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LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW

P. O. BOX 1448
TUBAC, ARIZONA 85646

(520) 398-0411
FAX: (520) 398-0412
EMAIL: TUBACLAWYER@AOL.COM

OF COUNSEL TO
MUNGER CHADWICK, P.L.C.

ADMITTED TO PRACTICE IN:
ARIZONA, COLORADO, MONTANA,
NEVADA, TEXAS, WYOMING,
DISTRICT OF COLUMBIA

April 2, 2010

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Arizona Corporation Commission
DOCKETED
APR - 2 2010
DOCKETED BY

Re: Generic Proceeding Concerning
Electric Restructuring Issues
Docket No. E-00000A-02-0051
E-00000A-01-0630

To Whom It May Concern:

Enclosed for filing in the above-referenced docket are the original and thirteen (13) copies of Supplemental Comments on behalf of Sempra Energy Solutions LLC, Direct Energy, LLC, Constellation NewEnergy, Inc. and Shell Energy North America (US), L.P.

Please let me know if you have any questions. Thank you for your assistance.

Sincerely,

Angela R. Trujillo
Secretary
Lawrence V. Robertson, Jr.

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING ELECTRIC RESTRUCTURING ISSUES	Docket No. E-00000A-02-0051 E-00000A-01-0630

SUPPLEMENTAL COMMENTS OF SEMPRA ENERGY SOLUTIONS LLC, DIRECT ENERGY LLC, CONSTELLATION NEWENERGY, INC. AND SHELL ENERGY NORTH AMERICA (US), L.P.

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400 W CONGRESS STE 218 TUCSON AZ 8570*

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

I.

INTRODUCTION

On March 12, 2010, a representative of the Staff of the Arizona Corporation Commission ("Commission") electronically transmitted the following "request for comments from interested parties" in connection with the above-captioned and above-docketed proceeding ("instant proceeding"):

> "Staff of the Arizona Corporation Commission held a workshop on retail electric competition on November 14, 2008. At the workshop, Staff asked the participants to file written comments on several topics. Comments had been due by January 30, 2009. Staff is interested in receiving comments from interested parties who would like to refresh their responses or who had not previously responded on the following topics:
>
> 1) potential risks and benefits of retail electric competition,
> 2) whether or not retail electric competition is in the public interest,
> 3) provider of last resort,
> 4) whether the Commission's current electric competition rules are adequate,
> 5) costs of competition, and
> 6) other issues related to retail electric competition."

Sempra Energy Solutions LLC, Direct Energy LLC, Constellation NewEnergy, Inc. and Shell Energy North America (US), L.P. (collectively "Competitive Electric Service Providers") have previously participated as "interested parties" in the above-referenced November 14, 2008 workshop on retail electric competition; and, acting in that same status, on January 30, 2009, jointly filed with the Commission's Docket Control detailed Comments in the instant proceeding. In response to the aforesaid electronic request, the Competitive Electric Service Providers now submit the following Supplemental Comments.

II.

INFORMATIONAL BACKGROUND

The six (6) topics upon which the Commission's Staff has requested comment were either directly or essentially addressed in the January 30, 2009 Comments previously filed by the Competitive Electric Service Providers. Accordingly, and in the interest of brevity, those Comments (including Appendices "A" through "E" thereto) are incorporated herein by this reference as informational background to the discussion set forth below in these Supplemental Comments.

III.

COMMENT UPON TOPICS 1 THROUGH 5 IDENTIFIED BY COMMISSION STAFF

A. Potential Risks and Benefits of Retail Electric Competition (Topic 1)

1. "RISKS"

In Section III of their January 30, 2009 Comments, the Competitive Electric Service Providers specifically addressed and rebutted "risks" associated with retail electric competition, which certain participants in the November 14, 2008 workshop endeavored to suggest exist. As therein noted, to the extent any such asserted risks exist, the same would either be offset by the tangible benefits to be achieved through competition or controlled through measured regulation, including rules, and tariffs provisions which have been approved by the Commission.

> "In fact, Arizona's current approach to retail electric competition has been designed to protect both the utility and the end-use customers from risk. The Commission has established rules for customer switching, credit support, utility notification, REST, and scheduling power through the AZISA. The Commission has also addressed utility cost recovery for stranded costs and business systems needed to implement retail competition. In summary, Arizona's risks are low, but its potential benefits are high. Some argue that the Commission should "go slow" in re[in]stating retail electric competition. We counter that this process has been methodical and that Arizona is now in great danger of lagging significantly behind other states in its competitive framework, disadvantaging businesses that need to compete in today's global economy. We urge the Commission to take action now." [January 30, 2009 Comments at page 20, lines 17-27]

With one (1) exception, nothing has occurred during the past fifteen (15) months to alter the accuracy of any of the above-stated conclusions. That one (1) exception pertains to the risk of Arizona's economy

"... lagging significantly behind other states in its competitive framework. . ."

because of the current absence of retail electric competition within Arizona. With the continuation and expansion of retail electric competition in a number of other states, and with the impending re-opening of retail electric competition to new customers in the neighboring State of

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

California,[1] the "risk" of Arizona lagging further behind may well have increased to the substantial detriment of Arizona's future economic prospects and labor market, absent prompt resumption of retail electric competition.

2. "BENEFITS"

In Section II(A) of their January 30, 2009 Comments, the Competitive Electric Service Providers discussed the "benefits" associated with retail electric competition from the perspective of (i) the retail electric consumer, (ii) the electric utility and (iii) the Commission.

From an overview perspective, the benefits resulting from retail electric competition include (i) creating downward pressure on energy prices, (ii) improvement in the competitiveness of energy-intense businesses, (iii) creating demand for and facilitating use of renewable energy resources and products, and (iv) providing innovative new products for and services to the market place. In addition, retail electric competition offers the electricity consumer the freedom of choice as to both product and supplier. From the perspective of the electric utility, retail competition offers the additional benefits of a reduction in the need for capital to construct or procure new generation resources, and the associated credit requirements, as well as the prospect of an additional means by which the regulatory obligations under the Renewable Energy Standards and Tariff ("REST") can be satisfied. Consonant with this latter benefit is the Commission's support for and recognition of the importance of the Arizona Independent Scheduling Administrator ("AISA").[2] Finally, from the perspective of the Commission, each of the aforementioned benefits positively impacts the duality of consumer and utility interests it must consider incident to the discharge of its responsibilities.

However, none of these benefits is self-executing in nature. Rather, they can be realized only through a decision by the Commission to reinstate retail electric competition in Arizona. In

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[1] See Section IV(B)(1) below of these Supplemental Comments for a discussion of recent legislative and regulatory developments in California relating to the resumption of retail electric competition.

[2] "We find that Phelps Dodge had no impact on the continuing economic viability of the AISA, and that it does not reduce the continued public benefit associated with maintaining Commission support of the AISA at its current level of operations. The AISA currently provides the important public benefit of keeping the possibility of retail access available in Arizona to consumers at a minimal cost, by providing potential competitors with the necessary assurance that they will have fair and equitable access to transmission until an RTO is formed and approved by FERC to take over that function." [Decision No. 68485, page 15, lines 5-11] [emphasis added]

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

that regard, as the Competitive Electric Service Providers observed in their January 30, 2009 Comments:

> "Moreover, retail competition has been shown to provide substantial benefits wherever it has been introduced, including providing downward pressure on prices, improving competitiveness of businesses, creating demand for renewable products, and providing innovative new products and services to the electric market for all customers, large and small. Further, retail electric competition has achieved this demonstrated success using many different models with each state designing their own programs based on their specific policy goals. Moreover, states with successful retail markets have processes in place that allow for review and modification of the programs and protocols to ensure that the programs are refined over time as states adopt new policy goals or seek to enhance the success of their programs.
>
> Arizona's current model is similarly workable. Reinstating competitive retail electric service would require neither a substantive "re-vamping" of the rules nor a time-consuming rulemaking proceeding to examine new utility services. Further, Arizona has designed its rules to minimize risk. The Commission has also established rules for customer switching, utility notification, and the Renewable Energy Standards and Tariff ("REST") and has addressed utility cost recovery for stranded costs and business systems needed to implement retail competition. In short, Arizona is well positioned to reinstate retail electric competition." [January 30, 2009 Comments at page 1, line 18-page 2, line 10] [emphasis added]

Such reinstatement can and should begin with the Commission's (i) convening an evidentiary hearing on the currently pending Application of Sempra Energy Solutions LLC ("SES") in Docket No. E-03964A-06-0168 for an Electric Service Provider ("ESP") certificate of convenience and necessity ("CC&N"), and (ii) thereafter issuing a decision granting SES an ESP CC&N with such conditions as the Commission deems appropriate. This step will pave the way for additional retail competitors to secure their CC&Ns, so that competitive retail choice can finally begin for customers for Arizona consumers.

B. Whether Or Not Retail Competition Is In The Public Interest (Topic 2)

Section II of the Competitive Electric Service Providers January 30, 2009 Comments (and Appendices "A" through "E" thereto) address this topic at length. In that regard, and as it should be, consideration of this issue necessarily encompasses an analysis of the potential "benefits" and "risks" associated with retail electric competition.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

As noted in the discussion set forth above in Section II(A)(1) and (2) above of these Supplemental Comments (i) the potential "benefits" of retail electric competition clearly outweigh and offset any potential "risks"; and, (ii) each of the potential "risks" can be avoided or managed through measured regulation in the form of ESP CC&N conditions and/or regulations which are within the Commission's authority, as is done in every other jurisdiction with retail electric competition in the U. S.

In summary, retail electric competition has been determined to be in the "public interest" by both legislatures and utility regulatory commissions in a number of states. Those states include Arizona, as evidenced by (i) the Arizona Legislature's enactment of A.R.S. § 40-202(B), and (ii) the Commission's adoption of its current retail electric competition rules, as set forth at A.A.C. R14-2-1601 et seq. To the knowledge of the Competitive Electric Service Providers, there have been no legal or factual developments in the intervening years which would suggest a need to revisit or rescind those previous Arizona legislative and regulatory policy determinations that retail electric competition is in the "public interest."

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

C. Provider of Last Resort (Topic 3)

The topic of "provider of last resort" ("POLR") is addressed at length in the two (2) studies attached as Appendices "B" and "C" to the Competitive Electric Service Providers January 30, 2009 Comments. Appendix "B" pertains to experience with commercial and industrial electric consumers, and Appendix "C" relates to experience with residential consumers. As noted in the aforesaid January 30, 2009 Comments:

> "The 2008 study results, provided in Appendices B and C, show a variety [of] retail choice models including those that have POLR or default service and those that do not, programs that have POLR or default service supplied by the utility and those that supply it through the competitive market, models that allow all customers to shop for electricity and those that restrict eligibility, designs that operate within the confines of ISOs and those that have no such organized markets, programs that have required utilities to divest generating assets and those that remain vertically-integrated, and markets with many variations in the type of renewable portfolio standards required for retail suppliers. In short, there are significant variations among competitive retail models. The bottom line, however, is that the states have determined the model that they wish to implement.
>
> Closer to home, Washington, Oregon and California all have some form of retail competition in which the utility distribution company ("UDC") provides

> default service based on cost-of-service rates, as Sempra Energy Solutions contemplates in its Arizona CC&N application. The UDCs in these three western states procure power for their bundled load under the direct supervision of their regulators, and all customer classes, including large commercial customers, can elect utility service or competitive retail providers, subject to each state's switching protocols." [January 30, 2009 Comments at page 10, line 12-page 11, line 4] [emphasis added]

Thus, the concept of a POLR is neither an obstacle nor an impediment to the reinstatement of retail electric competition in Arizona.

D. Adequacy of the Commission's Current Electric Competition Rules (Topic 4)

The Merriam Webster Dictionary defines "adequate" and "adequacy" as

"... equal to or sufficient for a specific requirement..."[3]

The question implicitly posed by this topical selection of the Commission's Utilities Division staff is actually two-fold in nature. First, can the Commission resume retail electric competition under the Commission's current retail electric competition rules? Second, can the market conditions necessary for beneficial retail electric competition exist under those same rules?

1. FIRST QUESTION

In Section II(A)(4) and Appendix "A" of their January 30, 2009 Comments, the Competitive Electric Service Providers discussed the first question at length.[4] The principal points made during that discussion were the following, as set forth in Appendix "A" to the January 30, 2009 Comments:

> "A.R.S. 6 40-202(B) declares that "it is the public policy of this state that a competitive market shall exist in the sale of electric generation service," and it "confirms" a wide range of powers of the Commission to accomplish the "transition to competition for electric generation service." Such powers include the authority of the Commission to "establish reasonable requirements for certificating and regulating electricity suppliers that are public service corporations." [A.R.S. 0 40-202(B)(2)]" [page 1, lines 7-13]

* * *

[3] See 1997 edition.

[4] The question of whether or not the current rules were legally "adequate" to provide for retail electric competition had been occasioned by a 2004 decision in Phelps Dodge Corporation v. Arizona Electric Power Cooperative, Inc., 207 Ariz. 95, 83 P.3d 573 (Ct. App. 2004) in which the Arizona Court of Appeals invalidated certain of the retail electric competition rules previously adopted by the Commission for various reasons. A resulting impact of the Phelps Dodge decision was the invalidation of previous Commission decisions granting ESP CC&Ns to approximately a dozen entities, including SES' predecessor-in-interest.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

"A.R.S. § 40-281(A) provides 'a public service corporation shall not begin . . . service . . . without having first obtained from the Commission a certificate of public convenience and necessity.' It is further important to note that neither A.R.S. § 40-202(B) or A.R.S. § 40-281(A) require the existence of rules or regulations governing the transition to competition as a condition precedent to the legal authority of the Commission to grant an ESP CC&N. Rather, whether and when to grant an ESP CC&N is entirely within the discretion of the Commission, subject to its compliance with applicable Arizona law." [page 1, lines 9-13]

* * *

"The Phelps Dodge decision does not stand for the proposition that the Commission cannot grant ESP CC&Ns until a complete set of electric competition rules has been legally promulgated. That issue was not before the Arizona Court of Appeals; and a conclusion to that effect would be inconsistent with applicable Arizona law." [page 1a, lines 9-13]

* * *

". . . interim developments in the electric utility industry in Arizona pertaining to the Arizona Independent Scheduling Administrator ("AISA"), as well as a related Commission decision, suggest that the Phelps Dodge decision does not preclude AISA from continuing to perform an important role in relation to retail electric competition. In this regard, in Decision No. 68485, the Commission stated

> 'We find that Phelps Dodge had no impact on the continuing economic viability of the AISA, and that it does not reduce the continued public benefit associated with maintaining Commission support of the AISA at its current level of operations. The AISA currently provides the important public benefit of keeping the possibility of retail access available in Arizona to consumers at a minimal cost, by providing potential competitors with the necessary assurance that they will have fair and equitable access to transmission until an RTO is formed and approved by FERC to take over that function.' [Decision No. 68485, page 15, lines 5-11]" [page 2, lines 11-23]

* * *

"With reference to R14-2- 16 15(A) and (C) [Separation of Monopoly and Competitive Services], the Phelps Dodge decision found subsections (A) and (C) were beyond the Commission's plenary ratemaking powers, and without separate statutory authorization, and were thus invalid. However, the court also found that the intended separation of monopoly and competitive services could still be achieved through Affected Utilities' compliance with R14-2-1615(B), which was not challenged. More specifically, the court stated:

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

> 'If the Affected Utilities choose to retain competitive assets for a period beyond the prescribed date, or indefinitely, the competitive market is seemingly unaffected, as long as the Affected Utilities abide by R14-2-1615(B), which prohibits them from competing." [Phelps Dodge at p. 181]

Hence, there is no legal or functional need to replace R14-2-1615 (A) and (C) with new regulations." [page 2, line 24-page 3, line 8]

* * *

"The electric competition rules, which were invalidated by the Phelps Dodge decision because they were not submitted to the Arizona Attorney General for Certification under the Arizona Administrative Procedure Act ("APA"), also are not indispensable to the ability of the Commission to effectively oversee and regulate retail electric competition. . ." [page 3, lines 10-13]

* * *

"The Commission can validate those Electric Competition Rules, invalidated by the Phelps Dodge decision for failure to obtain that Arizona Attorney General Certification required by the_APA, by promptly submitting the same to the Arizona Attorney General and requesting the_requisite certification. In that regard, and with respect to the Commission's legal ability to act_promptly, as the Phelps Dodge decision notes:

> "The APA does not require the Commission to conduct any evidentiary hearing before promulgating rules." [Phelps Dodge at P.191

Hence, the Commission could simply submit the affected Electric Competition Rules to the Arizona Attorney General in their present form and content without the need for further proceedings. Moreover, the Commission can condition the effectiveness of any ESP CC&N it might grant at this juncture upon receipt of the requisite Arizona Attorney General Certification for those Electric Competition Rules, previously invalidated for the lack of such certification." [page 4, lines 13-26]

* * *

"The Phelps Dodge decision does not stand for the proposition that the Commission may not lawfully approve rates and charges for lawfully certificated ESPs for the provision of competitive retail electric service. Rather, Phelps Dodge [simply] held that, in approving rates and charges for the ESPs which had previously been certificated, the Commission failed to satisfy the requirements of Article 15, Section 14 and Article 15, Section 3 of the Arizona Constitution, incident to an exercise of the Commission's plenary ratemaking powers.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

> In addition, the Phelps Dodge decision provides specific guidance to the Commission as to what it must do and what it may consider, incident to the establishment of rates and charges for an ESP for the provision of competitive retail electric service." [page 5, lines 9-19]

In summary, the Commission's authority to grant these CC&Ns derives from a combination of: (a) Article 15 of the Arizona Constitution and (b) Title 40 of the Arizona Revised Statutes ("A.R.S."). Second, the Commission's authority to prescribe or approve rates for retail electric service provided by retail energy suppliers derives from the Commission's authority under Article 15, Section 3 of the Arizona Constitution, which authority is acknowledged and "confirmed" in A.R.S. § 40-202(B). Moreover, the Phelps Dodge decision has not altered the Commission's authority to grant a CC&N to a qualified retail energy supplier applicant, thereby authorizing the applicant to provide competitive retail electric services. The Phelps Dodge decision does nothing to prohibit the Commission from lawfully approving rates and charges for lawfully certificated retail energy supplier for the provision of competitive retail electric service.

