates that while its bundled customer constituency would benefit from slightly greater stranded cost recovery under PG&E's method, SCE's approach strikes a better balance than does the PG&E proposal. TURN adds that if its other recommendations that are designed to insure bundled ratepayer indifference were adopted, it would support the SCE proposal on this issue.

DRA states that it supports SCE's and SDG&E's proposals adding that the Commission must craft a workable solution that balances the rights of departing load customers with the practicality of utility administration.

AReM notes that the Commission will be considering a broad range of issues related to a new retail market structure in its rulemaking concerning DA (R.07-05-025) and urges the Commission defer the development of a vintaging system for DA customers to that proceeding. However, if such a vintaging system is to be adopted in this proceeding, AReM recommends that DA customers should be assigned a vintage that corresponds with the month in which they provide notice to their utility of their intent to depart bundled service. AReM states that while, in theory, each customer should be assigned an individual "vintage" corresponding to the precise time that the customer gives notice of its intent to depart, it recognizes that this could impose a significant administrative burden, as it would require the NBCs for each customer to be calculated separately. Instead, AReM indicates that it would support a method that assigns a customer a vintage based on the month that a customer gives notice of its intent to depart bundled service, and in which customers who notify the utility of its intent to depart in a given calendar year are responsible for commitments made through June of that year.

Under AReM's proposal, customers who provide notification in January would pay for the stranded costs of up to six months of resource additions that were not made on their behalf, and customers who provide notification in December are exempt from the stranded costs of up to six months of resource additions that were made on their behalf. AReM argues that bundled customers would be left indifferent, since the overpayments and underpayments should, on average, cancel each other out, and there is no room for gaming, since a customer is never any better off for delaying his departure.

CCDC asserts that the vintage of DG customers is 2002 and, therefore, customers who install DG after 2002 should not be subject to stranded cost

recovery under D.04-12-048 or net cost allocation under D.06-07-029. CCDC argues that, for purposes of vintaging, load should be considered departing as of the date an IOU knew, or should have known, of the departure and notes the record in R.02-01-011 demonstrates that the IOUs had knowledge of DG departing load at least as early as 2001. It is CCDC's position that the IOUs should have continued forecasting DG departing load, the IOUs should be incorporating those forecasts into its procurement plans, the IOUs should not be procuring power for load they forecast will depart, and therefore the date of departure, or the vintage, for DG departing load, should be 2002. If the Commission does not set 2002 as the vintage for all CHP DG, then CCDC supports SCE's vintaging proposal.

Merced ID and Modesto ID similarly state that the Commission should confirm that the vintage of the transferred and new municipal departing load of Modesto ID and Merced ID is 2002 and, therefore, that the transferred and new municipal departing load of Modesto ID and Merced ID is not subject to stranded cost recovery under D.04-12-048 or net cost allocation under D.06-07-029. Merced ID and Modesto ID recommend that vintaging for non-exempt departing load should be based on SCE's proposal.

EPUC states that if no exemption is adopted for CGDL, the IOUs should use six month periods for vintaging purposes.

CCSF recommends there be at least two vintaging periods per year.

6.2.2. Discussion

The CCDC and the Merced ID/Modesto ID proposals that the vintage year for their customers should be 2002 are essentially based on the premise that forecasted load should be excluded from having to pay the new generation NBCs. This issue was addressed earlier in this decision. As discussed in

Section 4.1, MDL, with the exception of large municipalizations, and CGDL customers' fair share will be zero, and thus, they are excluded from having to pay the D.04-12-048 NBCs. The reason for the exemption is that these loads were excluded from the load forecasts used to develop the LTPPs. (See discussion above.) It is therefore unnecessary to address the 2002 vintage year issue.

We will not grant AReM's request to defer the development of a vintaging system for DA customers to R.07-05-025. Earlier in this decision, we determined that customers who are eligible to return to DA should not be excluded from having to pay the NBC associated with D.04-12-048. A vintaging methodology needs to be adopted now in order to determine the related cost responsibility, if and when such customers return to DA. If there are any vintaging related determinations made in R.07-05-025 that affect what is adopted in our decision today, we will consider modifications to today's decision, as necessary, at that time.

For DA customers, CCA customers,[62] and customers departing due to a large municipalization that is not reflected in the departing load forecasts, there are two general vintaging proposals as described above in the parties' positions. PG&E proposes that December 31st should be the assigned departure date for vintaging purposes for those customers departing in any particular year. Most customers would therefore have an assigned departure date that is later than the actual departure date. On the other hand, SCE proposes that customers

[62] An optional BNI process exists for customers choosing CCA. The departure date would be the CCA stated date on which the BNI is based. For those CCA customers who do not choose the BNI process, their departure date is when they cease taking procurement services from the IOU.

departing in the first half of the year would have a departure date for vintaging purposes of December 31st of the prior year, while customers departing in the second half of the year would have a departure date for vintaging purposes of December 31st of the year in which they depart. By this method, some customers will have assigned departure dates that are earlier than the actual dates, while others will have assigned departure dates that are later than the actual dates. As indicated above, this proposal is supported by a number of parties and is perceived to be fairer than PG&E's proposal.

First of all we agree that it is necessary to have some simplifying methodology so that the IOU does not have to figure out and administer the actual vintage for every customer.[63] However, in simplifying the process, most customers will have assigned departure dates that will not be the same as the actual date. The consequence of having a later than actual departure date is that the customer may end up being responsible for resource commitments made after that customer's actual departure (likely to benefit the remaining bundled customers), while the consequence of having an earlier than actual departure date is that the customer may end up not being responsible for certain resource commitments before that customer's actual departure (tending to be potentially adverse to the remaining bundled customers). Under PG&E's proposal, most

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[63] We agree with SCE's statement that "Ideally, departing customers should bear no cost responsibility for the resource and contractual commitments SCE makes after their departure. In practice, however, it is extremely difficult to track customers by the day, the week or the month of departure and assign them a CRS vintage. Vintaging based on calendar quarters could be done; however, it gets more and more difficult because you will have now four categories of customers to deal with instead of one or two. It

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customers will have assigned departure dates that are later than actual. This proposal would almost certainly benefit the remaining bundled customers in the long term. Under SCE's proposal there will be customers with assigned departure dates that are both earlier and later than actual. Over the long term, potential benefits and adverse effects to bundled customers would tend to balance out under this proposal. Consistent with our commitment to adhere to the bundled customer indifference principle where possible, we will adopt SCE's proposal to use two departure dates for vintaging purposes. We will also adopt SCE's related proposal that "the time a commitment is made" is when the IOU executes a contract or when the IOU begins the construction of a new generation resource, not when deliveries begin under the contract or the generation resource becomes operational. With regard to PG&E's concerns regarding complexity, the SCE proposal would still use annual electric revenue adjustment mechanism (ERAM) forecasts, and we do not see the process of assigning the vintage based on either the year in which the customer departs or the year before the customer departs (SCE proposal) as being any more complicated than assigning the vintage based on the year in which the customer departs (PG&E proposal). An assignment to a particular year needs to be done in either circumstance. Also, we are not persuaded to adopt PG&E's proposal for the stated reason that negotiating a new PPA or obtaining Commission approval on behalf of a departing customer and other bundled customers before the customer departs

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(*footnote continued from previous page*)

can go even monthly, but it just becomes an administrative nightmare." (SCE Opening

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may take additional time that is not directly reflected in the vintaging process. As indicated previously, we have adopted SCE's vintaging proposal which includes the identification of resource commitments that are made on behalf of departing customers based on when the IOU executes a contract or begins the construction of a new generation resource. That sufficiently covers the timeframe for departing customers' cost responsibility.

AReM's alternative proposal to use commitments as of June 30 for DA customers leaving bundled service in that year is similar to SCE's proposal in that, over time, the effect of customers having assigned departure dates earlier than the actual dates would be balanced by the effect of customers having assigned departure dates later than the earlier the actual dates. The only difference is that under AReM's proposal, DA customers departing in the first half of the year would have an assigned departure date that is later than their actual departing dates, while DA customers departing in the second half of the year would have an assigned departure date that is earlier than their actual departing dates. This is the opposite of SCE's proposal whereby customers departing in the first half of the year would have an assigned departure date that is earlier than their actual departing dates, while customers leaving in the second half of the year would have an assigned departure date that is later than their actual departing dates. Fairness and bundled customer indifference can be achieved under either approach. For consistency, we prefer to use one approach

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Brief, pp. 7-8; see also Exhibit 34, p. 11 and SCE, Jazayeri, 11 RT 1441.)

for all customers. Also, it is not clear what additional work would be involved in developing the June 30th, or mid-year, portfolios and the associated costs. The generation revenue requirement set forth in the ERRA proceedings and the allocated DWR power charge revenue requirements are generally determined on a full-year basis. For that reason, as well as the fact that it was preferred by a majority of the parties, we choose to adopt the SCE vintaging proposal over that of AReM.

The six-month proposal by EPUC appears to be similar to PG&E's proposal except the lengths of the vintaging periods are halved. There is still the problem of having most assigned departure dates being later than the actual departure dates. The six-month proposal would also add administrative burdens, since resource vintages and revenue requirements would also have to be determined on a six month rather than annual basis.

6.3. Calculation of the D.04-12-048 NBC

The D.04-12-048 NBC will be reflected as an element of the CRS as explained above. The new generation costs will be calculated annually by each IOU as part of the generation revenue requirement determined in its ERRA proceeding. The adopted DWR power charge revenue requirement is determined from the DWR revenue requirement allocation proceeding. With this information, the indifference amounts can be calculated. Since the calculation of the indifference amount requires both the adopted generation revenue requirement and adopted DWR power charge revenue requirement, each utility will submit the calculation of the indifference amount for each vintage of departing load in its advice letter implementing the later of the annual

ERRA decision or the annual DWR revenue requirement allocation decision, as is currently done.[64] Those advice letters will be reviewed by the Commission's Energy Division, but parties have the opportunity to protest the advice letter filings if they see a need to do so. Also, issues regarding consistency of the implementation and calculation of the CRSs with respect to this decision can be raised and litigated in the forecast phase of the IOUs' ERRA proceedings.

Examples of CRS calculations that include new generation charges are shown in Appendix E to this decision.[65]

6.3.1. Areas of Agreement

While all parties did not address all aspects of the calculation of the D.04-12-048 NBC and related CRS, there appeared to be a few areas where there did not appear to be any disagreements. They include (1) the use of the market benchmark adopted in D.06-07-030, as modified by D.07-01-030, to determine above-market costs and (2) the use of a forecast of costs, done through the ERRA, without an after-the-fact true-up. Both are reasonable and should be used in determining the D.04-12-048 NBC and related CRS.

Regarding the market benchmark, SCE believes that the current methodology for determination of a market price benchmark is reasonable as long as the load departure does not increase significantly above that seen in the

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[64] *See* D.06-07-030, pp. 22-29 and Exhibit 34, p. 15.

[65] These calculations are illustrative and not all-inclusive. For instance, it does not include a total portfolio calculation for MDL that may be subject to the DWR power charge but not the D.04-12-048 NBC. In practice, the IOUs will calculate the CRS in their Advice Letter filings, and parties can review them and protest as they see fit.

post-2001 period.[66] If it does increase significantly, SCE states that it may ask the Commission to revisit the issue, indicating that, in that case, it may be appropriate, for example, to calculate a mark-to-market for the utility portfolio for each calendar year (or smaller intervals such as each quarter) and assign the resulting stranded costs to all customers departing during that calendar year for all future years. SCE also cites Finding of Fact 38 of D.04-12-048, which recognizes that future development of liquid and competitive capacity markets and the implementation of the California Independent System Operator's Market Redesign and Technology Upgrade may warrant a modification to the adopted market price benchmark. SCE's concerns are legitimate. We will leave it to the parties to propose such changes, if and when they become necessary, in the proceedings where the market benchmark is calculated and used (e.g., the ERRA).

6.3.2. Levelized Fixed Costs

Based on the cross-examination of PG&E witness Winn on the cost recovery concept that, for a specific amount of utility plant, the accumulated depreciation is lower in the earlier years, and the associated net plant and fixed costs are therefore higher in the earlier years, when compared to the later years,[67] Merced ID/Modesto ID argue that the Commission should require that the IOUs should use a levelized calculation of the fixed costs of utility owned generation assets. Merced ID/Modesto ID suggests the Commission could have a

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[66] Merced ID/Modesto ID indicated agreement with this belief.

[67] PG&E, Winn, 10 RT 1215-1218.

workshop to address implementation of a levelized cost calculation. CCDC and EPUC make similar recommendations.

While the concept of levelized fixed cost recovery may be valid under certain circumstances, we will not deviate from normal capital cost recovery in this instance. As suggested by Merced ID/Modesto ID, CCDC and EPUC the fixed cost revenue requirement in the latter years of a project's life may be less than in the early years. This is principally due to the reduced rate base amount caused by the accumulated depreciation up until that time. However, in this proceeding we are dealing with stranded cost recovery that may last for 10 years while the project itself may have up to a 30-year life or more. Regarding the proposed levelized fixed cost recovery proposal, we do not feel it is equitable for customers who will only be paying for 10 years of the project's depreciation to be entitled to the entire reduced revenue requirement effect that results from the accumulated depreciation that will have been paid by other customers for 30 years or more. Therefore we will not adopt the levelized fixed cost recovery proposal for use in this track of the proceeding.

6.3.3. Determination of Capacity Adders and Line Loss Adjustments

EPUC also states a need for workshops related to the determination of capacity adders and line loss adjustments. However, EPUC did not explain what is wrong with either the values of these items or the way that these items are included in NBC calculation, or make any proposals to address any perceived shortcomings. No other party stated a need or recommended workshops for these purposes, and no party expressed agreement with EPUC in this regard. Such workshops have not been justified and will not be required by this decision.

6.4. Cost-Effectiveness

CCDC, Merced ID and Modesto ID have recommended that the Commission should evaluate the cost-effectiveness of the IOU's proposal for determining stranded costs, vintaging customers and calculating and imposing NBCs.

Also, Hercules states that no NBC should be billed to a departing load customer if the cost of determining, billing and collecting the charge exceeds the revenues to be collected. Hercules argues that without this limitation the IOU's bundled customers would be forced to pay more for billing and collecting departing load charges than the revenues would otherwise justify, thus violating basic principles of cost benefit.

6.4.1. ALJ Questions

While certain parties questioned the cost-effectiveness of the NBCs, no party provided any analysis or other evidence that would indicate whether or not the NBCs proposed by the IOUs in this proceeding were, or were not, cost-effective when comparing the costs of implementing and imposing the charges with the revenues that might be generated by such charges.

In order to address this issue, the ALJ requested the IOUs to provide the following:[68]

1. NBC related activities necessary to do the following:

[68] Draft questions were provided to the parties on September 19, 2007 and were discussed at the end of evidentiary hearing on September 21, 2007. Based on that discussion, certain changes were made, and the final questions were attached to the September 21, 2007 Reporter's Transcript (Volume 14).

a. Calculate the system average new generation NBC by vintage year or calculate the cost responsibility surcharge by vintage year.
b. Determine cost allocations.
c. Identify the customer.
d. Determine the customers NBC.
e. Bill the customer.
f. Collect and process a customer's payments.
g. Develop and maintain necessary tools and data base to perform items a. through f.

2. Estimates of the costs for each of the activities identified in response to Item 1 by cost center if possible. For Items 1.c. through 1.f. provide estimates of costs on a per customer basis.
3. For each cost identified in response to Item 2, an indication of whether the cost is a recurring or non-recurring cost. Include the frequency of recurring costs.
4. For each cost identified in response to Item 2, an indication of whether the cost is incremental to costs currently incurred by the utility or whether the cost is embedded in costs currently incurred by the utility.
5. Range of potential revenues that might be realized by imposition of an NBC, including that related to low, medium, and large usage customers, based on NBCs calculated using new generation costs or to total portfolio costs being 5% and 10% above the market price benchmark.
6. Conclusions and explanations of conclusions on the cost-effectiveness of imposing the NBC.
7. All assumptions and calculations related to 1 through 6.
8. Provide the information requested in Questions 1 through 7 for existing procurement related non-bypassable charges.

The intent of the ALJ's questions was to determine whether a reasonable forecast of revenues associated with NBCs could reasonably be expected to exceed the incremental costs of implementing and imposing the NBCs, which is generally the issue that was raised by the parties. There was no intention to

determine the cost-effectiveness of previously authorized and implemented charges such as the ongoing CTC or DWR power charge.

PG&E, SCE and SDG&E's response to the questions in Exhibits 211, 212 and 213 were filed on October 12, 2007. To allow parties the opportunity to comment on, or express concerns related to, the materials contained in the exhibits, a date of October 19, 2007 was set for the filing of responses to the exhibits. Responses were filed by CMUA, EPUC, Merced ID/Modesto ID, and CCSF.

6.4.2. Responses to the IOU Exhibits

According to CMUA, the information contained in the IOU documents should be afforded no more weight than that attributed to any response to a data request not subjected to cross-examination. CMUA states that neither PG&E nor Edison provides any supporting documentation or verification for their conclusions that the New Generation NBCs are cost effective. Rather, the IOUs' conclusions are based on an analysis that lumps together all classes of departing load – existing and potential – into one large group. CMUA argues that until such time as the IOUs respond completely to all the elements of the request, providing the Commission more comprehensive and detailed cost information, and until such information is subjected to additional examination and scrutiny, the Commission cannot conclude that the New Generation NBCs are cost-effective. CMUA urges the Commission to regard the IOUs' filings as merely the first step in addressing this issue, and as the initial basis upon which to develop a more detailed record.