If the Commission wishes to consider substantive and procedural modifications to its current competitive retail electric program, these can be evaluated on a parallel track once the CC&Ns are issued and implemented prospectively. Arizona's risks are low, but the potential benefits of moving forward are significant and are of high value. Action is needed now to afford Arizona citizens and customers the products and services they both need and demand to compete in today's global economy.

Thus, the answer to the first question implicitly posed within this topical selection of the Commission's Staff is "*Yes*." There is nothing in the Commission's current retail electric competition rules which per se precludes the Commission from exercising its authority under A.R.S. § 40-202(B) and 40-281(A) to allow the resumption of retail electric competition by means of appropriately conditioned ESP CC&Ns, provided that the Commission properly and fully discharges its constitutional responsibilities pursuant to Article 15, Sections 3 and 14 of the Arizona Constitution.[5]

[5] In connection with the preceding discussion in this Section III(D)(1), attached hereto as Table A-1 is a table that depicts the current legal status of the Electric Competition Rules in the aftermath of the Phelps Dodge decision. In

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

2. SECOND QUESTION

The Competitive Electric Service Providers believe that the question of whether or not economically viable retail electric competition can exist under the Commission's current rules can only be answered to a definitive certainty by allowing the resumption of such competition at this time. It is not a question which can be answered in the abstract, although experience in other states strongly suggests that the answer to the question is a resounding "Yes." Nor can a meaningful answer be obtained by drawing upon Arizona's brief experience of almost a decade ago. Market conditions were substantially different at that time, retail suppliers were less experienced, and customers were yet to understand the benefits of retail choice.

E. Costs of Competition (Topic 5)

During the November 14, 2008 workshop, participants raised two concerns regarding the costs of competition: (1) "cherry picking" of customers; and (2) cost to utilities of systems necessary to implement customer switching.

Those concerned with the notion of "cherry picking" seem to be arguing that all the "high-value" utility customers would depart, leaving the remaining customers to bear higher rates because utility fixed costs would have to be recovered from a smaller pool of customers. However, the parties raising this concern have provided no evidence to substantiate their claims.[6] To the contrary, recent studies demonstrate that, when other variables in the electricity market are taken into account, retail electric competition does not lead to higher rates. To the contrary, it puts *downward pressure* on retail rates.[7] In that regard, further research demonstrates that every other industry in which competition has been introduced has also seen declining rates.[8]

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addition, attached hereto as Table A-2 is a table that depicts what the legal status of the Electric Competition Rules would be, assuming receipt of the requisite administrative certification from the Arizona Attorney General.

[6] See, January 30, 2009 Comments submitted by Mohave and Navopache Electric Cooperatives, Grand Canyon State Electric Cooperatives Association, Arizona Investment Council, Arizona Transmission Dependent Utility Group, and Tucson Electric Power and UNS Electric.

[7] See January 30, 2009 Comments of Competitive Electric Service Providers, pp. 13 and 18; and Appendix E to those comments: *Texas Retail Competition – Impact on Residential Prices 1995-2008,* Intelometry, December 1, 2008, pps. 25-33.

[8] See January 30, 2009 Comments of Competitive Electric Service Providers, Appendix D: *Embrace Electric Competition or its Déjà vu All Over Again*, The NorthBridge Group, October 2008, p. 5.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

In addition, when discussing "cherry picking," it must be recognized that the "picking" is by the customer, rather than the ESP. Customers are the ones who choose, and some choose alternative providers because they offer a material benefit. Others choose to remain with the utility. The departing customer's choice benefits the utility by offloading that customer's load and forecasted load growth. Moreover, the departing customer's choice benefits the retail customers who choose to remain with the utility, because the utility no longer has the obligation to procure expensive new resources (with their associated long-term fixed costs) to meet the forecasted load for that departing customer.

Some have also argued, again without supporting evidence, that retail electric competition will increase load uncertainty for the utilities, which can increase costs. However, a primary objective of all utility procurement is to implement a comprehensive method for addressing a multitude of uncertainties in load forecasting. Such uncertainties include natural gas prices, economic conditions, weather, transmission system changes, and federal and state policy changes. Because customers' electricity demand changes rapidly, and sometimes unpredictably, utilities are already in the business of evaluating uncertainties of many kinds and procuring a flexible portfolio of resources that can be unwound (or increased) as needed to reflect known conditions. Departing load is just one more uncertainty to be evaluated and addressed in the context of robust load forecasting and developing utility procurement practices that adequately manage those risks.

Further, Arizona utility tariff provisions currently in place require one-year notice for a customer to return to utility service. If the customer fails to provide such notice, the customer is required to pay the utility's incremental cost of service. These provisions were designed both to protect the utility from the risk that it would be unable to recover its costs of serving the returning customer, and to minimize an incentive for customers to return when utility average costs are lower than prevailing market rates. In addition, these provisions protect the utility's remaining customers, who stay on existing utility rates, from subsidizing returning customers.

Regarding the concern that retail electric competition in Arizona will impose additional costs on the utilities for billing changes and tracking customer switching, it is to be noted that

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

these costs already are "sunk" for Arizona Public Service ("APS") Company and Tucson Electric Power ("TEP") Company, having been incurred when the retail markets first opened in Arizona. Nevertheless, both companies have argued that reinstituting direct access will increase systems costs. However, APS provided no estimate of these costs, saying the amount will depend on the market structure and rules adopted by the Commission.[9] On the other hand, TEP argued that it has upgraded its "information technology systems" in the eight years since retail competition was initiated, and yet TEP inexplicably failed to accommodate direct access costs in those upgrades. Further, TEP claimed, without providing any related and substantiated cost estimates, that necessary system modifications would be "expensive" and take "time."[10]

Arizona consumers should not be obligated to suffer further delay in the resumption of retail competition based on speculative cost assertions. If utilities can document significant systems costs, the Commission could elect to phase-in ESP activities, and thereby limit the effect on rates. In that regard, the Commission can begin re-opening the retail market in APS' and TEP's service areas, both of which already had direct access activity before revocation of the previously approved CC&Ns, by granting new CC&Ns to competitive retail electric service providers. In addition, any unrecovered previously-incurred "sunk" costs or new incremental costs could be addressed and justified, if warranted, through utility claims for stranded cost recovery, the mechanisms for which have already been decided in previous proceedings.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

IV.

COMMENT UPON TOPIC 6 IDENTIFIED BY COMMISSION UTILITIES DIVISION STAFF

A. Introduction

Topic 6 in the Commission Staff's March 12, 2010 email request invited comment on "Other Issues Related to Electric Competition." The Merriam Webster Dictionary defines "catch all" as

> ". . . something to hold a variety of odds and ends. . .";[11]

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[9] See Comments of APS, January 30, 2009, p. 4.
[10] See Comments of TEP and UNS Electric, January 30, 2009, p. 4.
[11] See 1997 edition.

and, on the face of it, such a characterization would appear applicable to this topical selection. Accordingly, in the following subsections of this Section IV, the Competitive Electric Service Providers will discuss several additional matters which they believe are directly pertinent to the question of whether retail electric competition should be resumed in Arizona at this point in time.

B. <u>While Arizona Debates, California Moves Forward</u>

1. CALIFORNIA PASSES URGENCY BILL TO LIFT THE SUSPENSION OF RETAIL CHOICE AS OF APRIL 11, 2010

The year 2009 proved to be a landmark year in California for retail choice. The State Legislature lifted the suspension of retail choice and directed the California Public Utilities Commission ("CPUC") to implement measured retail choice in an expedited manner. It was widely acknowledged among policy makers that addressing what was supposed to be a temporary suspension 8-years later was long overdue and not the original intent of the legislature. As part of an overall rate reform package, the California Legislature introduced and, in seven months' time, nearly unanimously approved Senate Bill ("SB") 695. SB 695 allows California businesses additional access to electricity supplies from alternative retail energy suppliers.[12] Moreover, the Legislature enacted SB 695 as an "urgency" bill, which required a 2/3 vote of the legislature for approval. Urgency bills take effect immediately upon signature of the Governor. Appendix A contains the text of the bill, which the California Governor signed into law on October 11, 2009.[13] SB 695 marks an important acknowledgement from the California Legislature following the energy crisis of 2000. By lifting the suspension of direct access that had been in place since September, 2001 and expanding retail energy choice opportunities to all non-residential consumers, up to a predetermined cap, California has now moved beyond the energy crisis and rejoined the fraternity of major industrialized states that have embraced retail choice as an essential aspect of energy policy and wholesale competition.[14]

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[12] The Legislative History for SB 695 is provided in Appendix B hereto, which is incorporated herein by this reference.

[13] See Section 365.1(a) and (b) in Sec. 2 of SB 695, in Appendix A hereto, for the relevant provisions.

[14] Under pre-existing California law, the retail market was closed to new consumers; only those who had previously selected alternative electric providers as of September 20, 2001 were free to continue to shop for power.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

After approval by the Governor, the CPUC took immediate action to implement the bill. On November 18, 2009, a little over a month after the bill was signed into law, the CPUC opened a new sub-phase in its existing proceeding to consider lifting the suspension on retail choice (Rulemaking 07-05-025) and began consideration of the issues addressed in SB 695. On March 11, 2010, less than 5-months following the opening of the new sub-phase of the proceeding, the CPUC unanimously, with little to no comment, and no debate, issued Decision 10-03-022. This decision lifted the 8-year suspension of retail choice to be effective April 11, 2010. A copy of Decision No. 10-03-022 is attached hereto as Appendix C and is incorporated herein by this reference.

In taking such swift action, the California Legislature and CPUC acknowledged that increased levels of participation in retail choice are supported by a "broad coalition of stakeholders."[15] As discussed below, Arizona businesses have also requested acknowledgement of and provision for their right to retail choice in energy procurement, but have so far been rebuffed. The Competitive Electric Service Providers urge the Commission to rejoin the progressive states as has California, and take the necessary steps to immediately move forward with the resumption of retail choice for Arizona.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

2. ARIZONA FALLS FURTHER BEHIND IN THE WEST

Throughout the Western states, businesses are free to decide which energy provider will best meet their individual needs -- California, Washington, Oregon, Nevada, Alberta, Canada, and Baja California, Mexico all have a form of retail choice in-place. Rather than embarking on a dangerous "experiment", as some parties to this proceeding have claimed, in reality, Arizona is lagging behind these other states -- an approach that will likely threaten the overall competitiveness of the Arizona business climate. Retail choice in energy is even more common on the East Coast, where virtually every state north of the Mason-Dixon Line and east of Iowa provide their businesses and residential consumers with retail choice, as described extensively in

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[15] CPUC Press Release issued March 11, 2010, p. 1. A copy of this press release is attached hereto as Appendix D, and is incorporated herein by this reference.

the January 30, 2009 Comments of the Competitive Electric Service Providers filed in this proceeding.[16]

In addition, states throughout the country have implemented many workable models of retail electric competition. In the West, California, Washington and Oregon have a form of retail competition in which the utility distribution company ("UDC") provides default service based on cost-of-service rates, a model that SES contemplates in its Arizona CC&N application. The UDCs in these three Western states procure power for their bundled load under the direct supervision of their regulators, and all non-residential customer classes can elect utility service or competitive retail energy providers.

Moreover, the Western states have made significant strides in promoting markets for renewable energy. The Western Electricity Coordinating Council ("WECC") has established the Western Renewable Energy Generation Information System ("WREGIS'), which is the method by which the Western states track renewable generation and manage compliance with renewable portfolio standards. California and Oregon have already approved WREGIS tracking. On March 11, 2010, the CPUC authorized the use of Tradable Renewable Energy Credits ("TRECs") for both utilities and retail energy suppliers to meet California's Renewable Portfolio Standards.[17]

Once the Commission approves the pending CC&N application of SES, Arizona will be able to join with the other Western states in providing its businesses with retail energy choice, renewable energy options and WREGIS generation tracking. These steps will no doubt improve the competitiveness situation of Arizona business while expanding renewable energy options for its consumers.

C. <u>Arizona's Continued Debate Impairs the Competitiveness of Its Businesses and Denies Significant Benefits to Its Electric Consumers</u>

Arizona's electric business consumers were passionate and direct about their desire for retail choice at the Commission's November 14, 2008 workshop in this proceeding. At its most

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

[16] As discussed above, these January 30th comments provided an extensive description and attached four reports regarding the success of retail electric competition in Canada and the United States.

[17] See CPUC Decision 10-03-021.

fundamental level, end-use customers want to choose electric products and services that best meet their business needs. For some customers, that means increased reliance on renewable energy. For others, it may mean long-term, fixed-price contracts that reduce the risk of future price increases. For still others, it means the ability to structure a package of products and services that can meet corporate objectives for carbon-neutral sustainability. In the end, retail choice allows individual determination of the value proposition for electricity supply. Consumers want to choose their electricity supplier just as they can choose their cell phone company -- in order to manage their own costs and obtain the products and services they need to compete in a global economy.

Indeed, comments filed January 30, 2009 by other parties in this proceeding highlight the significant concerns of Arizona businesses about further delay. The Arizona Retail Association ("ARA") argues that the state's failure to move forward with retail electric competition impairs its members' ability to compete.[18] The Arizona Competitive Power Alliance ("ACPA") adds that continued delay is costly for Arizona consumers.[19] In fact, the ARA finds that the real "risk" to the state is the delay itself, rather than the unsubstantiated claims of risks of higher costs to the consuming public.[20] ARA further argues that the question that should be posed by the Commission's Staff in this proceeding is not "<u>if</u>" retail competition should be offered, but "<u>how</u>."[21]

In their January 30, 2009 comments filed in this proceeding, Arizona businesses and consumers enumerated a lengthy list of benefits they expect to obtain from retail competition. These benefits include:[22]

- More efficient use of resources;
- Downward pressure on electricity prices;
- Reducing uneconomic resource allocation by utilities;

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[18] ARA, Docket No. E-00000A-02-0051, January 30, 2009, p. 2.
[19] ACPA, Docket No. E-00000A-02-0051, January 30, 2009, p. 4.
[20] ARA, *loc. cit.*, p. 1.
[21] ARA, *loc. cit.*, p. 2.
[22] See January 30, 2009 Comments of ARA, ACPA, Residential Utility Consumer Office ("RUCO"), and Freeport McMoRan Copper & Gold and Arizonans for Electric Choice and Competition ("AECC"), Docket No. E-00000A-02-0051.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

- Unleashing creativity and innovation for new energy products, grid management tools, and enhanced technology solutions for energy management;
- Access to renewable energy and Green House Gas ("GHG")-reducing products;
- New pricing options to improve energy efficiency;
- Improved responsiveness and efficiency of utility operations;
- Opportunity for improved customer service from retail energy suppliers;
- Increased job opportunities for Arizonans; and
- Reduced environmental impacts through displacement of older generating units.

Arizona businesses have urged the Commission to move forward with the resumption of retail electric competition and provided a litany of benefits they expect to gain. Moreover, these businesses firmly believe that continued delay hampers their competitive position. The "risk/benefit" debate has been thoroughly vetted.

D. <u>Retail Choice is Critical to Enhancing Renewable Energy Opportunities</u>

Retail choice will significantly enhance renewable energy opportunities for Arizona businesses. The Competitive Electric Service Providers' January 30, 2009 Comments provided extensive evidence on this point.[23] In summary, the evidence demonstrates that retail competition has spurred an explosion in new product offerings and services that were previously unavailable and unthinkable from traditional cost-of-service utilities. These include renewable energy products, sustainable and carbon-neutral energy packages, numerous demand response offerings and energy efficiency services.[24] In fact, a 2008 report assessing retail electricity markets for residential consumers found that retail choice allowed residential consumers to "vote" directly with their dollars. As a result, competitive retail energy suppliers responded with significant offerings of renewable and "green" products in both Texas and New York, example

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

[23] See January 30, 2009 Comments of Competitive Electric Service Providers, *loc. cit.*, pp. 15-16.

[24] See, for example, *Annual Baseline Assessment of Choice in Canada and the United States (ABACCUS) – Commercial and Industrial,* Energy Retailer Research Consortium, December 10, 2008, p. 15. (Attached as Appendix B to the Comments filed January 30, 2009.)

states that have active residential participation in retail energy markets.[25] Clearly, robust retail competition has led to new and innovative product offerings for all customer sizes.

Collectively, the Competitive Electric Service Providers operate in almost every competitive retail energy market in the North America. Their experience is that customers in retail choice programs have greater access to different types and sources of renewable energy and procure higher levels of renewable energy than customers being served by utility sponsored and tariffed, one-size-fits-all, renewable rates. Retail choice allows customers to choose how much renewable energy they wish to buy, as well as the types and the sources of that renewable energy.

Moreover, SES is able to tailor the renewable energy product to meet each customer's individual needs and desires. If its CC&N is approved, SES fully expects to bring not only the minimum Commission-mandated levels of renewable energy to Arizona pursuant to the REST, but also to exceed those levels as a result of customer-driven desires to "green-up" their purchases.

In fact, the 2008 ABACCUS report notes that the societal goals of reducing electricity demand and increasing renewable resources are "ideally suited" to be tackled through competitive energy markets.[26] Businesses are embracing sustainable practices that help them reduce costs, meet consumer demands for "green" companies, and manage business risks in global markets. Seeking products and services in the competitive retail energy market is a necessary tool for consumers and businesses to meet their needs.

E. <u>SES' Application Meets All Statutory Requirements and Should Be Approved Promptly to Bring Arizona's Consumers Long-Delayed Benefits</u>

Approximately <u>four years</u> have passed since SES filed its CC&N application. SES is an active retail supplier in fifteen states, the District of Columbia and Baja California, Mexico, serving over 4,000 MWs of retail load. In fact, SES is larger than most regulated utilities. SES'

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

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[25] *Annual Baseline Assessment of Choice in Canada and the United States (ABACCUS) – Residential,* Energy Retailer Research Consortium, December 10, 2008, p. 19. (Attached as Appendix C to the Comments filed January 30, 2009.)

[26] ABACCUS report for C&I customers, pps. 21-22, attached as Appendix "B" to January 30, 2009 Comments of Competitive Electric Service Providers.

application for a CC&N meets all the statutory requirements and the company is currently positioned to bring a value proposition to Arizona's consumers. There is simply no justification for further delay.