EPUC states (1) SDG&E erred in describing past applicability of NBCs to customer generation departing load (CGDL); (2) SCE's filing does not show cost-effectiveness of application of the proposed NBC to CGDL; and (3) PG&E does

not provide a method for distinguishing between incremental load growth met with a direct transaction and normal course of business load changes or show how much it would cost the utility to distinguish between them. Additionally, according to EPUC, it remains unclear how a CGDL customer's standby service would be accounted for in determining this utility procurement departing load charge and whether the customer may essentially be charged twice for the same energy.

EPUC concludes that the IOUs' filings are inconclusive regarding the cost-effectiveness of applying a new procurement NBC on CGDL and further highlight the need for an exemption for these customers.

The primary concern Merced ID and Modesto ID have with the IOUs' cost-effectiveness exhibits is that they combine MDL with DA and CCA departing load. By applying the above-market assumptions to such a large potential departing load customer base, the IOUs overstate potential New Generation NBC revenues and understate the NBC collection costs potentially attributable to MDL. Additionally, Merced ID and Modesto ID state the IOUs' exhibits are superficial, contain errors and fail to fully respond to several of the questions.

Merced ID and Modesto ID request that the Commission (1) should require the IOUs to calculate potential New Generation NBC revenues for MDL only; (2) accord the IOUs' cost-effectiveness exhibits the weight of untested argument and use them only for the purpose of developing the scope of any further investigation it undertakes regarding the cost-effectiveness of any New Generation NBC; (3) consider findings in D.07-09-041 regarding PG&E's billing practices and findings in the Presiding Officer's Decision in Investigation 06-06-014 regarding manipulation of customer satisfaction data in SCE's Performance Based Ratemaking in deciding what weight to ascribe the

cost-effectiveness exhibits of each; and (4) recognize PG&E's admissions that (i) it is aware of POU annexation proposals, and (ii) it has the ability to adjust its load forecasts to reflect successful proposals.[69]

CCSF states there are significant issues of concern arising from the IOUs' responses, including the following:

- PG&E appears to overstate the nature of Commission approval of current NBCs;
- The IOUs appear to over-estimate the size of the potential departing load;
- PG&E asserts that the "overwhelming majority" of new municipal load will use PG&E gas service (implicitly assuming that all such developments will include gas as a service). Neither assumption is substantiated;
- PG&E's proposed use of such gas records, even where it may be possible, seems potentially improper;
- PG&E and SCE appear to give no response to ALJ Question 8; and

[69] In their Opening Brief, Merced ID/Modesto ID urge the Commission to undertake a further investigation into the cost-effectiveness of NBCs, including those implemented in connection with electric industry restructuring and the energy crisis, perhaps using Exhibits 211, 212 and 213 as tools in developing the scope of any such further investigation. They note that the Commission uses established tests from the California Standard Practices Manual: Economic Analysis of Demand-Side Management Programs (October 2001) to determine the cost-effectiveness of IOU programs from various perspectives, including ratepayers, society and program participants (here, departing load) and request that the Commission ultimately evaluate the cost-effectiveness of the proposed NBCs from all three perspectives.

- The responses generally seem to marginalize the incremental costs of these NBCs in a way that seems at odds with part of the IOUs' positions in litigation.

According to CCSF, the information cannot be deemed either accurate or reliable absent any test of its veracity, and the opportunity alone to offer comment is a poor substitute for time to review, opportunity to serve discovery and/or opportunity to cross-examine the proponents of the assertions at issue.

CCSF recommends the responses not be admitted as additional testimony, the exhibit numbers should be vacated and the submissions be identified as "Responses" with the express ruling that they are to be given the weight of untested argument only.

6.4.3. Discussion

In an October 23, 2007 ruling, the ALJ ruled that, in order to issue a timely decision for this track of the proceeding, the cost-effectiveness issue would not be pursued as far as having the utilities augment or correct their exhibits, providing parties the opportunity to conduct further discovery and prepare responsive analyses, or providing parties the opportunity to cross-examination the IOUs on information contained in the exhibits. The ALJ also acknowledged the concerns expressed in the parties' responses as described above. While the exhibits were received into evidence, it was indicated that they would be weighed accordingly and that the value of the information in determining the cost-effectiveness of NBCs either generally or for a specific type of departing load is therefore limited. It is with this understanding that we now address this issue.

If new generation costs or total portfolio costs were 5% to 10% above the market price benchmark, the information provided by the IOUs demonstrates that imposition of the new generation NBCs would be cost-effective when

analyzed on an incremental basis. For example, PG&E indicates that its costs to implement the D.04-12-048 NBC include a one-time billing system upgrade cost of between $5.8 and $7.5 million and recurring annual costs of approximately $23,331 per year. The revenues, which would be fully credited back to bundled customers to off-set above market generation costs, could be between $7.1 million a year (5% incremental departing load and 5% above market benchmark) and $28.5 million a year (10% incremental departing load and 10% above market benchmark) a year. PG&E states that over a 10-year period, this could result in revenues between $71 million and $285 million, depending on market conditions and departing load. SCE indicates most costs are embedded and quantifies incremental costs of between $200,000 to $1,200,000 to develop and maintain systems and data bases.

SCE estimates potential annual revenues of approximately $25 million (5% above market benchmark) and $50 million (10% above market benchmark). SDG&E estimates a potential range of yearly revenues of between $854,835 to $6,786,076 (assuming a total portfolio cost that is 5% and 10% above the 2007 market benchmark, allocated to a range of incremental departing load forecasts of 4% and 8%).

SDG&E indicates that implementation of tools and data bases would be a one-time cost of approximately $85,000 and determining the customers NBC would be a one time cost per account of approximately $2. According to SDG&E, there are no incremental costs associated with most of the other activities.

As explained earlier, the information provided by the IOUs was not subject to cross-examination. Whether certain costs are reasonable or are correctly classified as recurring, non-recurring, embedded or incremental is an

issue that will not be resolved in this proceeding. Also, the IOUs' analyses could not and did not consider our resolution of the issue related to the applicability of the charges discussed earlier in of this decision. However, the description of the activities and, when provided, the quantification of costs appear to be in a reasonable range. What we conclude from this information is that potentially there is a substantial amount of revenue at stake in the new generation NBCs and at least under certain circumstances (e.g., CCA, large municipalizations and the potential for reopening direct access) the overall incremental revenues generated by the D.04-12-048 NBC would likely more than offset the overall incremental costs of implementing the NBC. In order to capture any revenues associated with the NBCs, the necessary costs to implement the charges must be incurred. In light of potentially significant amounts of new generation NBC revenues, it is reasonable to incur such charges. We make this finding with the understanding that undertaking any detailed cost-effectiveness analyses[70] for these particular NBC charges at this time would be a speculative and not a particularly revealing exercise. That is because the costs for future new generation resources, the future market benchmark prices and the future amounts of load shifting caused by DA, CCA, MDL and CGDL would be the principal elements in any such analyses, and are generally unknown at this time.[71] It is also for these reasons that we will not pursue the cost-effectiveness issue any further in this proceeding.

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[70] For instance, some parties insist the analyses should be done separately by type of customer (DA, CCA, MDL and CGDL).

[71] We note that at this point it is not cost effective to set up and implement an NBC for MDL and CGDL customers, because at this point they are excluded from having to pay

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For the same reasons, once the charges are in place, it is reasonable for the IOUs to collect the NBCs without continually having to demonstrate cost-effectiveness for particular charges for particular customers.[72]

6.5. Additional Issues

6.5.1. Limit on NBCs

Merced ID/Modesto ID state that it is possible that the level of stranded cost recovery and/or net cost allocation mechanism NBCs will be unreasonably high and recommend that the Commission evaluate these NBCs on an annual basis and determine whether it is appropriate to establish and implement a cap.

The Merced ID/Modesto ID assertion regarding the possible high level of stranded cost recovery is very general and not supported by any specific basis or reasoning. Prior to the costs of any of these new generation resources being included in the revenue requirement and being eligible for stranded cost recovery, the Commission will have already examined both the need and costs of

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the charges, once these customers depart. There would be no revenues to offset any incremental costs. However, in the event that a large municipalization occurs, having procedures authorized and in place will facilitate the imposition and collection of potentially significant amounts of NBCs. The same can be said for significant amounts of CCA should they occur. Also, while there may be some DA activity at this time related to customers returning to DA service, significant amounts of activity and significant amounts of NBCs may result in the event that DA is reopened.

[72] We also note that even if the D.04-12-048 NBC were somehow demonstrated to not be cost-effective for certain customers, imposing their departing load costs on bundled customers would be contrary to the general principle against cost shifting. The maintenance of bundled customer indifference to that departing load would have to be addressed in some other manner.

the projects. We do not anticipate that our processes will result in unreasonably high levels of stranded cost recovery. It is not necessary to establish an annual procedure to determine whether it is appropriate to establish and implement a stranded cost recovery cap.