No legal or regulatory obstacles exist to prevent the Commission from considering and acting upon SES' or any other retail energy suppliers' CC&N application at this time. As discussed in Section III(D)(1) above of these Supplemental Comments, the Comments filed January 30, 2009 by the Competitive Electric Service Providers addressed the legal issues in detail[27] and the conditions remain unchanged since that time.

As previously noted, if the Commission wishes to consider substantive and procedural modifications to its current competitive retail electric program, these can be evaluated on a parallel track once the CC&Ns are issued and any changes can be implemented prospectively. Arizona's risks are low, but the potential benefits of moving forward are significant and are of high value. Action is needed now to afford Arizona citizens and customers the products and services they both need and demand in order to compete in today's global economy.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

V.

CONCLUSION

Retail electric competition is clearly in the "public interest." Retail competition is not an "experiment," but a well-documented success story across the country. Arizona is surrounded by states with retail competition and risks lagging further behind as a national and international business competitor.

The Commission has the existing legal authority to approve the applications for CC&Ns submitted by competitive retail electric service providers on a case-by-case basis. In addition, Arizona regulatory and legislative policy decisions have provided the citizens and businesses of this state with a right to choose their electricity providers. There have been no subsequent developments that would warrant taking away or further suspending the realization of this right. Arizona's current rules for retail electric competition are substantively workable and can be used as a starting point for the re-initiation of competition. Once the pending SES CC&N and any

[27] See January 30, 2009 Comments of Competitive Electric Service Providers, *loc. cit.* at Appendix A thereto.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

other currently pending applications have been approved, the Commission can decide whether it wishes to refine its rules prospectively to enhance the success of retail electric competition consistent with established policies to better meet the needs of Arizona's businesses and electric consumers.

As described above, the benefits of moving forward to resume retail electric competition are significant and critical to Arizona's economy. Accordingly, the Competitive Electric Service Providers urge the Commission to move Arizona toward a more competitive and productive future. Specifically, they respectfully request that the Commission:

1. Confirm its previous determination that retail electric competition is in the "public interest" for Arizona and resume retail choice based on the current regulatory model.
2. Concurrently, (a) lift the current suspension on SES' CC&N application, (b) set an expedited schedule for completing the proceeding necessary to consider the application on the merits, and (c) thereafter issue a decision granting SES the CC&N it has requested.
3. Concurrently, submit such retail electric competition rules as may be determined to be necessary to the Attorney General for approval pursuant to the Arizona Administrative Procedure Act.
4. Thereafter, consider such prospective substantive and procedural modifications to the current program for retail electric competition, as determined to be appropriate by the Commission.

Dated this 2nd day of April 2010.

Respectfully submitted,

Lawrence V. Robertson, Jr.

Lawrence V. Robertson, Jr.
Attorney for Sempra Energy Solutions LLC,
Direct Energy LLC, Constellation NewEnergy,
Inc. and Shell Energy North America (US), L.P.

The original and thirteen (13) copies of the foregoing Supplemental Comments will be mailed for filing this 2nd day of April 2010 to:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

A copy of the foregoing Supplemental Comments will be emailed or mailed this 2nd day of April 2010 to:

All Parties of Record

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. Box 1448
Tubac, Arizona 85646
(520) 398-0411

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4/1/2010

Table 1

CURRENT STATUS OF ELECTRIC COMPETITION RULES

REGULATION	STATUS	REASON(S)
R14-2-1601	Valid	Unchallenged
R14-2-1602	Valid	Not subject to Attorney General Review; w/i ACC ratemaking power
R14-2-1603	Invalid	Subject to Attorney General Review; <u>not</u> w/i ACC ratemaking power
R14-2-1604	Valid	Not challenged
R14-2-1605	Invalid	Subject to Attorney General Review; <u>not</u> w/i ACC ratemaking power
R14-2-1606	Valid	Not challenged
R14-2-1607	Valid	Not challenged
R14-2-1608	Valid	Not challenged
R14-2-1609 (A)-(B)	Invalid	Subject to Attorney General Review; <u>not</u> w/i ACC ratemaking power
R14-2-1609 (C)-(J)	Invalid	Not w/i ACC ratemaking power <u>or</u> ARS 40-252
R14-2-1610	Invalid	Subject to Attorney General Review; <u>not</u> w/i ACC ratemaking power
R14-2-1611 (A)	Invalid	Violates Art. 15, Sec. 3 and Art. 15, Sec. 14 Constitutional Requirements
R14-2-1611 (B)-(F)	Valid	Not challenged
R14-2-1612	Invalid	Subject to Attorney General Review; <u>not</u> w/i ACC ratemaking power
R14-2-1613	Valid	Not subject to Attorney General Review; w/i ACC ratemaking power
R14-2-1614	Invalid	Subject to Attorney General Review; <u>not</u> w/i ACC ratemaking power

R14-2-1615 (A) and (C)	Invalid	Not w/i ACC's plenary ratemaking power, and invade utilities' managerial prerogative
R14-2-1615 (B)	Valid	Not challenged
R14-2-1616	Valid	Not subject to Attorney General Review; w/i ACC ratemaking power
R14-2-1617	Invalid	Subject to Attorney General Review; not w/i ACC ratemaking power

Table 2

STATUS OF ELECTRIC COMPETITION RULES
ASSUMING RECEIPT OF ATTORNEY GENERAL CERTIFICATION

REGULATION	STATUS	SUBJECT MATTER DESCRIPTION
R14-2-1601	Valid	Definitions
R14-2-1602	Valid	Commencement of Competition
R14-2-1603	Valid	Certificates of Convenience and Necessity
R14-2-1604	Valid	Competitive Phases
R14-2-1605	Valid	Competitive Services
R14-2-1606	Valid	Services Required to be Made Available
R14-2-1607	Valid	Recovery of Stranded Cost of Affected Utilities
R14-2-1608	Valid	System Benefits Charges
R14-2-1610	Valid	In-state Reciprocity
R14-2-1611 (B)-(F)	Valid	Rates
R14-2-1612	Valid	Service Quality, Consumer Protection, Safety, and Billing Requirements
R14-2-1613	Valid	Reporting Requirements
R14-2-1614	Valid	Administrative Requirements
R14-2-1615 (B)	Valid	Separation of Monopoly and Competitive Services
R14-2-1616	Valid	Code of Conduct
R14-2-1617	Valid	Disclosure of Information

APPENDIX A

CALIFORNIA SENATE BILL 695

APRIL 2, 2010
DOCKET NO. E-00000A-02-0051

Senate Bill No. 695

CHAPTER 337

An act to amend Sections 327, 382, 739.1, and 747 of, and to add Sections 365.1, 739.9, 745, and 748 to, the Public Utilities Code, and to amend Section 80110 of the Water Code, relating to energy, and declaring the urgency thereof, to take effect immediately.

[Approved by Governor October 11, 2009. Filed with Secretary of State October 11, 2009.]

LEGISLATIVE COUNSEL'S DIGEST

SB 695, Kehoe. Energy: rates.

(1) Under existing law, the Public Utilities Commission has regulatory authority over public utilities, including electrical corporations and gas corporations, as defined. Existing law authorizes the commission to fix the rates and charges for every public utility, and requires that those rates and charges be just and reasonable.

This bill would prohibit the commission from requiring or permitting an electrical corporation to do any of the following: (A) employ mandatory or default time-variant pricing, as defined, with or without bill protection, as defined, for residential customers prior to January 1, 2013, (B) employ mandatory or default time-variant pricing, without bill protection, for residential customers prior to January 1, 2014, or (C) employ mandatory or default real-time pricing, without bill protection, for residential customers prior to January 1, 2020. The bill would authorize the commission to authorize an electrical corporation to offer residential customers the option of receiving service pursuant to time-variant pricing and to participate in other demand response programs. The bill would require the commission to only approve an electrical corporation's use of default time-variant pricing for residential customers, beginning January 1, 2014, if those residential customers have the option to not receive service pursuant to time-variant pricing and incur no additional charges, as specified, as a result of the exercise of that option. The bill would exempt certain customers from being subject to default time-variant pricing.

(2) Existing law requires the commission to establish a program of assistance to low-income electric and gas customers, referred to as the California Alternate Rates for Energy or CARE program, and prohibits the cost to be borne solely by any single class of customer.

This bill would require the commission to establish the CARE program to provide assistance to low-income electric and gas customers with annual household incomes that are no greater than 200% of the federal poverty guideline levels, and require that the cost of the program, with respect to electrical corporations, be recovered on an equal cents-per-kilowatthour basis from all classes of customers that were subject to the surcharge that funded the CARE program on January 1, 2008. For a public utility that is both an electrical corporation and a gas corporation, the bill would require that the cost of the program be recovered on an equal cents-per-kilowatthour or per-therm basis from all classes of customers that were subject to the surcharge that funded the CARE program on January 1, 2008.

(3) Existing law relative to electrical restructuring requires that the electrical corporations and gas corporations that participate in the CARE program administer low-income energy efficiency and rate assistance programs described in specified statutes, and undertake certain actions in administering specified energy efficiency and weatherization programs.

This bill would require that electrical corporations, in administering the specified energy efficiency and weatherization programs, target energy efficiency and solar programs to upper-tier and multifamily customers in a manner that will result in long-term permanent reductions in electricity usage at the dwelling units and develop programs that specifically target nonprofit affordable housing providers, including programs that promote weatherization of existing dwelling units and replacement of inefficient appliances. The bill would require the commission, by not later than December 31, 2020, to ensure that all eligible low-income electricity and gas customers are given the opportunity to participate in low-income energy efficiency programs, including customers occupying apartment houses or similar multiunit residential structures, and would require the commission and electrical corporations and gas corporations to expend all reasonable efforts to coordinate ratepayer-funded programs with other energy conservation and efficiency programs and to obtain additional federal funding to support actions undertaken pursuant to this requirement.

(4) Existing law relative to electrical restructuring requires the commission to authorize and facilitate direct transactions between electricity suppliers and retail end-use customers.

Existing law requires the commission to designate a baseline quantity of electricity and gas necessary for a significant portion of the reasonable energy needs of the average residential customer, and requires that electrical and gas corporations file rates and charges, to be approved by the commission, providing baseline rates and requires the commission, in establishing baseline rates, to avoid excessive rate increases for residential customers.

Existing law, enacted during the energy crisis of 2000–01, authorized the Department of Water Resources, until January 1, 2003, to enter into contracts for the purchase of electricity, and to sell electricity to retail end-use customers and, with specified exceptions, local publicly owned electric utilities, at not more than the department's acquisition costs and to recover those costs through the issuance of bonds to be repaid by ratepayers. That law provides that the department is entitled to recover certain expenses resulting from its purchases and sales of electricity and authorizes the commission to enter into an agreement with the department relative to cost recovery. That law prohibits the commission from increasing the electricity charges in effect on February 1, 2001, for residential customers for existing baseline quantities or usage by those customers of up to 130% of then existing baseline quantities, until the department has recovered the costs of electricity it procured for electrical corporation retail end-use customers. That law also suspends the right of retail end-use customers, other than community choice aggregators and a qualifying direct transaction customer, to acquire service through a direct transaction until the Department of Water Resources no longer supplies electricity under that law.

This bill would delete the prohibition that the commission not increase the electricity charges in effect on February 1, 2001, for residential customers for existing baseline quantities or usage by those customers of up to 130% of then existing baseline quantities. The bill would authorize the commission to increase the rates charged residential customers for electricity usage up to 130% of the baseline quantities by the annual percentage change in the Consumer Price Index from the prior year plus 1%, but not less than 3% and not more than 5% per year. This authorization would be subject to the limitation that rates charged residential customers for electricity usage up to the baseline quantities, including any customer charge revenues, not exceed 90% of the system average rate, as defined. The bill would authorize the commission to increase the rates for participants in the CARE program, subject to certain limitations. The bill would delete the existing suspension of direct transactions in the Water Code that was adopted during the energy crisis of 2000–01, and would instead require the commission to authorize direct transactions subject to a reopening schedule that commences immediately and will phase in over a period of not less than 3 years and not more than 5 years, and subject to an annual maximum allowable total kilowatthour limit established, as specified, for each electrical corporation. The bill would continue the suspension of direct transactions except as expressly authorized, until the Legislature, by statute, repeals the suspension or otherwise authorizes direct transactions.

(5) Existing law requires the commission to prepare and submit to the Governor and the Legislature a written report on an annual basis before February 1 of each year on the costs of programs and activities conducted by an electrical corporation or gas corporation that has more than a specified number of customers in California.

This bill would change the reporting date to April 1 of each year. The bill would require that by May 1, 2010, and by May 1 of each year thereafter, the commission also report to the Governor and Legislature with its recommendations for actions that can be undertaken during the upcoming year to limit utility cost and rate increases, consistent with the state's energy and environmental goals, including the state's goals for reducing emissions of greenhouse gases. The bill would require the commission to annually require electrical and gas corporations to study and report to the commission on measures that they recommend be undertaken to limit costs and rate increases.

(6) Under existing law, a violation of the Public Utilities Act or any order, decision, rule, direction, demand, or requirement of the commission is a crime.

Because certain of the provisions of this bill would be a part of the act and because a violation of an order or decision of the commission implementing its requirements would be a crime, the bill would impose a state-mandated local program by creating a new crime.

(7) The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for a specified reason.

(8) This bill would declare that it is to take effect immediately as an urgency statute.

The people of the State of California do enact as follows:

SECTION 1. Section 327 of the Public Utilities Code is amended to read:

327. (a) The electrical corporations and gas corporations that participate in the California Alternate Rates for Energy (CARE) program, as established pursuant to Section 739.1, shall administer low-income energy efficiency and rate assistance programs described in Sections 382, 739.1, 739.2, and 2790, subject to commission oversight. In administering the programs described in Section 2790, the electrical corporations and gas corporations, to the extent practicable, shall do all of the following:

(1) Continue to leverage funds collected to fund the program described in subdivision (a) with funds available from state and federal sources.

(2) Work with state and local agencies, community-based organizations, and other entities to ensure efficient and effective delivery of programs.

(3) Encourage local employment and job skill development.

(4) Maximize the participation of eligible participants.

(5) Work to reduce consumers electric and gas consumption, and bills.

(6) For electrical corporations, target energy efficiency and solar programs to upper-tier and multifamily customers in a manner that will result in long-term permanent reductions in electricity usage at the dwelling units, and develop programs that specifically target nonprofit affordable housing providers, including programs that promote weatherization of existing dwelling units and replacement of inefficient appliances.

(7) For electrical corporations and for public utilities that are both electrical corporations and gas corporations, allocate the costs of the CARE program on an equal cents per kilowatthour or equal cents per therm basis to all classes of customers that were subject to the surcharge that funded the program on January 1, 2008.

(b) If the commission requires low-income energy efficiency programs to be subject to competitive bidding, the electrical and gas corporations described in subdivision (a), as part of their bid evaluation criteria, shall consider both cost-of-service criteria and quality-of-service criteria. The bidding criteria, at a minimum, shall recognize all of the following factors:

(1) The bidder's experience in delivering programs and services, including, but not limited to, weatherization, appliance repair and maintenance, energy education, outreach and enrollment services, and bill payment assistance programs to targeted communities.

(2) The bidder's knowledge of the targeted communities.

(3) The bidder's ability to reach targeted communities.

(4) The bidder's ability to utilize and employ people from the local area.

(5) The bidder's general contractor's license and evidence of good standing with the Contractors' State License Board.

(6) The bidder's performance quality as verified by the funding source.

(7) The bidder's financial stability.

(8) The bidder's ability to provide local job training.

(9) Other attributes that benefit local communities.

(c) Notwithstanding subdivision (b), the commission may modify the bid criteria based upon public input from a variety of sources, including representatives from low-income communities and the program administrators identified in subdivision (b), in order to ensure the effective and efficient delivery of high quality low-income energy efficiency programs.

SEC. 2. Section 365.1 is added to the Public Utilities Code, to read:

365.1. (a) Except as expressly authorized by this section, and subject to the limitations in subdivisions (b) and (c), the right of retail end-use customers pursuant to this chapter to acquire service from other providers is suspended until the Legislature, by statute, lifts the suspension or otherwise authorizes direct transactions. For purposes of this section, "other provider" means any person, corporation, or other entity that is authorized to provide electric service within the service territory of an electrical corporation pursuant to this chapter, and includes an aggregator, broker, or marketer, as defined in Section 331, and an electric service provider, as defined in Section 218.3. "Other provider" does not include a community choice aggregator, as defined in Section 331.1, and the limitations in this section do not apply to the sale of electricity by "other providers" to a community choice aggregator for resale to community choice aggregation electricity consumers pursuant to Section 366.2.

(b) The commission shall allow individual retail nonresidential end-use customers to acquire electric service from other providers in each electrical corporation's distribution service territory, up to a maximum allowable total kilowatthours annual limit. The maximum allowable annual limit shall be established by the commission for each electrical corporation at the maximum total kilowatthours supplied by all other providers to distribution customers of that electrical corporation during any sequential 12-month period between April 1, 1998, and the effective date of this section. Within six months of the effective date of this section, or by July 1, 2010, whichever is sooner, the commission shall adopt and implement a reopening schedule that commences immediately and will phase in the allowable amount of increased kilowatthours over a period of not less than three years, and not more than five years, raising the allowable limit of kilowatthours supplied by other providers in each electrical corporation's distribution service territory from the number of kilowatthours provided by other providers as of the effective date of this section, to the maximum allowable annual limit for that electrical corporation's distribution service territory. The commission shall review and, if appropriate, modify its currently effective rules governing direct transactions, but that review shall not delay the start of the phase-in schedule.

(c) Once the commission has authorized additional direct transactions pursuant to subdivision (b), it shall do both of the following:

(1) Ensure that other providers are subject to the same requirements that are applicable to the state's three largest electrical corporations under any programs or rules adopted by the commission to implement the resource adequacy provisions of Section 380, the renewables portfolio standard provisions of Article 16 (commencing with Section 399.11), and the requirements for the electricity sector adopted by the State Air Resources Board pursuant to the California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500) of the Health and Safety Code). This requirement applies notwithstanding any prior decision of the commission to the contrary.

(2) (A) Ensure that, in the event that the commission authorizes, in the situation of a contract with a third party, or orders, in the situation of utility-owned generation, an electrical corporation to obtain generation resources that the commission determines are needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation's distribution service territory, the net capacity costs of those generation resources are allocated on a fully nonbypassable basis consistent with departing load provisions as determined by the commission, to all of the following:

(i) Bundled service customers of the electrical corporation.