6.5.2. Cost Recovery Period for non-RPS PPAs

With respect to PPAs for non-RPS commitments, Merced ID/Modesto ID and CCDC interpret the D.04-12-048 provision that the IOUs should be allowed to recover any stranded costs that may arise over either the life of the contract or 10 years, whichever is less, to mean stranded cost recovery should begin when the PPA is signed, not when the project commences operation. We do not agree with that interpretation. From the time that the PPA is signed to the time the project commences operation, there are generally no payments being made. Essentially all costs to the IOU and the associated cost recovery from customers will begin with the commencement of operation of the project, and that is when the 10-year cost recovery period should begin.

For example, departing DA load in 2010 will be required to pay for nine years for a non-RPS resource that begins commercial operation in 2009, but for a non-RPS resource that is contracted for by the IOU in 2008 and will begin commercial operation in 2013, this customer will owe NBCs related to this resource from 2013-2022.

7. Framework for the D.06-07-029 NBC

For each new generation resource subject to the CAM adopted by D.06-07-029, there is also an associated annual revenue requirement or cost that must be recovered from ratepayers to make the IOUs whole for their investments. In this case, that cost is the total annual resource cost less the revenues that would be obtained through an energy auction. The remaining net

cost is an approximation of the capacity value of the resource and equals the cost of the associated RA credits. The RA credits have value in that they can be used to satisfy certain Commission RA requirements.[73] [74] Bundled customers will be indifferent to the choice of a customer to use alternative energy supplier, if the IOU charges the customer an NBC associated with that customer's share of the annual net resource cost and assigns the associated RA credit to the customer. This is accomplished in D.06-07-029 as follows in the adopted proposal:

> 15. The IOU should charge the benefiting customers the net cost of capacity, determined as a net of the total cost of the contract minus the energy revenues associated with dispatch of the total contract. All RA counting benefits and net costs are spread to the LSEs whose customers are allocated costs based on share of 12-month coincident peak, adjusted on a monthly basis to facilitate load migration. The contract costs paid and RA benefits received by DA (or CCA and muni load) and bundled customers should be based on a share basis equal to the credit share received. (D.06-07-029, p. 31.)

As described above, customers who choose DA or CCA will be assessed a NBC for the net cost of capacity, and the LSE to which they migrate will receive the related RA credits.

MDL, with the exception of large municipalizations, and CGDL have been excluded from having to pay the D.06-07-029 NBC, as discussed in Section 4.1 of

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[73] As PG&E states, "CAC/EPUC is correct that distributed generation is not a load-serving entity and is not required to meet the Commission's RA requirements. However, the RA credits allocated to departing distributed generation customers are valuable. Because Load-Serving Entities (LSEs) need to satisfy annual and monthly RA requirements, these departing customers may be able to sell or transfer these credits to LSEs that have an RA deficiency." (Exhibit 18, pp. 14-15.)

this decision. However, in the future, if any costs and RA credits are allocated to large municipalization customers, the adopted proposal in D.06-07-029 and the adopted implementation details in D.07-09-044 are not clear as to what these departing customers are supposed to do with their allocated RA credits. Per the guidance provided in D.07-12-052, the IOUs are not to be procuring system reliability resources on behalf of POUs, and CGDL customers are not LSEs. There is no direct use of RA credits for these departing customers. It appears they would be directly billed for the costs through a NBC and given the associated RA credits, possibly to resell to an LSE who has use for such credits. We will modify this outcome slightly as described below, to lessen the individual departing customer's burden of reselling the credits.

Bundled customer indifference can be achieved by placing a value on the RA credit and having the IOU net that amount out of the NBC and letting the IOU maintain that RA credit for its use. The departing customer would be responsible for any uneconomic costs which in this case are represented by the total annual PPA cost, less energy auction revenues, less the value of the RA credit. We will apply this procedure to any large municipalization customers to which the D.06-07-029 net cost NBC may apply.[75] By this decision, these DL

(*footnote continued from previous page*)

[74] A value of the RA credit could be determined by analyzing the ongoing market transactions for such products.

[75] To the extent that new WAPA departing load and split wheeling departing load customers are subject to the D.06-07-029 NBC and have no use for RA credits, this procedure should also apply.

customers will not receive the RA credit associated with their departing load and will not be responsible for the market value of the RA credit. However, they will still be responsible for any uneconomic costs, and bundled customers will remain indifferent to their departure.

8. Implementation Issues for Cost Allocation Under D.06-07-029

PG&E, SCE, SDG&E and TURN refer to D.07-09-044 wherein the Commission adopted an uncontested settlement that specified the principles for the D.06-07-029 energy auction and the implementation details for the corresponding allocation of benefits and costs,[76] and indicate nothing further needs to be done on this subject in this proceeding.

While most other parties are silent on this matter, AReM proposes certain modifications as discussed below. Also, EPUC raises a number of issues pertaining particularly to CGDL customers and states that they must be addressed, if the Commission does not exclude all CGDL from having to pay the D.06-07-029 charge. They include the following:

- Determination of a "capacity factor" exemption for qualifying CGDL;
- Determination of allocation method for RA credits to individual CGDL customers;
- Establishment of mechanisms to guard against "double-billing" CGDL customers that also take standby service by the IOUs;

[76] Unlike the D.04-12-048 NBCs, D.06-07-029 costs are not costs that are factored into and recovered through the total portfolio methodology.

- Establishment of mechanisms to guard against mistaken billing of load that is exempt from the definition of departing load (e.g., normal course of business load changes, back-up generation); and

- Regarding PG&E's proposal that CGDL customers "re-sell" the allocated but not needed RA credits, determination of identification methods for "purchasers" of RA credits.

Since we have essentially excluded all CGDL from having to pay both the D.04-12-048 and D.06-07-029 NBCs, as determined earlier in this decision, we need not address these issues at this time. However, we do note that consideration of the "capacity factor" exemption is beyond the scope of this track of the proceeding; there has been no demonstration that an allocation method for RA credits to individual CGDL customers does not already exist; the need to establish mechanisms to guard against "double-billing" CGDL customers that also take standby service by the IOUs and to guard against mistaken billing of load that is exempt from the definition of departing load has not been demonstrated; and the determination of identification methods for "purchasers" of RA credits is not necessary due to the manner in which this decision handles such credits.

8.1. Use of the DA CRS

In order to minimize the administrative burden associated with implementing the D.06-07-029 NBC, AReM recommends that, for DA customers, the charge be collected through the existing DA CRS. AReM does not provide any details on its proposal, and its intentions are not clear. If AReM is proposing that the D.06-07-029 costs be included with other utility procurement costs similar to the total portfolio approach adopted for the D.04-12-048 cost allocation, PG&E would oppose this proposal. PG&E argues that (1) the D.06-07-029 CAM

is unique in that it allocates both benefits (i.e., RA credits) and costs and (2) any proposal to blend the D.06-07-029 costs with other stranded costs is contrary to the express terms of the settlement, which AREM signed on to as a settling party.[77]

8.1.1. Discussion

The D.06-07-029 NBC is distinct from the elements of the DA CRS in that the charge itself is based on a cost that is net of the energy value, and there are associated RA credits. If and how those elements would be included in a charge that is based on a comparison of the costs of the energy and capacity of the IOUs resources to a market price benchmark is not explained by AReM.

Also, as explained in the principles for the energy auction process and products:

> 4. Net costs shall be calculated and determined separately for each Energy Auction PPA, and net costs shall not be netted against or in any way impacted by the costs of other resources in the utility's resource portfolio.[78]

The DA CRS and the D.06-07-029 NBC should therefore be calculated and billed as separate items.

8.2. Inclusion of the Charge under the DA CRS Cap

AReM recommends that, in order to prevent the NBCs from imposing an undue economic burden on DA customers and acting as a further drag on the DA market, the Commission should include the NBCs under the 2.7 cent per

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[77] PG&E Reply Brief, pp. 37-38.

[78] D.07-09-044, Appendix A, p. 22.

kilowatt hour (kWh) cap for the DA CRS established in D.02-11-022 and affirmed in D.03-07-030. SCE and PG&E oppose the recommendation.

SCE states that AReM's proposal is procedurally improper. According to SCE, presenting this proposal for the first time in Opening Brief deprives other parties of their due process rights. SCE further notes that, for PG&E and SDG&E, the 2.7 cent per kWh DA CRS cap is no longer in effect because they have already recovered their DA CRS undercollection, and for SCE the cap is expected to be eliminated by the end of 2008. Also, DA customers' LSEs will receive RA capacity credits in exchange for paying this NBC. This will allow them to reduce the cost of procuring capacity for DA customers and their corresponding charge to DA customer for such capacity.

PG&E states that there is nothing in the settlement that the Commission recently approved that would support capping the D.06-07-029 costs, and AReM should have proposed a cap in the settlement if it believed this was an important issue. PG&E also states that capping the net costs that could be allocated to DA customers would result in bundled customer bearing a greater share of the burden of the new generation costs, unfairly shifting costs to bundled customers. Also, since AReM suggests capping the costs, but not the allocation of the RA benefits, PG&E argues that DA customers should not be allowed to receive the full RA benefits of the D.06-07-029 cost allocation mechanism while only bearing a limited amount of the costs.

8.2.1. Discussion

We agree with SCE's statement that AReM's proposal is procedurally improper. AReM could have, and should have, made this proposal in its prepared testimony, not in Opening Briefs. However, we will address it at this

time. Having to consider other parties' due process rights is obviated by the fact that AReM's proposal is rejected.

First of all, the 2.7 cent/kWh DA CRS caps will have expired for all three IOUs by the end of 2008. Without a more definitive showing of need, we are reluctant to reinstate such caps, at any level, along with the necessary procedures for recovery of undercollections. Furthermore, the ESPs will be receiving RA credits. They should pay for such credits as they are received and used, not on some deferred basis. The need and equity of AReM's proposal has not been demonstrated, and it will not be adopted.

8.3. Five-Year Limitation

The adopted CAM in D.06-07-029 specified in part:[79]

> 2. New generation approved by this Commission and eligible for the cost allocation mechanism will receive cost recovery for a period of up to 10 years. We limit the maximum term of any cost paid by all customers to the term of the contract, or 10 years, which ever is less, from the time that the new unit comes online.
>
> 3. We intend this cost allocation mechanism to be in place for the term of the contract or up to 10 years, whichever is less, from the time the new unit comes on line. However, the mechanics of this cost allocation mechanism may change depending on the new market-based system which may evolve.

Rather than using the adopted cost recovery period of up to 10 years, AReM recommends that the Commission limit application of the CAM (or any similar ratemaking mechanism it may adopt for such purposes) to five years. AReM cites cross-examination testimony in a previous track of this proceeding, which indicates the utilities' long-term procurement plans are sufficiently

flexible to allow them to adjust their portfolios to accommodate significant changes in load within a few years, and asserts the shorter five-year period would be adequate to avoid any cost shifting. PG&E, SCE and SDG&E oppose the five-year limitation.

PG&E states that the fact that the utility can adjust the amount it procures does not eliminate the above-market costs it must pay for contracts it has already entered into on behalf of the benefiting customers, and argues that AReM's proposal to limit the D.06-07-029 cost allocation mechanism to five years would result in remaining bundled customers bearing a disproportionate share of the costs for new generation associated with long-term contracts, which will typically be 10 years or longer.

SCE states that AReM offers no legitimate reason for disrupting the careful balance the Commission achieved in D.06-07-029 (and on which SCE relied in entering into power purchase agreements for new generation resources) and that AReM's attempt to reduce the cost recovery period should be rejected.

SDG&E state that AReM's proposal contradicts the Commission's ruling in D.06-07-029 that the recovery period be up to 10 years, and that, with respect to AReM's argument that the IOUs' procurement activities are flexible enough to allow for a five-year recovery period, the Commission considered that argument in D.04-12-048 and concluded that a 10-year period was justified.

(*footnote continued from previous page*)

[79] D.06-07-029, p. 27.

8.3.1. Discussion

AReM argues the IOUs' long-term procurement plans are sufficiently flexible to allow them to adjust their portfolios to accommodate significant changes in load within a few years. AReM bases its argument on cross examination of utility witnesses in another track of this proceeding, where such flexibility was acknowledged. However, that examination related to increased DA load only. In the context of the CAM, DA load planned for by the IOUs includes existing DA load as well as increased DA load. Also, the IOUs must continually take into account ongoing MDL and CGDL in their procurement activities and may have to make further adjustments for potential CCAs or large municipalizations. AReM does not address the manner in which the IOUs would adjust their procurement when faced with all of these possibilities or whether any of the adjustments might result in additional costs that would be borne by bundled customers only. Also, it is one thing for the IOU to be able to adjust it's portfolio to accommodate significant changes in a short period of time in terms of physical energy purchases, however, it is quite another to do so in a manner that would result in bundled customer indifference. There is insufficient justification for modifying the length of the CAM as adopted in D.06-07-029, and we will not adopt AReM's request to do so.

9. Comments on Proposed Decision

The proposed decision (PD) of the ALJ 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 August 11, 2008 by PG&E, SCE/TURN, AReM, CCDC, California Large Energy Consumers Association (CLECA)/California Manufacturers and Technology Association (CMTA),

CMUA, EPUC, Merced ID/Modest ID, and Northern California Power Agency (NCPA).[80] Reply comments were filed on August 18, 2008 by PG&E, SCE/TURN, SDG&E, AReM, CCDC, CMUA, CCSF, DRA, EPUC, Merced ID/Modest ID, and NCPA.

To the extent that the comments merely reargued the parties' positions taken in their briefs, those comments have not been given any weight. The comments which focused on factual, legal or technical errors have been considered, and, if appropriate, changes have been made. Our consideration of comments related to the more controversial issues is summarized below.

9.1. Applicability of the NBCs

PG&E states that there is no evidence that the adopted load forecasts in this proceeding reflect MDL and CGDL. The PD discussion related to the applicability of the NBCs, has been revised to reflect the fact that the load forecasts adopted in D.07-12-052 are based on the CEC's 2007 IEPR Demand Forecast and to explain the evidence that supports the finding that loads associated with MDL (with the exception of large municipalizations) and CGDL are forecasted to depart and therefore are not included in the CEC load forecasts that were adopted in D.07-12-052 as the forecasts on which new generation needs are to be based in the LTPPs.

SCE and TURN state that the PD never explains why MDL and CGDL that are forecasted years after new generation resources have been acquired should benefit from the stranded cost reduction that increased load or flexibility in

[80] On August 18, 2008, NCPA filed a motion for party status. There were no responses, and the motion is granted.

procuring resources of various terms can bring about. The PD has been expanded to explain that even for these resources, at the time the resource commitments are made, (1) the LTPP load forecasts exclude forecasted amounts of MDL and CGDL; (2) these customers will eventually become the departing customers for which those amounts of MDL and CGDL are forecasted; and (3) therefore, in effect, these customers' loads are only reflected in the LTPP load forecast for the years in which they are bundled service customers. Therefore, (1) the IOUs' procurement needs related to these customers are only identified and planned for in the years in which they are bundled service customers; (2) the IOUs' procurement commitments are made on behalf of these customers only for the time that they are on bundled service; and (3) these customers' fair share of the costs related to these resources should be zero after they depart.

SCE and TURN express concern with the PD statement that the fair share of customers in a "large municipalization" may be zero because the large municipalization was foreseeable. We have reconsidered and removed this statement explaining that such customers have NBC cost responsibility for those resources procured on their behalf prior to the date of their departure or prior to an appropriate alternative date for ending cost responsibility for new generation resources such as that related to a BNI. Such customers' fair share can be zero only for those resources procured after such dates. We also agree with the assessment of SCE and TURN that a BNI process is a reasonable and preferable means for establishing when the IOU should have known about departures related to a large municipalization and should have excluded them from its load forecasts. However, we do provide an opportunity for the large municipalization entity to propose and justify an alternative date for determining the end of cost responsibility for new generation resources that is

neither a BNI date nor the actual departure date. The burden would be on the municipal entity to justify why the alternative date is more appropriate than what would be established in a BNI process.

PG&E argues that large municipalizations should be treated no different than DA and CCA and that calculating the fair share owed by each large municipalization on a case-by-case basis (by application) is inappropriate. We disagree. It is necessary that the affected IOU demonstrate on a case-by-case basis that the related annexation cannot reasonably be assumed to have been reflected as part of the historical MDL trends used in developing the adopted LTPP forecasts. Also, there may be a reason why a large municipalization should have a date for determining the end of cost responsibility for new generation resources that is neither a BNI date nor the actual departure date. An application process is a fair way to resolve these potential issues and we will not change the PD in that regard.

PG&E states that it should be made clear that NBCs also apply to New WAPA Departing Load and Split Wheeling Departing Load, consistent with D.06-05-018 and D.03-09-052. There were no replies to this comment. In its testimony, PG&E included such loads as being subject to the D.04-12-048 NBC (Exhibit 7, p. II-5). No party proposed such loads should be excluded from that charge. Similarly, no party proposed such loads should be excluded from that subject to the D.06-07-029 NBC. Consistent with D.06-05-018 and D.03-09-052 which assigned generation related NBC cost responsibility for new WAPA departing load and split wheeling departing load, we agree with PG&E's claim that such departing load should be subject to the D.04-12-048 and D.06-07-029 NBCs. The PD has been modified accordingly.

9.2. The D.04-12-048 NBC

PG&E and SCE/TURN continue to object to the 10-year cost recovery limitation for non-RPS resources. In general they believe that bundled customer indifference is violated by this limitation, especially since the PD would leave lower cost pre-restructuring resources in the total portfolio for the entire life of such resources. SCE and TURN urge the Commission to remove the 10-year limitation. PG&E argues all resources should be allowed in the total portfolio over the entire term of the PPA or life of a utility owned generation asset, or the inclusion of the pre-restructuring resources should be limited, in a manner previously recommended by TURN.