(ii) Customers that purchase electricity through a direct transaction with other providers.

(iii) Customers of community choice aggregators.

(B) The resource adequacy benefits of generation resources acquired by an electrical corporation pursuant to subparagraph (A) shall be allocated to all customers who pay their net capacity costs. Net capacity costs shall be determined by subtracting the energy and ancillary services value of the resource from the total costs paid by the electrical corporation pursuant to a contract with a third party or the annual revenue requirement for the resource if the electrical corporation directly owns the resource. An energy auction shall not be required as a condition for applying this allocation, but may be allowed as a means to establish the energy and ancillary services value of the resource for purposes of determining the net costs of capacity to be recovered from customers pursuant to this paragraph, and the allocation of the net capacity costs of contracts with third parties shall be allowed for the terms of those contracts.

(C) It is the intent of the Legislature, in enacting this paragraph, to provide additional guidance to the commission with respect to the implementation of subdivision (g) of Section 380, as well as to ensure that the customers to whom the net costs and benefits of capacity are allocated are not required to pay for the cost of electricity they do not consume.

(d) (1) If the commission approves a centralized resource adequacy mechanism pursuant to subdivisions (h) and (i) of Section 380, upon the implementation of the centralized resource adequacy mechanism the requirements of paragraph (2) of subdivision (c) shall be suspended. If the commission later orders that electrical corporations cease procuring capacity through a centralized resource adequacy mechanism, the requirements of paragraph (2) of subdivision (c) shall again apply.

(2) If the use of a centralized resource adequacy mechanism is authorized by the commission and has been implemented as set forth in paragraph (1), the net capacity costs of generation resources that the commission determines are required to meet urgent system or urgent local grid reliability needs, and that the commission authorizes to be procured outside of the Section 380 or Section 454.5 processes, shall be recovered according to the provisions of paragraph (2) of subdivision (c).

(3) Nothing in this subdivision supplants the resource adequacy requirements of Section 380 or the resource procurement procedures established in Section 454.5.

(e) The commission may report to the Legislature on the efficacy of authorizing individual retail end-use residential customers to enter into direct transactions, including appropriate consumer protections.

SEC. 3. Section 382 of the Public Utilities Code is amended to read:

382. (a) Programs provided to low-income electricity customers, including, but not limited to, targeted energy-efficiency services and the California Alternate Rates for Energy program shall be funded at not less than 1996 authorized levels based on an assessment of customer need.

(b) In order to meet legitimate needs of electric and gas customers who are unable to pay their electric and gas bills and who satisfy eligibility criteria for assistance, recognizing that electricity is a basic necessity, and that all residents of the state should be able to afford essential electricity and gas supplies, the commission shall ensure that low-income ratepayers are not jeopardized or overburdened by monthly energy expenditures. Energy expenditure may be reduced through the establishment of different rates for low-income ratepayers, different levels of rate assistance, and energy efficiency programs.

(c) Nothing in this section shall be construed to prohibit electric and gas providers from offering any special rate or program for low-income ratepayers that is not specifically required in this section.

(d) Beginning in 2002, an assessment of the needs of low-income electricity and gas ratepayers shall be conducted periodically by the commission with the assistance of the Low-Income Oversight Board. The assessment shall evaluate low-income program implementation and the effectiveness of weatherization services and energy efficiency measures in low-income households. The assessment shall consider whether existing programs adequately address low-income electricity and gas customers' energy expenditures, hardship, language needs, and economic burdens.

(e) The commission shall, by not later than December 31, 2020, ensure that all eligible low-income electricity and gas customers are given the opportunity to participate in low-income energy efficiency programs, including customers occupying apartments or similar multiunit residential structures. The commission and electrical corporations and gas corporations shall make all reasonable efforts to coordinate ratepayer-funded programs with other energy conservation and efficiency programs and to obtain additional federal funding to support actions undertaken pursuant to this subdivision.

These programs shall be designed to provide long-term reductions in energy consumption at the dwelling unit based on an audit or assessment of the dwelling unit, and may include improved insulation, energy efficient appliances, measures that utilize solar energy, and other improvements to the physical structure.

(f) The commission shall allocate funds necessary to meet the low-income objectives in this section.

SEC. 4. Section 739.1 of the Public Utilities Code is amended to read:

739.1. (a) As used in this section, the following terms have the following meanings:

(1) "Baseline quantity" has the same meaning as defined in Section 739.

(2) "California Solar Initiative" means the program providing ratepayer funded incentives for eligible solar energy systems adopted by the commission in Decision 05-12-044 and Decision 06-01-024, as modified by Article 1 (commencing with Section 2851) of Chapter 9 of Part 2 and Chapter 8.8 (commencing with Section 25780) of Division 15 of the Public Resources Code.

(3) "CalWORKs program" means the program established pursuant to the California Work Opportunity and Responsibility to Kids Act (Chapter 2 (commencing with Section 11200) of Part 3 of Division 9 of the Welfare and Institutions Code).

(4) "Public goods charge" means the nonbypassable separate rate component imposed pursuant to Article 7 (commencing with Section 381) of Chapter 2.3 and the nonbypassable system benefits charge imposed pursuant to the Reliable Electric Service Investments Act (Article 15 (commencing with Section 399) of Chapter 2.3).

(b) (1) The commission shall establish a program of assistance to low-income electric and gas customers with annual household incomes that are no greater than 200 percent of the federal poverty guideline levels, the cost of which shall not be borne solely by any single class of customer. The program shall be referred to as the California Alternate Rates for Energy or CARE program. The commission shall ensure that the level of discount for low-income electric and gas customers correctly reflects the level of need.

(2) The commission may, subject to the limitation in paragraph (4), increase the rates in effect for CARE program participants for electricity usage up to 130 percent of baseline quantities by the annual percentage increase in benefits under the CalWORKs program as authorized by the Legislature for the fiscal year in which the rate increase would take effect, but not to exceed 3 percent per year.

(3) Beginning January 1, 2019, the commission may, subject to the limitation in paragraph (4), establish rates for CARE program participants pursuant to this section and Sections 739 and 739.9, subject to both of the following:

(A) The requirements of subdivision (b) of Section 382 that the commission ensure that low-income ratepayers are not jeopardized or overburdened by monthly energy expenditures.

(B) The requirement that the level of the discount for low-income electricity and gas ratepayers correctly reflects the level of need as determined by the needs assessment conducted pursuant to subdivision (d) of Section 382.

(4) Tier 1, tier 2, and tier 3 CARE rates shall not exceed 80 percent of the corresponding tier 1, tier 2, and tier 3 rates charged to residential customers not participating in the CARE program, excluding any Department of Water Resources bond charge imposed pursuant to Division 27 (commencing with Section 80000) of the Water Code, the CARE surcharge portion of the public goods charge, any charge imposed pursuant to the California Solar Initiative, and any charge imposed to fund any other program that exempts CARE participants from paying the charge.

(5) Rates charged to CARE program participants shall not have more than three tiers. An electrical corporation that does not have a tier 3 CARE rate may introduce a tier 3 CARE rate that, in order to moderate the impact on program participants whose usage exceeds 130 percent of baseline quantities, shall be phased in to 80 percent of the corresponding rates charged to residential customers not participating in the CARE program, excluding any Department of Water Resources bond charge imposed pursuant to Division 27 (commencing with Section 80000) of the Water Code, the CARE surcharge portion of the public goods charge, any charge imposed pursuant to the California Solar Initiative, and any other charge imposed to fund a program that exempts CARE participants from paying the charge. For an electrical corporation that does not have a tier 3 CARE rate that introduces a tier 3 CARE rate, the initial rate shall be no more than 150 percent of the CARE baseline rate. Any additional revenues collected by an electrical corporation resulting from the adoption of a tier 3 CARE rate shall, until the utility's next periodic general rate case review of cost allocation and rate design, be credited to reduce rates of residential ratepayers not participating in the CARE program with usage above 130 percent of baseline quantities.

(c) The commission shall work with the public utility electrical and gas corporations to establish penetration goals. The commission shall authorize recovery of all administrative costs associated with the implementation of the CARE program that the commission determines to be reasonable, through a balancing account mechanism. Administrative costs shall include, but are not limited to, outreach, marketing, regulatory compliance, certification and verification, billing, measurement and evaluation, and capital improvements and upgrades to communications and processing equipment.

(d) The commission shall examine methods to improve CARE enrollment and participation. This examination shall include, but need not be limited to, comparing information from CARE and the Universal Lifeline Telephone Service (ULTS) to determine the most effective means of utilizing that information to increase CARE enrollment, automatic enrollment of ULTS customers who are eligible for the CARE program, customer privacy issues, and alternative mechanisms for outreach to potential enrollees. The commission shall ensure that a customer consents prior to enrollment. The commission shall consult with interested parties, including ULTS providers, to develop the best methods of informing ULTS customers about other available low-income programs, as well as the best mechanism for telephone providers to recover reasonable costs incurred pursuant to this section.

(e) (1) The commission shall improve the CARE application process by cooperating with other entities and representatives of California government, including the California Health and Human Services Agency and the Secretary of California Health and Human Services, to ensure that all gas and electric customers eligible for public assistance programs in California that reside within the service territory of an electrical corporation or gas corporation, are enrolled in the CARE program. To the extent practicable, the commission shall develop a CARE application process using the existing ULTS application process as a model. The commission shall work with public utility electrical and gas corporations and the Low-Income Oversight Board established in Section 382.1 to meet the low-income objectives in this section.

(2) The commission shall ensure that an electrical corporation or gas corporation with a commission-approved program to provide discounts based upon economic need in addition to the CARE program, including a Family Electric Rate Assistance program, utilize a single application form, to enable an applicant to alternatively apply for any assistance program for which the applicant may be eligible. It is the intent of the Legislature to allow applicants under one program, that may not be eligible under that program, but that may be eligible under an alternative assistance program based upon economic need, to complete a single application for any commission-approved assistance program offered by the public utility.

(f) The commission's program of assistance to low-income electric and gas customers shall, as soon as practicable, include nonprofit group living facilities specified by the commission, if the commission finds that the residents in these facilities substantially meet the commission's low-income eligibility requirements and there is a feasible process for certifying that the assistance shall be used for the direct benefit, such as improved quality of care or improved food service, of the low-income residents in the facilities. The commission shall authorize utilities to offer discounts to eligible facilities licensed or permitted by appropriate state or local agencies, and to facilities, including women's shelters, hospices, and homeless shelters, that may not have a license or permit but provide other proof satisfactory to the utility that they are eligible to participate in the program.

(g) It is the intent of the Legislature that the commission ensure CARE program participants are afforded the lowest possible electric and gas rates and, to the extent possible, are exempt from additional surcharges attributable to the energy crisis of 2000–01.

SEC. 5. Section 739.9 is added to the Public Utilities Code, to read:

739.9. (a) The commission may, subject to the limitation in subdivision (b), increase the rates charged residential customers for electricity usage up to 130 percent of the baseline quantities, as defined in Section 739, by the annual percentage change in the Consumer Price Index from the prior year plus 1 percent, but not less than 3 percent and not more than 5 percent per year. For purposes of this subdivision, the annual percentage change in the Consumer Price Index shall be calculated using the same formula that was used to determine the annual Social Security Cost of Living Adjustment on January 1, 2008. This subdivision shall become inoperative on January 1, 2019, unless a later enacted statute deletes or extends that date.

(b) The rates charged residential customers for electricity usage up to the baseline quantities, including any customer charge revenues, shall not exceed 90 percent of the system average rate prior to January 1, 2019, and may not exceed 92.5 percent after that date. For purposes of this subdivision, the system average rate shall be determined by dividing the electrical corporation's total revenue requirements for bundled service customers by the adopted forecast of total bundled service sales.

(c) This section does not require the commission to increase any residential rate or place any restriction upon, or otherwise limit, the authority of the commission to reduce any residential rate.

SEC. 6. Section 745 is added to the Public Utilities Code, to read:

745. (a) For purposes of this section, the following terms have the following meanings:

(1) "Bill protection" means that customers on mandatory or default time-variant pricing will be guaranteed that the total amount paid for electric service shall not exceed the amount that would have been due under the customer's previous rate schedule.

(2) "Time-variant pricing" includes time-of-use rates, critical peak pricing, and real-time pricing, but does not include programs that provide customers with discounts from standard tariff rates as an incentive to reduce consumption at certain times, including peak time rebates.

(b) The commission shall not require or permit an electrical corporation to do any of the following:

(1) Employ mandatory or default time-variant pricing, with or without bill protection, for any residential customer prior to January 1, 2013.

(2) Employ mandatory or default time-variant pricing, without bill protection, for residential customers prior to January 1, 2014.

(3) Employ mandatory or default real-time pricing, without bill protection, for residential customers prior to January 1, 2020.

(c) The commission may, at any time, authorize an electrical corporation to offer residential customers the option of receiving service pursuant to time-variant pricing and to participate in other demand response programs.

(d) On and after January 1, 2014, the commission shall only approve an electrical corporation's use of default time-variant pricing in a manner consistent with the other provisions of this part, if all of the following conditions have been met:

(1) Residential customers have the option to not receive service pursuant to time-variant pricing and incur no additional charges as a result of the exercise of that option. Prohibited charges include, but are not limited to, administrative fees for switching away from time-variant pricing, hedging premiums that exceed any actual costs of hedging, and more than a proportional share of any discounts or other incentives paid to customers to increase participation in time-variant pricing. This prohibition on additional charges is not intended to ensure that a customer will necessarily experience a lower total bill as a result of the exercise of the option to not receive service pursuant to a time-variant rate schedule.

(2) Residential customers receiving a medical baseline allowance pursuant to subdivision (c) of Section 739 and customers requesting third-party notification pursuant to subdivision (c) of Section 779.1, shall not be subject to mandatory or default time-variant pricing.

(3) A residential customer shall not be subject to a default time-variant rate schedule without bill protection unless that residential customer has been provided with not less than one year of interval usage data from an advanced meter and associated customer education and, following the passage of this period, is provided with not less than one year of bill protection during which the total amount paid by the residential customer for electric service shall not exceed the amount that would have been payable by the residential customer under that customer's previous rate schedule.

SEC. 7. Section 747 of the Public Utilities Code is amended to read:

747. (a) It is the intent of the Legislature that the commission reduce rates for electricity and natural gas to the lowest amount possible.

(b) The commission shall prepare a written report on the costs of programs and activities conducted by each electrical corporation and gas corporation that is subject to this section, including activities conducted to comply with their duty to serve. The report shall be completed on an annual basis before April 1 of each year, and shall identify, clearly and concisely, all of the following:

(1) Each program mandated by statute and its annual cost to ratepayers.

(2) Each program mandated by the commission and its annual cost to ratepayers.

(3) Energy purchase contract costs and bond-related costs incurred pursuant to Division 27 (commencing with Section 80000) of the Water Code.

(4) All other aggregated categories of costs currently recovered in retail rates as determined by the commission.

(c) As used in this section, the reporting requirements apply to electrical corporations with at least 1,000,000 retail customers in California and gas corporations with at least 500,000 retail customers in California.

(d) The report required by subdivision (b) shall be submitted to the Governor and the Legislature no later than April 1 of each year.

(e) The commission shall post the report required by subdivision (b) in a conspicuous area of its Internet Web site.

SEC. 8. Section 748 is added to the Public Utilities Code, to read:

748. (a) The commission, by May 1, 2010, and by each May 1 thereafter, shall prepare and submit a written report, separate from and in addition to the report required by Section 747, to the Governor and Legislature that contains the commission's recommendations for actions that can be undertaken during the succeeding 12 months to limit utility cost and rate increases, consistent with the state's energy and environmental goals, including goals for reducing emissions of greenhouse gases.

(b) In preparing the report required by subdivision (a), the commission shall require electrical corporations with 1,000,000 or more retail customers in California, and gas corporations with 500,000 or more retail customers in California, to study and report on measures the corporation recommends be undertaken to limit costs and rate increases.

(c) The commission shall post the report required by subdivision (a) in a conspicuous area of its Internet Web site.

SEC. 9. Section 80110 of the Water Code is amended to read:

80110. (a) The department shall retain title to all electricity sold by it to the retail end-use customers. The department shall be entitled to recover, as a revenue requirement, amounts and at the times necessary to enable it to comply with Section 80134, and shall advise the commission as the department determines to be appropriate.

(b) The revenue requirements may also include any advances made to the department hereunder or hereafter for purposes of this division, or from the Department of Water Resources Electric Power Fund, and General Fund moneys expended by the department pursuant to the Governor's Emergency Proclamation dated January 17, 2001.

(c) (1) For the purposes of this division and except as otherwise provided in this section, the Public Utility Commission's authority as set forth in Section 451 of the Public Utilities Code shall apply, except any just and reasonable review under Section 451 shall be conducted and determined by the department. Prior to the execution of any modification of any contract for the purchase of electricity by the department pursuant to this division, on or after the effective date of this section, the department or the commission, as applicable, shall do the following:

(A) The department shall notify the public of its intent to modify a contract and the opportunity to comment on the proposed modification.

(B) At least 21 days after providing public notice, the department shall make a determination as to whether the proposed modifications are just and reasonable. The determination shall include responses to any public comments.

(C) No later than 70 days before the date of execution of the contract modification, the department shall provide a written report to the commission setting forth the justification for the determination that the proposed modification is just and reasonable, including documents, analysis, response to public comments, and other information relating to the determination.

(D) Within 60 days of the date of receipt of the department's written report, the commission shall review the report and make public its comments. If the commission in its comments recommends against the proposed modification, the department shall not execute the proposed contract modification.

(2) This subdivision does not apply to the modification of a contract modified to settle litigation to which the commission is a party.

(3) This subdivision does not apply to the modification of a contract for the purchase of electricity that is generated from a facility owned by a public agency if the contract requires the public agency to sell electricity to the department at or below the public agency's cost of that electricity.

(4) This subdivision does not apply to the modification of a contract to address issues relating to billing, scheduling, delivery of electricity, and related contract matters arising out of the implementation by the Independent System Operator of its market redesign and technology upgrade program.

(5) (A) For purposes of this subdivision, the department proposes to "modify" a contract if there is any material change proposed in the terms of the contract.