We are not convinced that the PD should be modified in this regard. First, PG&E, SCE and TURN apparently assume the resources in question will be uneconomic not only over the initial 10-year period, but over a substantial amount or perhaps the entire amount of the remaining PPA term or utility asset life. That may or may not be the case, depending on the economics of the specific resource. Second, by D.04-12-048, the IOU has the opportunity to request extension of the cost recovery period on a case-by-case basis. While this does not provide the certainty that the SCE/TURN or PG&E proposals do, we are convinced that it is a fair way for the Commission to review what the IOUs have done over time to mitigate potential stranded costs, what effect unlimited cost recovery for RPS contracts and 10 year or less non-RPS contracts has on overall stranded costs, and what the long term economics of the resources in questions are over time compared to that of other resources in the total portfolio. With that review, the Commission can make a better determination of the need to extend

cost recovery periods in order to maintain bundled customer indifference over time.[81]

10. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and David K. Fukutome is the assigned Administrative Law Judge in this phase of the proceeding.

Findings of Fact

1. It is reasonable to use the bundled customer indifference principle as well as the principle that stranded costs should be recovered from those customers who benefited from the stranded asset, in reconciling issues related to the implementation of the D.04-12-048 and D.06-07-029 NBCs.

2. The notion that each customer pay its fair share of the costs the IOU incurred on behalf of this customer or the load associated with this customer is an integral part of the principles of bundled customer indifference and prevention of cost-shifting.

3. In this proceeding, it is reasonable to apply the rule: when costs are incurred on its behalf, that customer must pay its fair share of the costs, and the corollary rule: if no costs are incurred on its behalf, then the customer's fair share can be determined to be zero.

4. Whether or not departing load should be forecasted and reflected in the IOUs' load forecasts is not an issue in this track of the proceeding.

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[81] We do not expect to see such requests for every resource with an expected term or life exceeding 10 years. While it is up to the IOU to decide whether and why an extension for a particular resource is necessary, it bears the burden to justify the request in terms of the factors discussed in this decision.

5. The structure of the load forecasts used in developing the LTPPs has already been addressed in Track 2, and any related issues have been reconciled in D.07-12-052.

6. It is reasonable and necessary to examine the implications of forecasted departing load on the applicability of NBCs, to ensure bundled customer indifference and the proper alignment of benefits and cost responsibility, which will be based on a determination of the fair share of the departing load for these NBCs.

7. For the three IOUs, system need is not impacted by possible future load shifting due to DA and CCA, and future CGDL and MDL are captured by historical trends used to develop the load forecasts.

8. The use of historic information and trends to reflect future departing load reduces some risk to the IOUs of possibly adopting overly optimistic estimates and tends to limit the dispute and litigation related to what the appropriate levels of departing load should be.

9. For IOU customers that are eligible to, and do, choose DA service from an ESP and for customers that decide to use a CCA, their loads are included in the D.07-12-052 adopted load forecasts on which the LTPPs are based.

10. Planning for the needs of IOU customers that are eligible to, and do, choose DA service from an ESP and customers that decide to use a CCA and imposing NBCs, if and when these customers choose alternative procurement services, is reasonable.

11. The loads associated with MDL (with the exception of large municipalizations) and CGDL customers are not included in the CEC load forecasts that were adopted in D.07-12-052 as the forecasts on which new generation needs are to be based in the LTPPs.

12. The LTPP, which uses load forecasts to determine resource needs in the forecast year, does not include any resources to serve forecasted MDL and CGDL in the forecast year and beyond, which result in a fair share of zero, once these customers depart.

13. All other things being equal, exclusion of forecasted departing load from the LTPP load forecasts and exclusion of MDL (with the exception of large municipalizations) and CGDL customers from cost responsibility for new generation resources after the customers depart leaves existing bundled customers with the same cost responsibility as was anticipated when the LTPP load forecasts were made.

14. While the BNI process may be a viable approach for determining when IOU procurement on behalf of certain customers ends, it is not relevant in addressing the NBC applicability issue of whether these departing customers should be assessed any NBC at all under a fair share analysis.

15. Due to the manner in which we have resolved the applicability issue, a BNI process for determining when IOU procurement on behalf of ongoing MDL and CGDL customers ends is unnecessary.

16. It is reasonable for the IOUs to impose D.04-12-048 and D.06-07-029 NBCs on departing load associated with large municipalizations that are not represented in the historical trends used to develop the load forecasts.

17. There is no testimony or other evidence to refute PG&E's claim that D.04-12-048 and D.06-07-029 NBCs should apply to new WAPA departing load and split wheeling departing load.

18. It is reasonable for the IOUs to impose D.04-12-048 and D.06-07-029 NBCs on new WAPA departing load and split wheeling departing load.

19. Bundled customers who are eligible to return to DA service have not specifically been excluded from having to pay the D.04-12-048 NBC.

20. Up until the time that bundled customers who are eligible to return to DA service give proper notice that they will return to DA service, they are no different from the other bundled customers on whose behalf the IOUs are making procurement related decisions.

21. The D.07-09-040 requirement that the utilities make standard offer contracts available to existing QFs with expiring PPAs or to new QFs impacts utility procurement and creates uncertainty in resource planning, and, to the extent the prices in the new QF standard offer contracts are above-market prices, bundled customers may incur additional stranded costs.

22. The general framework of having a customer who chooses an alternative energy supply pay a surcharge that is calculated to cover the uneconomic portion of the resource costs associated with that customer's departure will leave the bundled customer indifferent to the departure and is reasonable for implementing the D.04-12-048 NBC.

23. At this point, the only difference between the separate charge and the total portfolio approaches is how negative charges are handled in the calculations.

24. The total portfolio approach is consistent with prior Commission decision regarding the carryover of negative charges. The separate charge approach is not.

25. The use of the total portfolio approach is necessary to implement provisions of this decision regarding the use of pre-restructuring resources in determining cost responsibility once recovery of the DWR power charge ends.

26. Bundled customer indifference will only be maintained if all resources are included in the portfolio used to calculate the related charges, whether it is the CTC, DWR and D.04-12-048 charges or just the CTC and D.04-12-048 charges.

27. The use of the total portfolio and the inclusion of the pre-restructuring resources in that portfolio is the appropriate approach to use for the duration of D.04-12-048 cost recovery.

28. With the inclusion of D.04-12-048 cost recovery as part of the total portfolio, the reasons cited in D.07-05-005 as to why negative indifference charge carryover is appropriate apply even after expiration of the DWR contract term.

29. The argument that a limitation on the use of pre-restructuring resources fairly offsets any perceived effects of the D.04-12-048 10-year limitation on cost recovery for non-RPS resources is not persuasive.

30. If the IOUs believe a cost recovery period extension is appropriate and necessary for specific resources, they can make such requests under the provisions of D.04-12-048.

31. The Commission has consistently declined PG&E's advice letter requests to recover the above market costs of RPS contracts through a NBC, consistent with its interpretation of D.04-12-048, indicating that it would not address such above market cost recovery in the resolutions but that R.06-12-013 was the appropriate procedural forum for addressing those issues.

32. With respect to the implementation of the stranded cost provisions of D.04-12-048, the NBCs, which include any above market costs related to RPS contracts, will not apply to departing load that is excluded from the load forecasts used to develop the IOUs' LTPPs. The excluded departing load includes MDL, with the exception of large municipalizations, and CGDL. DA and CCA load are fully subject to the D.04-12-048 NBC.

33. When calculating the CRS, the RPS contracts are blended in with other generation resources under the total portfolio analysis.

34. Future developments in the State's renewable and/or greenhouse gas policies may both necessitate and facilitate a review of the manner in which renewables attributes are treated with respect to departing load and the new generation NBC to best maintain ratepayer indifference and the State's various policy objectives.

35. It is necessary to have some simplifying methodology so that the IOU does not have to figure out and administer the actual vintage (date of departure) for every customer.

36. Since customers who are eligible to return to DA have not been excluded from having to pay the NBC associated with D.04-12-048, it is necessary to determine a vintaging methodology for customers choosing DA, as part of this decision.

37. Under PG&E's vintaging (date of departure) proposal, where customers leaving in a particular year would be responsible for stranded costs associated with new generation resource commitments made through the end of that year, most customers will have assigned departure dates that are later than actual.

38. Under SCE's vintaging (date of departure) proposal, where customers leaving in the first half of any particular year would be responsible for stranded costs associated with new generation resource commitments made through the end of the previous year and where customers leaving in the second half of any particular year would be responsible for stranded costs associated with new generation resource commitments made through the end of that particular year, there will be customers with assigned departure dates that are both earlier and later than actual.

39. Over the long term, potential benefits and adverse effects to bundled customers would tend to balance out under SCE's vintaging proposal, but would not under PG&E's proposal.

40. The SCE vintaging proposal, when compared to the PG&E proposal, is fairer for customers that are leaving and more appropriately reflects bundled customer indifference.

41. AReM's alternative proposal to use commitments as of June 30 of any particular year for vintaging DA customers leaving bundled service in that year is similar to SCE's proposal in that, over time, the effect of customers having assigned departure dates earlier than the actual dates would be balanced by the effect of customers having assigned departure dates later than the earlier the actual dates.

42. AReM's alternative vintaging proposal would require mid-year revenue requirement determinations for costs normally determined on a full calendar year basis.

43. For consistency, SCE's vintaging proposal is preferable to that of AReM.

44. The six-month vintaging proposal by EPUC is problematical because most assigned departure dates will be later than the actual departure dates, and the proposal is administratively burdensome.

45. In determining the CRS which includes the D.04-12-048 NBC, (a) the use of the market benchmark adopted in D.06-07-030, as modified by D.07-01-030, to determine above-market costs and (b) the use of a forecast of costs, done through the ERRA, without an after-the-fact true-up, are reasonable.

46. It is not equitable for customers who will only be paying for 10 years of a project's depreciation to be entitled to the entire reduced revenue requirement

effect that results from the accumulated depreciation that will have been paid by other customers for 30 years or more.

47. The need for workshops related to the determination of capacity adders and line loss adjustments has not been demonstrated.

48. The costs for future new generation resources, the future market benchmark prices and the future amounts of load shifting caused by DA, CCA, MDL and CGDL would be principal elements in a detailed cost-effectiveness analysis of NBCs, and are generally unknown at this time.

49. In light of potentially significant amounts of new generation NBC revenues, it is reasonable to incur costs to implement the NBCs.

50. The incremental costs of billing and collecting the new generation NBCs are likely to be negligible.

51. Once the charges are in place, it is reasonable for the IOUs to collect the NBCs without continually having to demonstrate cost-effectiveness for particular charges for particular customers.

52. The Merced ID/Modesto ID assertion regarding the possible high level of stranded cost recovery is very general and not supported by any specific basis or reasoning.

53. Prior to the costs of any of the new generation resources being included in the revenue requirement and being eligible for stranded cost recovery, the Commission will have already examined both the need and costs of the projects.

54. It is not necessary to establish an annual procedure to determine whether it is appropriate to establish and implement a stranded cost recovery cap.

55. PPA costs to the IOU and the associated cost recovery from customers will begin with the commencement of operation of the project.

56. Regarding the D.06-07-029 NBC, customers who choose DA or CCA will be assessed a NBC for the net cost of capacity, and the LSE to which they migrate will receive the related RA credits.

57. Since the IOUs are not procuring system reliability resources on behalf of the POUs, and CGDL customers are not LSEs, there is no direct use of RA credits for these departing customers, to the extent such customers are subject to the CAM.

58. Where RA credits are not directly assigned to an LSE, bundled customer indifference can be achieved by placing a value on the RA credit and having the IOU net that amount out of the NBC and letting the IOU maintain that RA credit for its use.

59. EPUC has raised specific CAM concerns that relate only to CGDL customers but has indicated that these concerns need not be addressed, if CGDL customers are excluded from the CAM.

60. The D.06-07-029 NBC, which is based on a cost that is net of the energy value and which has associated RA credits, is distinct from the elements of the DA CRS, which have both energy and capacity costs and no RA credits.

61. The principles for the energy auction process and products as adopted by D.07-09-044 state that net costs shall be calculated and determined separately for each Energy Auction PPA, and net costs shall not be netted against or in any way impacted by the costs of other resources in the utility's resource portfolio.

62. The 2.7 cent/kWh DA CRS caps will have expired for all three IOUs by the end of 2008.

63. The ESPs will be receiving RA credits and they should pay for such credits as they are received and used, not on a deferred basis, which might result with the reinstatement of the DA CRS cap.

64. AReM only addresses IOU procurement flexibility in the context of increased DA load.

65. AReM does not address the manner in which the IOUs would adjust their procurement when faced with all DA, CCA, and departing load possibilities or whether any of the adjustments might result in additional costs that would be borne by bundled customers only.

Conclusions of Law

1. MDL and CGDL customers should not pay any NBCs related to new generation resources that were not procured on their behalf.

2. Forecasting the effects of CGDL and MDL has been done in the past, is reasonable and should continue in developing the load forecasts for LTPP purposes.

3. Imposition of the D.04-12-048 and D.06-07-029 NBCs is not necessary or appropriate for MDL or CGDL customers, since MDL and CGDL is factored into (i.e., the associated loads are excluded from) the CEC load forecasts for the IOUs adopted in D.07-12-052 for the 2006 and future LTPPs, and therefore the fair share of these customers should be zero upon departure.

4. For departing loads of large municipalizations that are not reflected in the historical trends used in developing the adopted LTPP load forecasts, the IOUs should file an application requesting a Commission determination of the fair share of these customers for paying the D.04-12-048 and D.06-07-029 NBCs.

5. The D.04-12-048 and D.06-07-029 NBCs should be imposed on new WAPA departing load and split wheeling departing load, consistent with D.06-05-018 and D.03-09-052.

6. Since the IOUs are procuring and making procurement commitments on behalf of bundled service customers who are eligible to return to DA service up

until the dates associated with these customers' notices to return to DA service, these customers should, as is the case with all other customers, be responsible for those procurement commitments made on their behalf and should be subjected to the D.04-12-048 NBC.

7. The IOUs should be able to recover above-market costs of new QF standard offer contracts through the D.04-12-048 NBC.

8. The total portfolio approach should be used for calculating the D.04-12-048 NBC.

9. To the extent that they continue to exist, pre-restructuring resources should continue to be included in the total portfolio for the duration of the D.04-12-048 NBC cost recovery.

10. The current provisions related to negative indifference charge carryover for use in subsequent years should be continued once DWR power charge recovery ends.

11. The effects of the 10-year limitation on cost recovery of new non-RPS generation resources on bundled customer indifference should be considered, on a case-by-case basis, if and when the IOUs request cost recovery extensions, pursuant to the provisions of D.04-12-048.

12. Given the potential long-term nature of the charge, allowances should be made for the possibility that certain future circumstances may result in a need to modify the D.04-12-048 NBC related processes adopted in this decision.

13. AReM's request to defer the development of a vintaging system for DA customers to R.07-05-025 should be denied.

14. SCE's vintaging (date of departure) proposal should be adopted.

15. Regarding vintaging, "the time a commitment is made" is when the IOU executes a contract or begins the construction of a new generation resource, not

when deliveries begin under the contract or the generation resource becomes operational.

16. Levelized fixed cost recovery should not be used for determining the D.04-12-048 NBC.

17. Workshops related to the determination of capacity adders and line loss adjustments should not be required.

18. The cost-effectiveness of NBCs should not be pursued any further in this proceeding.

19. The D.04-12-048 NBC 10-year cost recovery period for PPAs should begin with the commencement of operation of the project.

20. To the extent that large municipalization customers are subject to the CAM, the departing customers should be responsible for any uneconomic PPA costs which are represented by the total annual PPA cost, less energy auction revenues, less the value of the RA credit, with the IOU retaining the RA credit for its own use.

21. Since, by this decision, CGDL customers have been excluded from the CAM, it is not necessary to address EPUC's CAM concerns that relate only to CGDL customers.

22. The DA CRS and the D.06-07-029 NBC should be calculated and billed as separate items.

23. The need and equity of AReM's proposal to include the D.06-07-029 NBC under a 2.7 cent/kWh DA CRS cap has not been demonstrated, and the proposal should not be adopted.

24. There is insufficient justification for modifying the length of the CAM as adopted in D.06-07-029, and AReM's recommendation to do so should not be adopted.

25. This decision should be made effective immediately.

O R D E R

IT IS ORDERED that:

1. Decision (D.) 04-12-048 and D.06-07-029 non-bypassable charges (NBCs) shall be imposed on direct access (DA) and community choice aggregation customers, as well as new Western Area Power Administration (WAPA) departing load and split wheeling departing load customers.

2. Because customer generation departing load (CGDL) and municipal departing load (MDL) are excluded, as classes, from the adopted load forecasts on which the investor-owned utilities (IOUs) long term procurement plans (LTPPs) are based, CGDL and MDL customers are excluded from having to pay the D.04-12-048 and D.06-07-029 NBCs, including any above market costs related to RPS contracts, with the exception of those customers described in Ordering Paragraph 3.

3. Consistent with the provisions in this decision, an IOU may file an application requesting implementation of the D.04-12-048 and D.06-07-029 NBCs on departing load associated with a large municipalization. In the application, the IOU should demonstrate how the loads of these customers were included in an adopted load forecast, establishing that the IOU reasonably incurred costs on behalf of such customers. The Commission will determine the fair share of these customers for paying the D.04-12-048 and D.06-07-029 costs based on a departure date established through a binding notice of intent or alternative process.

4. Bundled service customers who are eligible to return to direct access shall not be excluded from having to pay the NBC associated with D.04-12-048.

5. The IOUs are allowed to recover the above-market costs of new qualifying facilities standard offer contracts through the D.04-12-048 NBC.