(B) A change to a contract is not material if it is only administrative in nature or the change in ratepayer value results in ratepayer savings, not to exceed twenty-five million dollars ($25,000,000) per year. For the purpose of making a determination that a change is only administrative in nature or results in ratepayer savings of twenty-five million dollars ($25,000,000) or less per year, the executive director of the commission shall concur in writing with each of those determinations by the department.

(d) The commission may enter into an agreement with the department with respect to charges under Section 451 for purposes of this division, and that agreement shall have the force and effect of a financing order adopted in accordance with Article 5.5 (commencing with Section 840) of Chapter 4 of Part 1 of Division 1 of the Public Utilities Code, as determined by the commission.

(e) The department shall have the same rights with respect to the payment by retail end-use customers for electricity sold by the department as do providers of electricity to the customers.

SEC. 10. No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because the only costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

SEC. 11. This act is an urgency statute necessary for the immediate preservation of the public peace, health, or safety within the meaning of Article IV of the Constitution and shall go into immediate effect. The facts constituting the necessity are:

In order to avert a rate crisis involving unfair and unreasonable rates being charged for electric and gas service by electrical and gas corporations, it is necessary that this act take effect immediately.

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APPENDIX B

BILL HISTORY – CALIFORNIA SENATE BILL 695

APRIL 2, 2010
DOCKET NO. E-00000A-02-0051

COMPLETE BILL HISTORY

BILL NUMBER : S.B. No. 695
AUTHOR : Kehoe
TOPIC : Energy: rates.

TYPE OF BILL :
Inactive
Urgency
Non-Appropriations
2/3 Vote Required
State-Mandated Local Program
Fiscal
Non-Tax Levy

BILL HISTORY
2009
Oct. 11 Chaptered by Secretary of State. Chapter 337, Statutes of 2009.
Oct. 11 Approved by Governor.
Sept. 25 Enrolled. To Governor at 1 p.m.
Sept. 8 Senate concurs in Assembly amendments. (Ayes 39. Noes 0. Page 2282.) To enrollment.
Sept. 2 In Senate. To unfinished business.
Sept. 1 Read third time. Urgency clause adopted. Passed. (Ayes 76. Noes 1. Page 2857.) To Senate.
Aug. 24 Read second time. To third reading.
Aug. 20 From committee: Do pass. (Ayes 16. Noes 0.) (Heard in committee on August 19.)
Aug. 17 From committee with author's amendments. Read second time. Amended. Re-referred to Com. on APPR.
June 30 From committee: Do pass, but first be re-referred to Com. on APPR. (Ayes 14. Noes 0.) Re-referred to Com. on APPR. (Heard in committee on June 29.)
June 24 From committee with author's amendments. Read second time. Amended. Re-referred to Com. on U. & C. (Corrected June 29.)
June 22 Set, first hearing. Further hearing to be set.
June 15 To Com. on U. & C.
June 1 In Assembly. Read first time. Held at Desk.
June 1 Read third time. Urgency clause adopted. Passed. (Ayes 37. Noes 0. Page 1103.) To Assembly.
May 28 From committee: Do pass as amended. (Ayes 11. Noes 0. Page 1074.) Read second time. Amended. To third reading.
May 22 Set for hearing May 28. (Suspense - for vote only.)
May 18 Placed on APPR suspense file.
May 8 Set for hearing May 18.
Apr. 29 Read second time. Amended. Re-referred to Com. on APPR.
Apr. 28 From committee: Do pass as amended, but first amend, and re-refer to Com. on APPR. (Ayes 11. Noes 0. Page 584.)
Apr. 13 From committee with author's amendments. Read second time. Amended. Re-referred to Com. on E., U., & C.
Mar. 25 Set for hearing April 21.
Mar. 19 To Com. on E., U. & C.
Mar. 2 Read first time.
Feb. 28 From print. May be acted upon on or after March 30.
Feb. 27 Introduced. To Com. on RLS. for assignment. To print.

APPENDIX C

CALIFORNIA PUBLIC UTILITIES COMMISSION
DECISION NUMBER 10-02-022

DECISION REGARDING INCREASED LIMITS FOR DIRECT ACCESS TRANSACTIONS

APRIL 2, 2010
DOCKET NO. E-00000A-02-0051

ALJ/TRP/jt2 **Date of Issuance 3/15/2010**

Decision 10-03-022 March 11, 2010

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Rulemaking regarding whether, or subject to what Conditions, the suspension of Direct Access may be lifted consistent with Assembly Bill 1X and Decision 01-09-060.	Rulemaking 07-05-025 (Filed May 24, 2007)

DECISION REGARDING INCREASED LIMITS FOR DIRECT ACCESS TRANSACTIONS

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DECISION REGARDING INCREASED LIMITS FOR DIRECT ACCESS TRANSACTIONS

1. Summary

By this decision, we authorize and implement a plan for increased limits in the allowed level of direct access (DA) transactions within the service territories of California's three major investor-owned electric utilities: Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric.

The authorization for increased limits in DA transactions is implemented in accordance with the provisions of Senate Bill (SB) 695 (Stats. 2009, ch. 337). Among other issues, SB 695 amends the previously effective suspension of DA, and requires the Commission to authorize increases in the maximum kilowatt-hour limit on DA transactions. Effective April 11, 2010, all qualifying customers will be eligible to take DA service, up to the new maximum cap subject to the conditions as set forth herein. The increased DA allowances shall be phased in over a four-year period, subject to annual caps in the maximum DA increase allowed each year. DA remains suspended, except as provided by this decision implementing SB 695. Existing rules and processes currently in place for DA service shall remain in place, except for changes specified herein as necessary to implement the provisions of SB 695.

This decision only addresses those implementation issues that must be resolved in order to begin the process of new enrollments of DA load effective April 11, 2010. Additional issues that relate to SB 695 implementation will be addressed expeditiously in a subsequent decision.

2. Background

Through direct access (DA), eligible retail customers have the choice to purchase electric power directly from an independent electric service provider (ESP) rather than only through an investor-owned utility (IOU). DA was first instituted as an option for retail electric service in 1998, as part of an industry restructuring program to bring retail competition to California electric power markets.[1]

The electric industry restructuring program was cut short, however, by the events of 2000-2001 which led to extraordinary wholesale power cost increases, threatening the solvency of California's major electric utilities and the reliability of electric service. On February 1, 2001, AB 1 from the First Extraordinary Session (Ch. 4, First Extraordinary Session 2001) (AB1X) was signed into law, implementing measures to address the energy crisis. Among other measures, AB1X required the California Department of Water Resources (DWR) to procure electric power supplies sufficient to meet the net short for customers of the IOUs.[2]

DWR formally began procuring electric power for customers in the service territories of the three major IOUs in early 2001. AB1X authorized DWR to recover its power costs from electric charges established by the Commission. (Water Code § 80110.)

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[1] *See* Decision (D.) 95-12-063, as modified by D.96-01-009 (1995) 64 Cal. PUC 2d 1, 24 (Preferred Policy Decision). The Legislature codified the Preferred Policy Decision in Assembly Bill (AB) 1890 (Stats. 1996, ch. 854) (AB 1890).

[2] The net short is the difference between customer loads and the power already under contract to the utilities or generated from a utility-owned asset.

To ensure that DWR procurement costs were assigned fairly and recovered from a stable customer base, the Legislature, among other measures, suspended the DA program. Pursuant to AB1X, the Commission suspended the right to enter into new contracts for DA after September 20, 2001,[3] permitting no new DA contracts, but allowing preexisting contracts to continue in effect. The Commission opened this proceeding to investigate conditions whereby DA may be reinstituted in the future, although the suspension has continued in effect up until the present time.

On October 11, 2009, Senate Bill (SB) 695 was signed into law as an urgency statute. SB 695 adds Section 365.1 (b) to the Public Utilities Code, which states in pertinent part:

> The commission shall allow individual retail nonresidential end-use customers to acquire electric service from other providers in each electrical corporation's distribution service territory, up to a maximum allowable total kilowatt hours annual limit.

Except for this express authorization for increased DA transactions under SB 695, the previously enacted suspension of DA transactions remains in effect until repealed by legislation, or until additional DA transactions are otherwise authorized.

Within six months from the effective date of SB 695[4] or July 1, 2010, whichever is sooner, the Commission must adopt and implement a schedule to begin the phase-in of authorized increases in the maximum amount of DA transactions over a period of at least three years, but not more than five years.

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[3] *See* D.01-09-060 and Pub. Util. Code §§ 366 or 366.5.

[4] SB 695 was chaptered on October 11, 2009 and as urgency legislation, took effect immediately. Six months from the effective date of SB 695 is April 11, 2010.

The allowable limit of DA power supplied by other providers in each electric utility's distribution service territory will be increased to the maximum allowable annual limit for that utility's distribution service territory as of the effective date of SB 695. The Commission may, if appropriate, modify its currently effective rules governing DA transactions, but such review shall not delay the phase-in schedule.

In order to expeditiously implement SB695, the assigned Commissioner initiated this sub-phase of the proceeding by issuing a ruling amending the scope of this proceeding to address issues as necessary for implementing the provisions of SB 695 relating to DA. By ruling dated November 18, 2009, the assigned Commissioner identified the pertinent DA provisions of SB 695 to be addressed in this proceeding, and established a schedule to meet the SB 695 timing requirements. Parties filed comments on the scope of issues to be addressed in this sub-phase on December 7, 2009. The assigned Commissioner issued a ruling modifying the scope of issues to be addressed by ruling dated December 17, 2009. The record was developed through the filing of written comments, with one workshop. No evidentiary hearings were necessary.

Substantive comments were filed on January 5, 2010.[5] A workshop was convened on January 11, 2010, to facilitate discussion and seek consensus on issues in dispute. Reply comments were filed on February 1, 2010.

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[5] Opening Comments and/or reply comments were filed by the California Alliance for Choice in Energy Solutions and the Alliance for Retail Energy Markets (CACES/AReM), the Direct Access Customer Coalition (DACC), Pacific Gas and Electric Company (PG&E), BP America (BP), the California Large Energy Consumers Association (CLECA), California Manufacturers and Technology Association (CMTA), Commercial Energy of California (CEC), the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), the Natural Resources Defense Council (NRDC),

Footnote continued on next page

3. Authorized Increases for Direct Access Cap

We herein authorize increased limits on the maximum level of DA transactions that may be allowed beginning effective April 11, 2010[6]. The basis for the increased allowances is prescribed by Sec. 365.1 which states that the maximum limit:

> ... shall be established by the commission for each electrical corporation at the **maximum total kilowatt hours supplied by all other providers to distribution customers of that electrical corporation** during any sequential 12-month period between April 1, 1998, and the effective date of this section. (Emphasis added.)

The statute defines "other provider" as any person, corporation, or other entity that is authorized to provide electric service within the service territory of the electrical corporation, but does not include sales to or by a community choice aggregator. Individual retail non-residential end-use customers in an electrical corporation's service territory will be allowed to acquire electric service from providers other than the electrical corporation up to a maximum total kilowatt hour (kWh) annual limit. In response to the Administrative Law Judge (ALJ) ruling issued November 18, 2009, each of the IOUs provided the relevant data identifying the applicable amount of DA load subject to the increased DA cap pursuant to the requirements of SB 695.

Southern California Edison Company (SCE), the Safeway Parties (Safeway), San Diego Gas & Electric Company (SDG&E), Silicon Valley Leadership Group, School Project for Utility Rate Reduction, the California State Universities, and Customized Energy Solutions, LTD.

[6] The implementation date of April 11, 2010 represents the time limit required to begin implementation under SB 695, representing six months from the statute's effective date.

The IOUs and the Commission's Energy Division provided clarification at the workshop of the differences between the numbers in the December 3, 2009 and December 29, 2009, informational filings and the numbers provided in the IOUs' monthly DA activity reports. The general consensus among parties at the workshop was that formal independent verification of the data submitted by the IOUs was not necessary, and that the time required to implement such verification process could unduly delay the reopening of DA. The Commission already has the ability to verify the load data provided by the IOUs in case of a dispute.

The applicable new DA load increase relating to each of the IOU service territories is set forth as follows:

		In gigawatt hours		
Line No.		**SCE**	**PG&E**	**SDG&E**
1	Load Cap Pursuant to SB 695	11,710	9,520	3,562
2	Existing Base Line DA	7,764	5,574	3,100
3	New DA Load Allowance (Line 1 less Line 2)	3,946	3,946	462

The new load eligible for DA service represents a relatively small portion of each of the utilities' portfolios, involving less than 10 million megawatt hours (MWh) of annual usage across the entire state. This amount is less than 6% of the entire load served, and is much less than the annual variation in electricity consumption across the state due to the weather and the economy.

The SB 695 cap limits any potential risk associated with reopening of DA by eliminating uncertainty associated with load migration. The adopted phase-in schedule will provide enough lead time for the IOUs to account for small shifts in load and thereby avoid unwarranted cost shifting and stranded load.

3.1. Discussion

We conclude that the utilities reported load figures reasonably comply with the criteria set forth in SB 695. We adopt those figures for use in this decision in implementing SB 695 caps. The SCE figures require some explanation.

In its opening comments, SCE set forth the overall DA cap under SB 695 and the baseline amount for SCE's service area,[7] as follows:

- Based on kWh sales data maintained in SCE's billing system, the maximum recorded sales to SCE distribution customers by all other providers for any sequential 12-month period was 11,710 GWh from July 2003 through June 2004.
- SCE's current level of DA in its service territory, expressed as the annual load of those customers taking DA as of November 30, 2009, is 7,627 GWh.

Subsequent to the filing of these comments, SCE subsequently amended its initial calculation of DA baseline amounts to recognize the effects of the MWh set-aside granted for the City of Cerritos (Cerritos). The Commission issued D.10-01-012 determining the rights of Cerritos under AB 80. As a result of this decision, SCE revised its reported baseline of current DA load in its service territory to include the set-aside of MWh for Cerritos, which the Commission found to be required by AB 80.

In D.10-01-012, the Commission concluded that AB 80 authorizes Cerritos to enter into direct transactions with any retail end-use customer in its jurisdiction on an opt-in basis up to Cerritos' generation entitlement share of the

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[7] *See* SCE Opening Comments at 7, citing its December 3 and December 29, 2009 data response filed in this proceeding.

Magnolia Power Plant (MPP) output.[8] D.10-01-012 clarified that AB 80 does not require Cerritos to provide *opt-out* service, as is provided by community choice aggregators.[9]

Cerritos currently serves about 13.02 megawatts (MW) of opt-in, non-residential load. However, D.10-10-012 makes clear that Cerritos has a right "to sell all of its entitlement share [of MPP's output] on a retail basis."[10] SCE has calculated Cerritos' share of the annual MPP output as 137.5 gigawatt hours (GWh).[11] Therefore, under D.10-01-012, Cerritos is entitled to serve 137.5 GWh of annual, opt-in load.

D.10-01-012 affects the implementation of SB 695 in the following manner:

- Because Cerritos is not a community choice aggregator, it is considered to be an "other provider" within Section 365.1 of the Public Utilities Code. Therefore, the maximum allowable total kWh annual limit in SB 695 should include customers' acquisition of electrical service from Cerritos.
- Unlike all other providers, Cerritos has been found by the Commission to have a right to sell a certain annual amount of energy via direct transactions to retail end-use customers. This necessitates a permanent "set-aside" for Cerritos under SB 695's overall annual kWh cap, thereby increasing the baseline for SCE's service area.

Accordingly, SCE's current level of DA in its service territory, expressed as the annual load of those customers taking DA as of November 30, 2009, *plus*

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[8] *See generally* D.10-01-012, issued January 21, 2010 in A.09-06-008.

[9] *See id.* at 7-8.

[10] *See* D.10-01-012 at 13.

[11] SCE must file an advice letter to set forth Cerritos' share of the MPP output; therefore SCE's calculation is subject to Commission review for compliance with D.10-01-012.

Cerritos' set-aside of 137.5 GWh under D.10-01-012, is adjusted to 7,764.5 GWh. Cerritos' set-aside will not be available for other providers, even if Cerritos does not sell all 137.5 GWh annually to retail end-use customers in SCE's service area.

4. Phase-In Schedule for Increased Cap

4.1. Parties' Positions

The statute requires that the new DA load growth be phased in over a period of not less than three years and not more than five years.[12] Certain parties express support for a three-year phase-in period, arguing that it offers the most efficient and consumer-friendly approach. PG&E, SDG&E, and various parties representing DA interests believe that a three-year phase-in period will accommodate IOU long-term procurement and resource planning needs. All parties generally agree to defining the duration of each phase-in interval as a calendar year, with the exception of the first year, which would cover only the period from the effective date of this decision through December 2010.

PG&E recommends an annualized usage cap increment of 1,500 GWh/year for each year of the phase-in period. If additional DA load is fully subscribed each year, the phase-in would then be completed in three years. If, however, DA demand varied from year to year, the cap would guard against the potential for extreme load changes from any one year to the next, but could extend the phase-in period up to the five years allowed under the statute.

PG&E states that establishing an annual cap will address the potential procurement issues that could otherwise occur if there were extreme differences in demand for new DA from one year to the next during the phase-in period.

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[12] Pub. Util. Code § 365.1(b).

To provide additional flexibility, however, PG&E expresses a willingness to employ a "soft" cap each year of the phase-in period to allow a customer whose load may slightly exceed the annual cap to proceed with enrollment onto DA service. PG&E believes that an additional 5% over the annual cap is reasonable.

A group of parties (Joint Parties) entered into discussions after the initial round of comments were filed, and agreed upon a joint proposal.[13] In entering into the joint proposal, some of the Joint Parties modified their previous position set forth in opening comments.

The Joint Parties propose a four-year phase-in period, structured to allow up 50% of the room available under the cap in the first year, up to 70% in the second year, up to 90% in the third year, and up to 100% in the fourth year of the phase-in period. The Joint Parties argue that a four-year phase-in with a larger increment available initially, will accommodate a larger influx while avoiding the need for customers to rush to get in under the cap at the outset if they are not ready to do so.

SCE argues that allowing excessive DA enrollment in the first year could detrimentally impact the administration and processing of Direct Access Service Requests (DASRs) as well as the utility's ability to meet procurement requirements to accommodate changes in load.