6. As described in the body of this decision, the D.04-12-048 NBC shall be implemented as a component of the cost responsibility surcharge (CRS), calculated on a total portfolio basis with the netting of individually calculate annual charges and the carrying over of negative total charges for use in offsetting positive charges in subsequent years.

7. Pre-restructuring resources shall continue to be included in the portfolio of resources used in determining D.04-12-048 charges, once recovery of DWR power costs ends.

8. If, due to future changing circumstances, the processes adopted by this decision for determining the D.04-12-48 NBC become unworkable, unbalanced, or unfair, parties may propose and request modifications to the form of the NBC or how the NBC should be determined or calculated.

9. The Alliance for Retail Energy Market's request to defer the development of a vintaging system for DA customers to Rulemaking (R.) 07-05-025 is denied.

10. A vintaging (date of departure) methodology, where customers leaving in the first half of any particular year would be responsible for stranded costs associated with new generation resource commitments made through the end of the previous year, and where customers leaving in the second half of any particular year would be responsible for stranded costs associated with new generation resource commitments made through the end of that particular year, is adopted.

11. Levelized fixed cost recovery shall not be used in determining the D.04-12-048 NBC.

12. The D.04-12-048 NBC 10-year cost recovery period for power purchase agreements (PPAs) shall begin with the commencement of operation of the project.

13. To the extent that large municipalization, new WAPA departing load or split wheeling departing load customers are subject to the cost allocation mechanism (CAM), the departing customers should be responsible for any uneconomic PPA costs which are represented by the total annual PPA cost, less energy auction revenues, less the value of the resource adequacy (RA) credit, with the IOU retaining the RA credit for its own use.

14. The DA CRS and the D.06-07-029 NBC shall be calculated and billed as separate items.

15. The D.06-07-029 NBC shall not be included under a 2.7 cent per kilowatt hour DA CRS cap.

16. The maximum term length of the CAM shall remain at 10 years, as adopted in D.06-07-029.

17. The Northern California Power Association's Motion for Party Status, filed August 14, 2008, is granted.

18. R.06-02-013 is closed.

This order is effective today.

Dated _____, at San Francisco, California.

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APPENDIX A

********** SERVICE LIST **********

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R0602013 LIST

(END OF APPENDX A)

APPENDIX B
List of Acronyms and Abbreviations

A. - Application

AB – Assembly Bill

ACR – Assigned Commissioner's Ruling

ALJ – Administrative Law Judge

AReM – Alliance for Retail Energy Markets

BNI – Binding Notice of Intent

CAM – Cost Allocation Mechanism

CAC – Cogeneration Association of California

CCA – Community Choice Aggregation/Aggregator

CCDC – California Clean DG Coalition

CCSF – City and County of San Francisco

CEC – California Energy Commission

CGDL – Customer Generation Departing Load

CMUA – California Municipal Utilities Association

CRS – Cost Responsibility Surcharge

CTC – Competition Transition Charge

D. – Decision

DA – Direct Access

DG – Distributed Generation

DL – Departing Load

DRA – Division of Ratepayer Advocates

DWR – Department of Water Resources

ECRA – Energy Cost Recovery Amount

EPUC – Energy Producers and Users Coalition

ERRA – Energy Resources Recovery Account

ESP – Electric Service Provider

HPC – Historical Procurement Charge

IEPR – Integrated Energy Policy Report

IOU – Investor Owned Utility

LSE – Load Serving Entity

LTPP – Long-Term Procurement Plan

Merced ID – Merced Irrigation District

Modesto ID – Modesto Irrigation District

MDL – Municipal Departing Load

NBC – Non-bypassable Charge

PCIA – Power Charge Indifference Amount

PD – Proposed Decision

PG&E – Pacific Gas and Electric Company

PPA – Power Purchase Agreement

POU – Publicly Owned Utility

QF – Qualifying Facility

R. – Rulemaking

RA – Resource Adequacy

RPS – Renewable Portfolio Standard

SCE – Southern California Edison Company

SDG&E – San Diego Gas & Electric Company

SSJID – South San Joaquin Irrigation District

TURN – The Utility Reform Network

URG – Utility retained Generation

WAPA – Western Area Power Administration

WPTF – Western Power Trading Forum

(END OF APPENDIX B)

APPENDIX C

List of Terms

Following are terms defined in the context of this decision:

Binding Notice of Intent (BNI) -- A commitment to a target date, at which point a CCA is responsible for its own energy procurement and resource adequacy. If the CCA does so, its customers will not be responsible for stranded costs of any utility commitments entered into after the agreed upon date. However, if the CCA does not meet the target date, it will be liable for any incremental costs that the utility incurs in excess of its average portfolio cost to serve the load that the CCA is not able to serve.

Bundled Customer Indifference – A principle, whereby bundled customers should be no worse off, nor should they be any better off as a result of customers departing the system or choosing alternative energy suppliers.

Community Choice Aggregator (CCA) – Governmental entities formed by cities and/or counties to serve the energy requirements of their local residents and businesses. The IOU continues to provide transmission and distribution service.

Cost Adjustment Mechanism (CAM) – Mechanism authorized by D.06-07-029, by which customers are allocated both the net costs of capacity (total PPA costs less energy auction revenues) and the associated capacity rights.

Cost Responsibility Surcharge (CRS) – A surcharge developed to recover certain costs from departing customers. Existing surcharges cover DWR bond and power charges and ongoing competition transition charges. PG&E also collects for the ECRA which recovers bankruptcy-related costs.

Customer Generation Departing Load (CGDL) – Departing load associated with cogeneration, renewable technologies, or any other type of generation that (a) is dedicated wholly or in part to serve a specific customer's load; and (b) relies on non-utility or dedicated utility distribution wires rather than the utility grid, to serve the customer, the customer's affiliates and/or tenant's, and/or not more than two other persons or corporations.

Direct Access (DA) - The ability of a retail customer to purchase commodity electricity directly from the wholesale market rather than through a local distribution utility. DA customers purchase electricity from an independent electric service provider and receive transmission and distribution service from the IOU.

Departing load (DL) – DL generally refers to retail customers who were formerly IOU customers but now receive energy, transmission and distribution services from publicly owned utilities, self-generation or other means.

Fair Share – A customer's cost responsibility for activities performed by the utility on behalf of that customer.

Indifference – Indifference is when the cost of the total portfolio of resources is the same as a market benchmark. In that case, bundled customers are indifferent to departing load. A positive indifference amount indicates the total portfolio costs exceed the market benchmark which indicates that the costs are uneconomic or stranded. A negative indifference amount indicates the total portfolio costs are below the market benchmark.

Large Municipalization - Large municipalization refers to any portion of an IOU's service territory that has been taken control of or annexed by a POU where the amount of load departing the IOUs' service territories due to the municipalization is of such a large magnitude that it cannot reasonably be assumed to have been reflected as part of the historical MDL trends used in developing the adopted LTPP load forecasts.

Municipal Departing Load (MDL) – MDL refers to DL served by a POU as that term is defined in Public Utilities Code Section 9604(d), including municipalities or irrigation districts. For purposes of this decision, MDL also includes new MDL, which is load that has never been served by an IOU but is located in an area that had previously been in the IOU's service territory (as that territory existed on February 1, 2001) and was annexed or otherwise expanded into by a POU.

New Generation – New generation includes generation from both fossil fueled and renewable resources contracted for or constructed by the investor owned utilities subsequent to January 1, 2003.

New WAPA Departing Load – Additional customer load of certain so-called 'new allottee" customers who, for example, were served by PG&E under its retail tariffs prior to expiration of Contract 2948-A with WAPA but are now served by WAPA.

Non-bypassable Charge (NBC) -- A charge that cannot be avoided by departing the system or obtaining alternative services. In this decision, the new generation NBCs are those imposed on all customers, based on their fair share of new generation costs, even if they no longer require utility energy procurement services.

Power Charge Indifference Amount (PCIA) – The DWR power portion of the CRS.

Pre-restructuring Resources - For purposes of this decision, pre-restructuring resources refers to those current IOU resources that existed prior to March 31, 1998 and are not subject to ongoing CTC treatment. These resources consist principally of the IOUs' retained generation (i.e., hydro, coal and nuclear plants). Power from these resources tends to be cheaper when compared to the costs related to ongoing CTC, the DWR contracts and new generation.

Qualifying Facility (QF) – An independent power producer that meets certain regulatory requirements for supplying power to a utility under contract. QFs use cogeneration or renewable resources to generate electricity.

Split Wheeling Departing Load – That portion of the load of certain so-called "split-wheeling" customers which, for example, was served by PG&E under its retail tariffs prior to the expiration of PG&E's Contract 2948-A with WAPA but is now served by WAPA.

Stranded Costs – Costs related to utility investments in generation plants or long-term power contracts that are not economical in a competitive market.

Vintaging – The process of assigning a departure date to departing customers in order to determine those customers' generation resource obligations.

(END OF APPENDIX C)