TURN joins with the other Joint Parties in proposing a four-year phase-in period. Alternatively, assuming that the Commission is convinced that a rush of

[13] Parties sponsoring the joint proposal were TURN, SCE, CACES/AReM, the California State Universities, DACC, Silicon Valley Leadership Group, and School Project for Utility Rate Reduction.

new customers could reasonably be expected at the initial reopening, TURN believes that a three-year phase-in might be warranted. TURN supports the establishment of annual GWh caps in advance, independent of the amount of actual load migration in prior years of the transition.

TURN believes that monitoring must continue beyond the initial phase-in period to keep up with changes in DA load. The level of the DA cap will remain in effect beyond the end of the phase-in period unless or until changed by future legislation. The IOUs will need to know on an ongoing basis whether or not they can accept new DASRs, and ESPs will need to know whether they is any further room available for marketing purposes.

CLECA and California Manufacturers & Technology Association (CMTA) jointly argue that the Commission should phase in the reopening over the full five-year period, rather than a three-year period. DRA agrees with CLECA and CMTA. CLECA believes that three-year phase-in period, with as much as 75% of the available headroom made available to new customers during a 60-day open-enrollment period, will create a "gold rush" mentality, resulting in a variety of negative consequences. For example, CLECA expresses concern that customers would be motivated to act quickly, perhaps precipitously, to exercise their option to acquire DA, without having adequate time to analyze and absorb the many factors that should be weighed in such a decision. CLECA also argues that a gold rush environment would tend to increase transactional costs, particularly for the IOUs' processing of new requests to switch to DA.

CLECA notes that if a DA-eligible customer returned to bundled service in July 2009, that customer could return to DA service immediately during the initial enrollment period after the April 2010 reopening of DA, but if the customer did not make the election during the initial enrollment period, the customer would have to wait more than two years after that reopening to make its return to DA service. CLECA expresses concern that an existing DA-eligible customer could find that it had lost entirely the ability to return to DA if the Commission were to permit a rapid phase-in of the new DA service for non-DA-eligible customers.

CLECA also proposes that the Commission should permit additions per year of no more than 20% of the total allowed increment in new DA. CLECA argues that this slower pace of phase-in would reduce transitional and generational planning issues.

CEC suggests a three-year phase-in schedule, with 75% of total load permitted in the first year, and the remaining 25% spread equally over the following two years. In this manner, subsequent adjustments can be made based on the first year's experience.

4.2. Discussion

We have considered the range of proposals as to the duration and pacing of phase-in, ranging from three years to five years. We conclude that a three year period is too short, and could cause an excessive surge in demand for new DA, resulting in potential negative consequences, as noted by CLECA and DRA. We likewise conclude that a five-year phase-in period is too long, and would unduly prolong the phase-in of new DA. We shall therefore adopt a four-year phase-in period. Our adopted phase-in generally incorporates the Joint Parties' proposed four-year phase-period, but we shall apply a more gradual pace in annual DA limits compared with the Joint Parties' proposed first-year limit of up to 50%. A front-loading of 50% in the first year could create a surge in demand for DA concentrated in the open enrollment window between mid April and June 30, 2010. This surge could be amplified especially since Year 1 will be truncated to nine months with an April 11 start date. Joint Parties' proposal for a cumulative DA load cap of 70% by the second year only leaves 20% in the second year if enrollment reaches 50% in the first year. As a result, customers could feel pressured to rush to sign up before the June 30th deadline.[14] The truncated first year could create an undue burden on the program's first year.[15]

We shall therefore adopt annual DA caps of up to 35% in the first year, up to 70% in the second year, up to 90% in the third year, and up to 100% in the fourth year. Limiting the adopted limits in this manner reduces the burden on potential DA customers to sign up in the first year, and correspondingly increases the load available for new DA customers in the second year. Moderating the first year's cap to 35% will help prevent the potential for customers to become aggrieved by being rushed into signing up for direct access without adequate time to consider all of the factors involved.

We conclude that the four-year phase-in period, with the related annual limits on new enrollments, strikes a reasonable balance, providing for an orderly implementation schedule that is manageable by the IOUs while still satisfying the requirements of SB 695 in a timely manner. We find that adopted phase-in schedule reasonably addresses the relevant concerns that must be balanced in crafting the appropriate pacing of the phase-in process. The first year of the phase-in covers the partial period beginning on the effective date of this decision,

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[14] Appendix 2 at 4, 8.a., "Customers may submit 6-month advance NOIs starting July 1, 2010 to switch to DA in 2011."

[15] Reply Comments of The Division of Ratepayer Advocates on Assigned Commissioner's Ruling Regarding Issues Associated With Senate Bill 695 Relating To Direct Access Transactions (February 1, 2010) at 5.

and continuing through the end of the 2010 calendar year. Each subsequent phase-in period shall cover a full 12-month calendar year.

If any annual allocation of DA allotments under the cap is not fully subscribed in any one year, the unused portion shall be rolled over to the subsequent years. Each individual year's DA limit shall stand alone, and not be dependent on the amount of actual migration in prior years of the phase-in.

All DA-eligible customers will be free to switch to DA at any time, subject to the applicable switching rules, as long as room exists under the overall cap. Monitoring shall continue beyond the phase-in period because the cap on DA will remain in effect and must be enforced unless or until changed by future legislation.

5. Process to Implement New DA Enrollments

5.1. Parties' Positions

The Joint Parties presented a detailed proposal for a utility enrollment process during the phase-in period that is set forth in Appendix 2 of this decision. SCE joined in the Joint Party proposal. The Joint Party proposal calls for an initial open enrollment period going through June 30, 2010, with a temporary one-time waiver of the 6-month advance notice requirement and one-time waiver of the bundled service commitment under Rule 22.1. The details of the proposal for the receipt, review, and approval of customer requests to switch to DA service under SB 695 are set forth in detail in Appendix 2 of this decision.

PG&E presented its own separate proposal for enrollments. Every customer would be required to submit a notice to their IOU that they want to switch to DA service. Upon acceptance of a customer notice to switch to DA service, PG&E will provide instructions for DASR submittal in a confirmation letter. If a valid DASR is submitted during the DASR window indicated in the customer confirmation letter, the customer will switch on the date indicated. If no DASR is received by the close of the DASR window, the account will be placed on Transitional Bundled Service or "safe harbor" status. That means it will be billed on the Transitional Bundled Commodity Cost (TBCC) rates and given an additional 60 days in which to submit a valid DASR. If no DASR is submitted during this additional 60-day period, the customer notice is cancelled, the account continues on the TBCC rates for an additional six months, and then the account is committed to bundled portfolio service for a three-year period. In addition to following the existing switching rules, this would also discourage speculative submittals of customer notices, and allow customers who are serious about switching to DA service the ability to do so without the impediment of over-subscription of available load under the cap by more speculative participants.

SDG&E also presented its own proposal (as Attachment A of its February 1, 2010 Reply Comments) as to the processing protocols for enrolling customers under the provisions of the SB 695 cap. SDG&E's proposed approach is similar to the approaches proposed by SCE and CACES/AReM. SDG&E's process calls for the customer to submit a notice of intent (NOI) within the designated open enrollment period, subject to a daily batching process. SDG&E would apply a "soft cap," not to exceed 10% of the annual cap, in evaluating whether a request was to be approved. Customers would be notified within 20 calendar days as to whether their NOI was accepted. DASRs would be processed in accordance with SDG&E's Rule 25.

DACC points to the customer application and tracking process adopted for the California Solar Initiative as an example to follow for administering the DA allocations. As proposed by DACC, a customer interested in transferring load to

DA service would submit a "Customer-Originated Direct Access Service Request" (CODASR) to its local IOU(s). Each CODASR would correspond to a customer utility service identification (ID) account number, covering the entire load served through that ID, as measured by the preceding 12-month billing period. Customers submitting completed CODASRs would be allocated priority rights to the available DA capacity on a first-come, first-served basis. The customer would have 30 calendar days to complete negotiations with a supplier, and for the supplier to submit a traditional DASR for the customer. If no DASR was submitted on behalf of a customer within the 30-day period, the rights to the available DA capacity previously allocated to that customer would be allocated to the customer with the next lower priority of rights.

5.2. Discussion

We shall adopt an enrollment process for customers to sign up for direct access subject to the revised SB 695 limits under the provisions adopted in this decision, as set forth in Appendix 2 of this decision.

The adopted process incorporates the four-year phase-in discussed above. It also incorporates a uniform treatment of all qualifying customers, without a separate set-aside or preferential treatment of existing DA-eligible customers. We address this issue further in Section 6. We also adopt a two-day window for customers to correct NOI deficiencies. The two-day limit will facilitate timely processing of daily NOI batches.

In comments to the proposed decision, the Joint Parties argued that each IOU should be authorized to maintain a limited wait-list during the OEW to back-fill any room under the first-year allocation occupied by NOIs that are submitted but ultimately voided for failure to submit a DASR or correct a deficiency. We find this proposal to be reasonable, and shall incorporate a wait-list process into the adopted procedure set forth in Appendix 2.

The utilities shall begin placing submitted NOIs on an OEW wait-list on a first-come, first-served basis when or if the Year 1 allocation becomes fully subscribed during the OEW. There will be no wait-list after the OEW closes. The OEW shall be filled up to 25% of the Year 1 allocation. The IOU shall notify the customer that they are on the wait-list within 20 days after submission of the customer's NOI. Notifications to customers that they are eligible to come off the wait-list (on a first-come, first-served basis) shall be made by email within one business day of the utility's determination that space is available under the Year 1 allocation. All such notices shall be made no later than June 29, 2010, the last day of the OEW. The submission and processing schedule, as set forth in Appendix 2 shall apply.

Each IOU shall be required to indicate on its public website whether notices of intent to switch to DA service are being accepted, and to update this information regularly. This information should be sufficient to inform customers and ESPs whether there is room under the annual limits during the phase-in period or the overall cap after the phase-in. Each IOU shall notify all DA-eligible customers of their opportunity to obtain generation service from another provider of the Effective Date. Each IOU shall provide a link to the new DA provisions on their respective web sites and shall also provide additional notification via bill inserts and onserts. ESPs shall notify their customers of their procurement-related obligations.

6. Waiver of DA Switching and Notice Rules and Subsequent Rights to Acquire DA

6.1. Parties' Positions

Under current rules,[16] former DA customers currently receiving bundled utility service must provide six-months' notice in order to leave bundled utility service. The same six-month notice requirement applies for customers that switch back to DA. Also, a DA customer who returns to bundled service must commit to stay for at least a three-year period.

PG&E proposes that the current three-year minimum bundled service commitment for customers now on bundled portfolio service be waived for an initial implementation period, starting on the date established by the Commission and extending for 60 days. Absent such a waiver, existing Bundled Portfolio Service (BPS) customers may be precluded from switching to DA service if the maximum load cap is reached before these customers complete their three-year commitment period.

In addition to waiving the three-year commitment period, PG&E would support giving BPS customers a higher priority to return to DA compared with "new prospective" DA customers, limited to the initial implementation period.

SCE does not support providing a preference to existing DA-eligible load, but proposes that all DA-eligible customers be provided an equal opportunity to enroll in DA if they so choose. SCE supports a temporary, one-time waiver of the six-month advance notice requirement during the open enrollment period. SCE also supports a one-time waiver to all DA-eligible customers under current BPS commitments, so that these customers can take DA service at any time upon

[16] *See* D.03-05-034 and D.03-06-035.

notice of intent (during the open enrollment) or a six-month advance notice (after the open enrollment), assuming that there is sufficient room under the annual limits or overall cap. SCE proposes that the three-year BPS commitment period continue to apply anytime that a DA customer returns to BPS.

After the open enrollment period ends, SCE proposes that the DA switching rules apply equally to all DA-eligible customers, including bundled service customers wishing to switch to DA for the first time, unless and until the Commission reviews and modifies these rules in a subsequent phase of the proceeding.

SCE proposes to establish a wait list and to enroll customers on DA service on a first-come, first served basis, as room becomes available under the annual limits or overall cap.

TURN argues that there is no compelling need for granting any special preference for load that is DA-eligible under the current rules. TURN believes that there is minimal risk that load that is DA-eligible under the current rules, and subject to the three-year minimum stay on bundled service will be "squeezed out" by new DA load. The highest annual figure reported by any of the IOUs for potential DA-eligible bundled load returning to DA service is 475 GWh for PG&E during the period from April 2010 through April 2011. That amount is only about 50% of the quantity proposed by TURN to be made available in the first year of the phase-in period. The other utilities and the other years for PG&E show an even smaller percentage.

TURN argues that no special set-aside preference should be granted to existing customers who are DA-eligible under current rules other than to allow them to terminate their three-year minimum commitment on bundled service in April of the year which the commitment would otherwise expire. In this manner, these customers could request DA service as soon as the next phase-in step occurs. TURN believes that such provision would be sufficient to prevent any DA-eligible customer from being "stranded" on bundled service because of the new total GWh cap on DA. TURN argues that updates on DA load should be posted at least monthly, and perhaps more frequently in a month when a utility's DA load is approaching the cap level.

TURN does not object to a temporary suspension of the six-month notice requirement for customers switching from bundled service to DA, but only during the first year of the phase-in period. TURN does not believe that a continued waiver period beyond the first year is necessary, because customers will be in a better position to provide notice in subsequent years of the phase-in period.

TURN proposes that any and all customers returning to bundled service from DA should remain subject to at least a six-month notice period during which time they would be subject to the Transitional Bundled Service (TBS) rate if they return to bundled service prematurely. TURN believes that at least a one-year notice should be required in order for the returning customer to avoid becoming subject to the TBS rate. If a customer returns to the IOU with less than a one-year notice, the IOU would have to obtain additional resource adequacy (RA) resources outside of the normal procurement cycle, potentially resulting in higher costs for the IOU and bundled customers.

The Joint Parties argue that all customer eligible to switch to DA under SB 695 should be provided an equal opportunity to enroll in DA as of the effective date if they so choose.

6.2. Discussion

We shall grant all DA-eligible customers currently under BPS commitments a one-time waiver of their BPS commitments to allow them an equal opportunity to enroll in DA as of the Effective Date of this decision. A temporary one-time waiver of the six-month advance notice requirement shall also be granted to all DA-eligible customers to allow them an equal opportunity to enroll in DA during the initial open enrollment window, as described in Appendix 2 hereto. The waivers shall apply only during the initial open enrollment window. The long-term applicability of the three-year minimum BPS commitment and six-month advance notice requirements shall be addressed in a subsequent phase of this proceeding. We shall not grant a special preference or set-aside of load to existing DA-eligible customers. Instead, an equal opportunity to enroll in DA shall apply to all eligible customers.

SCE suggested in its comments that residential customers who have taken DA service in the past, but now take utility bundled service (considered as "DA-eligible" under the Commission's rules in effect prior to the enactment of SB 695), would be permitted to switch back to DA service during the phased reopening period. TURN disagrees, however, arguing that SCE's interpretation is inconsistent with SB 695.

SB 695 repealed the prior statutory provisions regarding the suspension of DA which had been in effect since 2001, and replaced those provisions with a new statute, Public Utilities Code Section 365.1. The new statute provides, in relevant part, as follows:

> 365.1. (a) Except as expressly authorized by this section, and **subject to the limitations in subdivisions (b) and (c)**, the right of retail end-use customers pursuant to this chapter to acquire service

> from other providers is **suspended** until the Legislature, by statute, lifts the suspension or otherwise authorizes direct transactions. . . .
>
> b) The commission shall allow individual retail **nonresidential** end-use customers to acquire electric service from other providers in each electrical corporation's distribution service territory, up to a maximum allowable total kilowatt hours annual limit. . . . . (Emphasis added.)

TURN argues that Section 365.1(a) suspends the right of retail end-use customers provided elsewhere in statute (in the AB 1890 revisions to the Public Utilities Code) to acquire service from other providers ***except*** as authorized therein ***and subject to the limitations*** in subdivisions (b) and (c). Among those limitations is the provision that allows only ***nonresidential*** end-use customers to acquire DA service, up to a maximum annual kWh limit.

We agree with TURN's interpretation. Nothing in the statutory language indicates that any residential customer not *already* taking DA service would be permitted to take service from another provider under the annual kWh limit during the period of the suspension. Accordingly, we affirm that the right to acquire new DA pursuant to SB 695 excludes residential customers who are not already taking DA service. However, an existing DA-eligible residential customer on bundled service that has already given its six-month notice to return to DA prior to the effective date of this decision would still retain the right to return.

7. Meter Installation Waiver

7.1. Parties' Positions

Under current rules, any customer with a peak load that is greater than 50 kilowatts (kW) is required to install an approved interval meter. Interval meters allow customers better access and control to their load consumption, and are a step toward a smarter, more efficient electric grid.

CACES believes that the requirement for DA customers to install interval meters in order to receive DA service should be modified to allow a customer to choose whether or not they want to install such a meter in advance of the "Advanced Meter Initiative" deployment. CACES argues that such DA customers should not be required to pay for an interval meter that will soon be replaced by an Advanced Metering Infrastructure (AMI) meter, particularly because they are already paying for the AMI deployment.

All customers with load greater than 200 kW already have interval meters. CACES argues that any commercial/ industrial customers whose peak load is between 50 kW and 200 kW should have the choice of whether to install an interval meter.

SCE proposes that service accounts with demand between 50 kW and 199 kW be granted a temporary waiver from the DA interval meter requirement pending the scheduled installation of an Edison SmartConnect meter, unless the meter is required by the ESP. SCE proposes that if the customer's ESP requires an interval meter, the ESP would be billed for the cost of such meter.

SCE argues that a waiver should not apply to customers with service accounts having a demand of 200 kW or greater since under SCE's tariffs, such accounts are required to have interval metering.

7.2. Discussion

A temporary waiver of each utility's DA interval meter installation requirement applicable to service accounts with demand between 50 kW and 199 kW shall be granted, pending the scheduled installation of an AMI smart meter by the utility, unless an interval meter is specifically requested by the customer's ESP. If the customer's ESP requests an interval meter, the ESP will be billed for the cost of such meter. If a DASR is submitted for a customer who does not have an interval meter in place, and an AMI smart meter is not installed before the next meter read cycle, load profiles will be used for settlement purposes, trued up by actual meter reads, as is done for customers with loads less than 50 kW, until an AMI smart meter is installed. All customers with service accounts having a demand of 200 kW or greater are required to have interval metering. Therefore, a waiver shall not apply to these accounts.

Utility Tariff Rule 22 requires that service accounts with demands greater than 50 kW have interval meters prior to being placed on DA service.[17] Therefore, a revision to the Utility Tariff Rule 22 will be necessary to authorize this waiver. The utilities shall incorporate this revision in their advice letter filings implementing the requirements of this order.

8. Compliance with Procurement and Resource Planning Rules

SB 695 requires the Commission to ensure that other providers of electricity in California are subject to the same procurement-related requirements that apply to the IOUs, including resource adequacy requirements, renewables portfolio standards, and greenhouse gas emission reductions.

Pursuant to SB 695, once the Commission has authorized additional DA transactions, it is required to ensure that other providers are subject to the same requirements that apply to the three largest California electric utilities under:

1. Commission-adopted programs to implement the resource adequacy provisions of Public Utilities Code Section 380;

[17] *See* Utility Tariff Rule 22, Section A.2.

2. Renewable portfolio standards of the Public Utilities Code, Article 16; and
3. Electricity sector requirements adopted by the California Air Resources Board pursuant to the California Global Warming Solutions Act of 2006.

8.1. Parties' Positions

Various parties affirm the importance of enforcing uniform procurement and resource planning rules on all load serving entities (LSEs). SCE, in its comments, identified a number of issues that remain to be addressed by the Commission to ensure that these requirements are imposed in a uniform manner among all LSEs. As noted in the Assigned Commissioner's Ruling dated November 18, 2009, specific additional procurement-related requirements will be considered in the appropriate proceedings. SCE asks that in the final decision in this sub-phase we order the immediate opening of a separate sub-phase here, or in other existing proceedings, to address any and all remaining issues regarding procurement-related obligations of ESPs under SB 695.

TURN identifies the potential problem with the allocation of RA resources in this regard. Under current rules, a customer's new ESP is not required to obtain its proportionate share of Local RA resources until the 2011 RA compliance year, because Local RA is subject to only an annual compliance obligation, with no monthly true-up. At the same time, the IOU that loses the load will have no market for the Local RA resources that it had previously procured to serve that load. TURN argues that while a longer-term solution to this problem may be developed in Rulemaking (R.) 09-10-032, the new RA OIR, that proceeding cannot be expected to produce a resolution of the issue by April 11, 2010. As a result, TURN expresses concern that bundled service customers may be left with a disproportionate share of Local RA obligations and costs for the remainder of 2010, including the critical summer peak period when RA is particularly valuable and costly.

TURN initially proposed as an interim solution – pending longer-term resolution of the issue in R.09-10-032 – that ESPs obtaining additional load as a result of the DA reopening in April 2010 be required to purchase the proportional amount of Local RA capacity from the host IOU at an RA "waiver trigger" price of $40 per kW-year, pro rated as appropriate for the remainder of the current year. TURN argued that this interim measure will help to prevent inappropriate gaming and avoid creating a perverse incentive for customers to switch providers simply to avoid their fair share of Local RA costs.

TURN argues that new ESPs entering the market should not be treated any differently from existing ESPs or IOUs with respect to RPS requirements. TURN notes that the rules require all LSEs to procure 20% of their energy from eligible renewable projects by 2010, subject to the applicable flexible compliance rules.

PG&E also recommends that resolution is needed on how DA customers and ESPs could make IOUs whole for the local RA that has already been procured in 2010, thereby effectuating the transfer of local RA from the IOUs to ESPs at a price certain. PG&E believes that TURN's January 11, 2010 filing in R.09-10-012 is simple and can be adapted for this purpose. PG&E states that this approach would not have precedence on the long-term proceeding under R.09-10-012, or the RA proceeding R. 09-10-032, but would only apply for 2010.

A proposal for an interim solution to Local RA obligations was further developed in the comments of the Joint Parties. As noted by the Joint Parties, the reopening of DA in April 2010 comes in the middle of the RA program compliance year, which is administered on a calendar year basis. While system RA obligations are adjusted on a monthly basis to reflect migration of customers between LSEs under current procedures, no similar adjustment exists for Local RA. Proposals to adopt a formal Local RA load migration adjustment are under consideration in R.09-10-032 for compliance year 2011. In view of the increase in load migration that may occur as early as April 2010, however, a more immediate temporary solution to deal with this issue is needed. This interim solution is described in Appendix 3 hereto.

The proposed temporary solution, as set forth in the Joint Parties' comments, provides a means of establishing a value for a "Customer Local RA Obligation" when a customer seeks to migrate between LSEs after the effective date of DA reopening. This value will be based upon the customers' actual 2009 Coincident Peak Demand multiplied by a "Local-to-Peak Ratio" that will be calculated for each IOU service territory, as set forth in Appendix 3. The resulting figure (expressed in MW) will constitute the Local RA Obligation of that customer. The LSE gaining the additional load will have the option to obtain an allocation of RA "credits" from the LSE losing the load without the need for an actual sale of physical capacity to occur between the two LSEs. The LSE gaining the load would make a payment to the LSE losing the load equal to the customer's Local RA Obligation multiplied by a default transfer price of $24 per kW-year. This payment would be deemed to satisfy the acquiring LSE's Local RA Obligation for the remainder of the 2010 compliance year.

8.2. Discussion

We recognize the need for timely action on resolving any remaining issues relating to procurement-related obligations of ESPs under SB 695. We conclude, however, that as a general matter, the adoption of a specific timetable and the scope of the relevant issues is best addressed in the separate proceedings where the relevant specialized expertise already exists. As an exception to this general approach, however, we conclude that the one specific issue relating to RA obligations, as discussed in the Joint Parties' comments, requires an interim resolution in this proceeding. We agree that the Joint Proposal offers a reasonable short-term solution to deal with the issue of Local RA Obligations and we adopt it on that basis. The proposed temporary solution is set forth in Appendix 3 of this decision, based upon the Joint Proposal. This interim solution is adopted for implementation as part of the initial phase-in of new DA load in order to allow DA transactions to proceed in a timely manner while accounting for the impacts on RA obligations.

The adopted solution will provide an expedient means of establishing a value for a Customer Local RA Obligation for use when a customer transfers from one LSE to another during the initial DA open enrollment period. The temporary solution will avoid the potential for cost shifting or undue competitive advantage associated with the Local RA Obligation. After 2010, this temporary solution would be superseded as a result of whatever solution (if any) is adopted in R.09-10-032 for the 2010 compliance year.

This temporary solution shall explicitly apply only for calendar year 2010, and shall either continue or be replaced as a result of whatever solution (if any) is adopted in R.09-01-032 for the 2011 RA compliance year. To facilitate a smoother synchronization between the phased increase in DA load and the annual RA schedule, the next step in the DA phase-in schedule would occur on January 1, 2011, rather than on April 11, 2011. The use of the January date would allow LSEs' year-ahead Local RA showings for 2011 to reflect any load migration that is expected to occur at the start of the next DA reopening phase-in. The ESPs will remain subject to the previously adopted RA showing process which starts in July 2010 for 2011 showings.

We make certain revisions to Appendix 3 based upon comments on the proposed decision. For example, we revise the previous references in the proposed decision to Local RA obligations being "aggregated by NP-26 and SP-26," and instead specify the local areas for which LSEs must procure Local RA. We also incorporate Joint Parties' proposed modifications to the formulas for calculating the Local-to-Peak ratio and the Customer Local RA obligation, as set forth in Appendix 3.

The Joint Parties propose that all LSEs that intend to serve load during 2011 refile load forecasts for the 2011 RA compliance year on July 15, 2010

We shall adopt the due date of May 26, 2010 (instead of July 15, 2010), for LSEs to provide Energy Division with revised load forecasts for the 2011 RA compliance year. Based on the timing for the IOUs to respond to NOIs, a suitable compromise is to have forecasts due from LSEs on May 26, 2010. This will be the only forecast due for 2011 year-ahead compliance.

9. Categorization and Assignment of Proceeding

This proceeding is categorized as Ratesetting. The assigned Commissioner is Michael R. Peevey and the assigned ALJ is Thomas R. Pulsifer.

10. Comments on Proposed Decision

The proposed decision of ALJ Pulsifer 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 March 1, 2010, and reply comments were filed on March 8, 2010. The proposed decision was also mailed to the service lists of R.08-01-025 and R.09-10-032 so that all affected LSEs could comment on the proposed decision. We have incorporated parties' comments, as appropriate, in finalizing this decision.

Findings of Fact

1. On October 11, 2009, SB 695 was signed into law as an urgency statute, adding Section 365.1 (b) to the Public Utilities Code.

2. Public Utilities Code Section 365.1(b) requires the Commission to allow individual retail nonresidential end-use customers to acquire electric service from other providers in each electrical corporation's distribution service territory, up to a maximum allowable total annual limit.

3. The amounts of DA load as set forth in Appendix 1 of this decision constitute the incremental amount of transactions that are allowed in conformance with implementation of Public Utilities Code Section 365.1(b).

4. The statute allows for a phase-in period for new DA of not less than three years and not more than five years, subject to Commission determination.

5. A four-year phase-in period with annual caps as set forth in Appendix 2 will reasonably accommodate the utilities' long-term procurement and resource planning needs, while providing for timely implementation of new DA load consistent with the provisions of SB 695.

6. Under current rules, former DA customers receiving bundled utility service must provide six-months' notice in order to leave bundled utility service. The six-month notice requirement applies for customers that switch back to DA. A DA customer who returns to bundled service must commit to stay for at least a three-year period.

7. Under current rules, any customer with a peak load that is greater than 50 kW is required to install an approved interval meter. Interval meters allow customers better access and control to their load consumption, and are a step toward a smarter, more efficient electric grid.

8. Rule 22 requires that service accounts with demands greater than 50 kW have interval meters prior to being placed on DA service.

9. SB 695 requires that other providers of electricity in California are to be subject to the same procurement-related requirements that apply to the IOUs, including resource adequacy requirements, renewable portfolio standards, and greenhouse gas emission reductions.

10. The interim measures set forth in Appendix 3 for the treatment of Local RA obligations during the enrollment period for new DA will provide a reasonable way to satisfy an LSE's RA obligations in connection with customer migration pursuant to SB 695, subject to any further disposition in R.09-10-032.

11. The enrollment procedures for new Direct Access Load as set forth in Appendix 2 of this decision provides for an orderly process that will be manageable by the utilities while providing for timely processing of new enrollments.

12. The Proposed Decision (PD) was served on parties in R.08-01-025 and R.09-10-032 so that all affected Load Serving Entities could comment on the PD.

Conclusions of Law

1. The Commission is required by the provisions of Public Utilities Code Section 365.1(b) to allow individual retail non-residential end-use customers to acquire electric service from other providers in each electrical corporation's distribution service territory, up to a maximum allowable total annual limit.

2. The authorizations for increased DA transactions, as set forth below in the ordering paragraphs of this decision, reasonably satisfy the requirements of Section 365.1(b) for increased limits in DA transactions.

3. The investor-owned utilities should proceed with implementation of the processing of new DA service requests in accordance with the revised limits adopted below.

4. A temporary one-time waiver of the current three-year minimum bundled service commitment for customers now on BPS customers should be granted covering the initial open enrollment period, starting on the effective date of this decision and extending through June 30, 2010.

5. Any commercial/industrial customers whose peak load is between 50 kW and 200 kW should have the choice of whether to install an interval meter.

6. The procedures for enrollment of new DA load pursuant to SB 695, as set forth in Appendix 2 of this decision, are reasonable and should be adopted.

7. The procedures for the treatment of Local Resource Adequacy Obligations pursuant to SB 695, as set forth in Appendix 3 of this decision are reasonable and should be adopted.

8. The next phase of this proceeding should expeditiously address the remaining issues to be resolved relating to the phase-in of additional limits on direct access transactions.

9. The provisions for new enrollments of DA customers under SB 695 should be based upon a first-come, first-served principle, without special set-asides for DA-eligible customers who have exercised the right to take DA previously.

10. In order to establish an orderly process for enrolling new DA customers pursuant to SB 695, a Notice of Intent (NOI) to subscribe to DA should be submitted by customers. The NOI should be subject to utility review and notification of space availability to the customer and the ESP in accordance with the procedures set forth in Appendix 2 of this decision.

11. SB 695 contains no language granting any preference or special rights to DA-eligible customers who have exercised the right to take DA previously, and there is no basis for the Commission to impose special preferential treatment for such DA-eligible customers in implementing SB 695.

12. For purposes of determining if the authorized cap has been reached in relation to the total requests for new DA service, a daily NOI batching process, as proposed by the Joint Parties, provides for a more streamlined implementation.

13. The right to acquire new DA pursuant to SB 695 excludes residential customers who are not already taking DA service o otherwise eligible per D.05-03-034.

ORDER

IT IS ORDERED that:

1. Revised limits are hereby adopted in the cap on direct access transactions within the service territories of each of California's three major investor-owned utilities, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, as set forth in Appendix 1 of this decision. The authorized increases in direct access transactions shall be incorporated into the utilities' tariffs pursuant to Ordering Paragraph 8. Adjustments to each utility's baseline amount of direct access load as set forth in Appendix 1 shall be based on the same method used by the utilities to calculate direct access load in their Direct Access Implementation Activities Reports submitted to the Commission on a monthly basis. The Energy Division is authorized to post each utility's monthly baseline amount of direct access load,

as reported in their Direct Access Implementation Activities Reports, on the Commission's public website.

2. The increased limits on direct access transactions set forth in Appendix 1 hereof shall be phased in over a four-year period beginning on the effective date of April 11, 2010, in accordance with the enrollment procedures set forth in Appendix 2.

3. A one-time waiver of the current three-year minimum bundled service commitment for customers now on bundled portfolio service is hereby granted for any bundled portfolio service commitments in existence as of April 11, 2010, the direct access reopening effective date. This one-time waiver will effectively eliminate those bundled portfolio service commitments in existence on the Effective Date of the direct access reopening, even if those customers do not elect to take direct access service during the Open Enrollment Window, to allow these customers to elect Direct Access service at any time with the required 6-month advance notice, assuming there is room under the annual limits or overall cap. The three-year bundled portfolio service commitment period will continue to apply anytime a Direct Access customer returns to bundled portfolio service after the Effective Date of the direct access reopening.

4. The increased authorizations in the level of direct access transactions as set forth in Appendix 1 of this decision shall take effect beginning April 11, 2010, and continue for four calendar years, with annual limits as set forth in Appendix 2.

5. The procedures for enrollment of new direct access load pursuant to SB 695, as set forth in Appendix 2 of this decision, are hereby adopted. The IOUs shall file advice letters within 20 days of the issuance of this decision proposing modifications to their direct access tariffs in compliance with this decision. The

advice filings shall be effective upon filing, and any modifications subsequently requested by the Energy Division based on its review of the advice filings shall not alter their effectiveness as of their filing dates. The advice letters shall include the form NOI to be used during the Open Enrollment Window authorized in this decision.

6. A temporary waiver is hereby granted of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company's direct access interval meter installation requirement applicable to service accounts with demand between 50 kilowatts (kW) and 199 kW, pending the scheduled installation of an Advanced Metering Infrastructure Smart Meter by the utility, unless an interval meter is specifically required by the customer's electric service provider.

7. A methodology for local Resource Adequacy obligations, based on the Joint Proposal and set forth in Appendix 3, is hereby adopted. The methodology shall be in effect for 2010 only, unless otherwise specified by a future ruling. We delegate authority to the Energy Division to make minor refinements or clarifications to the adopted methodology in the course of implementation.

8. Investor-owned utilities subject to the provisions of this decision are directed to file advice letters to modify their tariff rules in compliance with this decision, due 20 days after the issuance of the decision, and effective upon filing.

9. This proceeding shall remain open to address the remaining implementation issues relating to the increased phase-in of direct access and other pending issues to be addressed in this rulemaking.

This order is effective today.

Dated March 11, 2010, in San Francisco, California

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
TIMOTHY ALAN SIMON
NANCY E. RYAN
Commissioners

Appendix 1

Authorized Increases in Caps on Direct Access Transactions
By Service Territory

Authorized Direct Access Cap Increase (in GWh)
Within Service Territories of the Electric Utilities

	Southern California Edison Company	Pacific Gas and Electric Company	San Diego Gas & Electric Company
Load Cap	11,710	9,520	3,562
Existing Base Line DA	7,764	5,574	3,100
New DA Load Allowance	3,946	3,946	462
Peak Load			

(End of Appendix 1)

APPENDIX 2

Adopted Enrollment Procedures for the Phase-In Period

1. As described more fully below, the phase-in period will begin on April 11, 2010 (the "Effective Date"), and continue for four calendar years, with the annual limits on direct access (DA) load increases over the phase-in period as described in step 2 below, up to the maximum DA cap for each investor-owned utility's ("IOU") service territory (the DA cap). Any kilowatt-hours (kWh) not used in one year will be rolled over to the subsequent years as part of the cumulative increasing annual limits.
2. The annual kWh limits are as follows:
   - Y1 (2010): 35% of the current room available under the DA cap.
   - Y2 (2011): An additional 35% of the current room available under the cap (or70% of the available room under the DA cap).
   - Y3 (2012): An additional 20% of the current room available under the cap (or 90% of the available room under the DA cap).
   - Y4 (2013): An additional 10% of the current room available under the cap (or 100% of the available room under the DA cap).
3. The same switching rules will apply to all customers eligible to switch to DA service under SB 695 ("DA-eligible customers").
4. To facilitate implementation as of the Effective Date, the IOU will notify all DA-eligible customers prior to the Effective Date of the terms and conditions for participation in the partial DA reopening under SB 695. Specifically, the IOU will use a bill insert or onsert[1] to notify all DA-eligible customers as early as March 2010 to visit the IOU's website for details on the partial DA reopening. The website will be updated to ensure accurate information based on the Commission's final decision implementing the DA reopening.
5. To facilitate implementation as of the Effective Date, an Open Enrollment Window ("OEW") will be established as of the Effective Date, during which all DA-eligible customers will be allowed to submit a notice of intent ("NOI")[2] to transfer to DA service.

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[1] A bill onsert is a message imprinted on the customer's bill, as distinguished from a bill insert, which is a separate insertion included in the bill's envelope. The bill onsert may be a more cost-effective way to provide customers notice of the partial DA reopening, because it can be included only on DA-eligible customers' bills, and does not increase the weight of the bills (and thereby should not increase bill mailing costs).

[2] The parties will work together cooperatively in advance of the Open Enrollment Window to develop a uniform NOI in a timely fashion, which shall be filed as part of the IOUs' advice letters implementing changes to their direct access tariffs in compliance with this decision. Customers wishing to authorize

Footnote continued on next page

6. The OEW will begin on the fifth business day after the Effective Date and end ninety (90) calendar days thereafter or on June 30, 2010, whichever comes first. The OEW will occur in Y1 of the phase-in period only.

7. Enrollment during the OEW:

    a. A temporary, one-time waiver of the 6-month advance notice requirement for all DA-eligible customers will be granted so that all DA-eligible customers may begin to enroll in DA service as of the Effective Date if they wish to do so, pursuant to the process described herein.

    b. A one-time waiver of the current Bundled Portfolio Service ("BPS") commitment periods (per Rule 25.1) will be granted so that all DA-eligible customers may begin to enroll in DA service as of the Effective Date if they wish to do so, pursuant to the process described herein.[3]

    c. All LSEs (those that currently serve load and those that do not) will file forecasts of new customers that they expect to gain from via the OEW and other periods for RA compliance years 2010 and 2011 according to the rule set forth by Energy Division for the RA process. Energy Division will issue an amended RA Guide and reporting template for 2010 compliance year as well as an RA Guide and reporting template for 2011 compliance year.

    d. The IOU will begin accepting NOIs up to the Y1 limit as of 9:00 a.m. PST on the fifth business day after the Effective Date. The methods for submitting NOIs will be specified by each utility on its website, provided that all methods shall allow for a time and date stamping to determine precedence. The daily batch process for accepting NOIs during the OEW (described in 7.d below) will allow for up to a 10 percent (10%) threshold above the Y1 limit.

    e. The IOU will process NOIs in daily (12:00 a.m. to 11:59 p.m.) batches. Each daily batch of NOIs will, within 20 days of its receipt, be accepted unless and until the Y1 limit is reached. A daily batch that causes the Y1 limit to be exceeded will nevertheless be accepted provided that such daily batch does not exceed the Y1 limit by more than 10%. Should a daily batch cause the

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their ESP or other third party to submit the NOI on their behalf may do so by providing the IOU with a signed "Authorization to Receive Customer Information or Act on a Customer's Behalf" (CISR) form, indicating that the ESP or other third party is authorized to "Request Rate Changes" for the customer.

[3] The one-time waiver will apply to all non-residential customers under current BPS commitments, even if they do not elect to take DA service during the OEW. After the end of the OEW, these customers may elect DA service at any time with the required 6-month advance notice, assuming there is room under the annual limits or overall cap. However, the 3-year BPS commitment period will continue to apply anytime a DA customer returns to BPS.

Y1 limit to be exceeded by more than 10%, NOIs in that particular daily batch will be accepted on a first-come, first-served basis (based on the date/time stamp of the NOI) up to the Y1 limit plus a threshold of no more than 10%. All other NOIs in that particular daily batch will be rejected.4[4]

f. NOIs submitted during the OEW will be rejected only if the Y1 limit has been reached. Any NOI that is found to have a deficiency (e.g., incorrect service account number) will be accepted on the condition that it is corrected by the customer within two business days after the IOU notifies the customer of such deficiency. NOIs will be void in the event a Direct Access Service Request (DASR) is not timely submitted, as described in 7.h below, or in the event a deficiency in the NOI is not corrected by the customer within two business days.

g. For any NOI accepted during the OEW, the IOU will notify the customer of NOI acceptance within 20 days of NOI receipt, and will instruct the customer to notify its Electric Service Provider (ESP) that a DASR to switch customer's service account(s) to DA service must be submitted to the IOU within 60 calendar days of the date the IOU's notice of NOI acceptance is sent to the customer.

h. The customer will have 60 calendar days from the IOU's notice of NOI acceptance to cause its ESP to submit a DASR.[5] DASRs will be processed using existing processes and timelines in accordance with Rule 22 (or equivalent rule),[6] and eligible service accounts will be switched to DA service on their next scheduled meter read date, or the date specified on the DASR, if different from the next meter read date, depending on when the IOU receives the DASR. Although Rule 22 (at Section E.18) allows the IOU, the customer and the ESP to mutually agree to a different service change date for the service changes requested in a DASR, the IOUs may be unable to accommodate special service change dates during the OEW.

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[4] The threshold is only used for purposes of processing daily batches of NOIs. It is not intended as an increase in the annual limits.

[5] In accordance with the IOUs' current procedures, rejected DASRs must be corrected and resubmitted by the ESP and be acceptable to the IOU no later than 20 days following the conclusion of the 60-day period. DASRs not corrected by the ESP within this time period will be cancelled by the IOU.

[6] The DA Rules for SDG&E are Rules 25 and 25.1. The IOUs' DA Rules generally require that DASRs received by the OIU on or before the 15th of the month will be switched over no later than the next month's scheduled meter reading date for that service account. Under SCE and SDG&E's current DASR process, DASRs that are received by SCE or SDG&E five (5) business days before the customer service account's next scheduled meter reading date will be switched over on its next scheduled meter reading date.

Nothing in this Appendix 2 is intended to rescind Section E.18 of Rule 22; however, it may not be operable during the OEW.

i. If a DASR is not received by the IOU for an accepted NOI by the end of the 60-day period, the customer's NOI will be void.

j. Any NOIs voided for failure to submit a DASR within the 60-day period will not be subject to a three-year minimum BPS commitment period as a result such failure. This exception will apply only to NOIs accepted during the OEW.

k. If the Y1 limit is reached during the OEW, the IOU will stop accepting NOIs, and will begin placing submitted NOIs on a wait-list on a first-come, first-served basis. The wait-list shall have a maximum capacity equal to 25% of the Y1 limit, and will be maintained until the last day of the OEW. Should any room under the Y1 limit become available during the OEW as a result of any voided NOIs, within one (1) business day of any room becoming available, the IOU will notify eligible customers on the wait-list by email of the acceptance of their NOIs. The IOU will continue to issue such email notices, on a 1-business day basis as room becomes available during the OEW, through the last day of the OEW. A customer coming off the OEW wait-list will have 60 days after the IOU's notice of the NOI acceptance to cause its ESP to submit a DASR to the IOU. If a DASR is not received by the IOU by the end of the 60-day period, the customer's NOI will be void, and the exception under Section 7.k for the three-year BPS commitment will apply. The wait-list will end on the last day of the OEW. Any NOIs on the wait-list that were not accepted during the OEW will be void, and customers will be notified that they can begin submitting 6-month advance NOIs as early as July 1, 2010 to switch to DA in 2011. No wait-list will be used after the OEW.

l. The OEW will close 90 calendar days after the Effective Date, or on June 30, 2010, whichever comes first. There will be no OEW in subsequent years of the phase-in period.

m. All LSEs that intend to serve load during 2011 will refile load forecasts for 2011 RA compliance year by May 26, 2010. This revised forecast shall account both for customer migration up to that date, but also to forecast expected customer migration during the second phase of DA access that commences in January of 2011. The updated load forecasts due by May 26, 2010 will be used by the Energy Division and CEC to develop Local RA obligations, inclusive of adjustments, as accurately as possible within the constraints of the 2011 RA filing cycle.

8. Enrollment after the OEW closes:

   a. In 2010:

      - Customers may submit 6-month advance NOIs starting July 1, 2010 to switch to DA in 2011 (Y2). The IOU will accept 6-month advance NOIs up to the Y2 limit. The daily batch process for accepting NOIs (described in 7.d above) will allow for up to a 10 percent (10%) threshold above the Y2 limit.

      - A customer with an accepted NOI will be switched to DA starting in January 2011, provided the customer's 6-month advance notice period has been satisfied and a DASR has been timely received.

      - DASRs will be processed using existing processes and timelines in accordance with Rules 22 and 22.1 (or equivalent rules), and eligible service accounts will be switched to DA service on their next scheduled meter read date, or the date specified on the DASR, if different from the next meter read date, depending on when the IOU receives the DASR. Customers who fail to meet the time limitations and DASR requirements set forth in Rules 22 and 22.1 will be subject to a three-year minimum BPS period as provided for in Rule 22.1 (or equivalent IOU rules).

      - Once the Y2 limit is reached, the IOU will stop accepting 6-month advance notices.

      - If room under the Y2 limit subsequently becomes available, the IOU will update its website to notify customers that it is accepting 6-month advance notices. The IOU will use the same daily batch process described above for accepting NOIs for any room under the Y2 limit.

   b. In 2011:

      - Customers may continue to submit 6-month advance notices after January 1, 2011 to switch to DA in 2011 or 2012, depending on whether there is room available under the Y2 limit. The IOU will accept 6-month advance notices up to the Y3 limit. The daily batch process for accepting NOIs (described in 7.d above) will allow for up to a 10 percent (10%) threshold above the Y3 limit.

      - A customer with an accepted NOI will be switched to DA as soon as possible (depending on whether there is room under the Y2 limit), but in any event starting in January 2012, provided the customer's 6-month advance notice period has been satisfied and a DASR has been timely received. If there is no room available under the Y2 limit, customers who submit 6-month advance NOIs prior to July 2011 may need to remain on bundled service for up to twelve months before being able to switch to DA. In other words, they may have to wait for the Y3 allotment to open up in January 2012 before they can switch to DA. If room under the Y2 limit subsequently becomes available in 2011, some customers may be able to switch to DA prior to 2012, provided the 6-month advance notice period has been satisfied and a DASR has been timely received.

- DASRs will be processed using existing processes and timelines in accordance with Rules 22 and 22.1 (or equivalent rules), and eligible service accounts will be switched to DA service on their next scheduled meter read date, depending on when the IOU receives the DASR. A customer failing to meet the time limitations and DASR requirements set forth in Rules 22 and 22.1 will be subject to a three-year minimum BPS period as provided for in Rules 22 and 22.1 (or equivalent rules).[7]
- Once the Y3 limit is reached, the IOU will stop accepting 6-month advance NOIs.
- If room under the Y3 limit subsequently becomes available, the IOU will update its website to notify customers that it is accepting 6-month advance NOIs. The IOU will use the same daily batch process described above for accepting NOIs for any room under the Y3 limit.

c. In 2012 and 2013:

- The IOU will use the same enrollment process as described above for 2011, using the applicable annual limits, except that a threshold for daily batch processing will not apply to the Y4 limit (because it represents the overall cap).

9. During the phase-in period, the IOU will indicate on its public website whether NOIs (during OEW) or 6-month advance NOIs are being accepted, and update this information regularly, as reasonably necessary, but in no event less frequently than monthly. This information should be sufficient to inform customers and ESPs whether there is room available under the

[7] With the exception that customers who submit 6-month advance NOIs prior to July 2011 may be required to remain on bundled service for longer than 6 months (but not more than 12 months) before switching to DA service, if there is no room under the Y2 limit. In other words, they may have to wait for the Y3 allotment to open up in January 2012 before they can switch to DA.

annual limits during the phase-in or the overall cap after the phase-in. The IOU will provide notice on its public website when the level of annualized sales for customers electing DA service approaches a certain percentage of the annual limit or overall cap (e.g., 95%).

10. Changes in the 12-month usage of DA accounts will be reflected in order to determine the room available under the cap. No customer taking DA service while room was available under the cap will be removed from DA service as a result of growth in DA load.

(End of Appendix 2)

APPENDIX 3

Adopted Temporary Treatment for Local Resource Adequacy Obligations During Direct Access Reopening

We hereby adopt the methodology set forth below in order to fairly allocate local RA costs among LSEs during RA compliance year 2010:

The first step in the methodology is to determine the size of the Local RA obligation associated with a migrating customer. The following calculation is suggested:

Calculate a "Local to Peak Ratio" (LPR) for each IOU service territory. This ratio would be determined by taking the total Local RA obligation in the service area in MW, as adopted by the CPUC decision that established Local RA obligations for 2010, and then subtracting the Local MW that were allocated among all LSEs for Demand Response (DR), Cost Allocation Mechanism (CAM) resources, and RMR Condition 1 (RMR-1) resources. That number is then divided by the total forecasted 2010 coincident peak load in MW of that same IOU service territory (Service Area CPD) that was developed by the California Energy Commission for purposes of establishing 2010 RA obligations. This LPR would be expressed as a percentage. The LPR will be calculated by the CPUC Energy Division and posted to the CPUC website for each service territory alongside the amended 2010 RA Guide and Templates in April of 2010[1].

When a customer seeks to migrate between LSEs after the date of DA reopening, a Customer Local (RA) Obligation (CLO) would be established for that customer, based on the customer's actual recorded Coincident Peak Demand (COPD) in MW at the time of the IOU service territory's 2009 coincident system peak, grossed up by the appropriate Distribution Loss Factor (DLF) for the service area and multiplied by the LPR for the service territory in which the customer is located. The resulting figure would be the Local RA obligation of that customer in MW, the CLO. The LSE losing the load and the LSE receiving the load would stipulate to this figure, which would require only the data establishing the customer's 2009 CPD at the time of the CAISO system peak.

In mathematical terms:

> LPR = Total 2010 Service Area LCR in MW (less Local MW from DR, CAM, and RMR1 & 2)/ Forecasted Service Area 2010 CPD.
>
> CLO = LPR *x* Customer 2009 CPD.

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[1] RA compliance materials for 2008 through 2010 are posted to the CPUC website here: http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_guides_2008-09.htm

In order to simplify the process for this temporary and interim solution, the LSE gaining the additional load would have the option[2] to obtain an allocation of Local RA "credits" from the LSE losing the load, without the need for any actual commercial sale of physical capacity to occur between the two LSEs. Rather, the LSE gaining the load would make a payment to the LSE losing the load, equal to the customer's CLO times an administratively determined price in dollars per kilowatt-year (kW-yr) or kilowatt-month (kW-mo). This payment would be deemed to satisfy the acquiring LSE's Local RA obligation for the remainder of the 2010 compliance year. LSE RA filings from both the LSE that lost the customer and the LSE that gained the customer would need to clearly indicate and highlight the exchange of customer MW and RA capacity if any transferred or sold directly to the other LSE. These rules and implementation procedures will be described in an amended RA Guide and Template for 2010 compliance year, and LSEs will be notified in April of 2010 of the new procedures and rules.

No changes to the current RA compliance process would be required, except that both LSEs would report in their System RA monthly true-ups to Energy Division the amount of the Local RA obligation (the CLO) that was being transferred, and the acquiring LSE would also report the amount of the CLO being satisfied through the default transfer payment, as well as the amount of CLO that was being otherwise satisfied.[3] The capacity that is transferred via the default mechanism would still be obligated by the RA Must-Offer Obligation (MOO) throughout the period in which it was originally shown in the year ahead filing, and the SC for the capacity would be required to demonstrate that in each monthly supply plan. Additionally, in the event that Local RA capacity is not sold to another LSE but is now in excess of the Local RA obligations of the original LSE, the original LSE would still be required to list the capacity to on its RA filing and that capacity would still be subject to the RA MOO via requirement to submit supply plans. LSEs are still under the obligation to demonstrate all Local RA capacity that they have under contract via RA Filings. The current process for monthly true-ups to LSEs' System RA obligations would continue without change. All LSEs that expect to serve load during any month(s) are required to submit a monthly load forecast and System RA filing for each month that the LSE will serve load. Failure of an LSE to demonstrate that it has satisfied the CLO through a timely default transfer payment to the transferring LSE and/or through other means will result in a deficiency in the Local RA obligation of such LSE.

Consistent with proposals in the current RA proceeding (R.09-10-032), in order to reduce administrative complexity, local true-ups shall be completed twice during 2010: once for August

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[2] If the LSE that was gaining the load (the acquiring LSE) can show that it already met some or all of its Local RA obligation with excess Local RA capacity or was able to obtain it from another source, the acquiring LSE would not be required to use this "default" option for some or all of its Local RA obligation. For purposes of these mid-year load migration adjustments only, LSEs gaining load may meet increased Local RA obligations in the PG&E service territory via procurement in either the Other PG&E Areas or in the Greater Bay Area, or any combination of the two. Similarly, the SCE service territory, procurement may be in either the LA Basin or in the Big Creek/Ventura area. Procurement adjustments in the SDG&E service territory must be in the San Diego Area.

[3] *See* fn. 1, above.

and September, and a second time for October-December. For 2010 compliance year, the Local RA true-ups will be performed as follows: On May 31, LSEs (both LSEs that currently serve load and LSEs that assume load during the OEW) shall file their monthly load forecast adjustments for August compliance month pursuant to the current RA schedule. This filing for August will be used to establish adjusted Local RA obligations for LSEs for August and September, 2010. LSEs that do not currently serve load will be required to file with the CPUC and demonstrate RA capacity sufficient to meet their Local RA obligations gained from new customers. On August 2, LSEs will file load migration adjustments to establish Local RA obligations for the months of October, November, and December 2010.

The default transfer payment would provide an administrative price for the transfer of Local RA credits of $24 per kW-year. This amount is intended to reflect only the "premium" value of Local RA capacity over System RA capacity, since the LSEs acquiring new load would still be purchasing any increased amount of System RA capacity required to be shown in its monthly System RA filing under the current RA load migration rules. Rather than a flat $2.00 per kW-month, the monthly prices would be "shaped" to reflect the fact that RA capacity is most valuable during the peak summer months. This shaping would spread the $24 over the months of the year based on the same factors (shown below) that were used to allocate capacity payments under the CAISO's former Reliability Capacity Services Tariff program across the 12 months of the year. In mathematical terms, the transfer payment would be determined as follows:

CLO ***x*** $24/kW-yr ***x*** Shaping Factor for remaining months of 2010.

If, during the course of 2010, the new DA load subsequently switched to another LSE, the same process would be repeated again, and the new LSE would meet the CLO for the new DA load by either making a transfer payment to the prior LSE under the default mechanism or showing that it has obtained Local RA from another source.

This temporary and interim solution shall explicitly apply ***only*** for calendar year 2010, and shall continue or be replaced as a result of whatever solution (if any) is adopted in R.09-10- 032 for the 2011 RA compliance year. If the LSE that was gaining the load already held excess Local RA capacity or was able to obtain it from another source, the acquiring LSE shall not be required to use this temporary and interim option, but shall still be required to make a true-up filing, even if there is no change. To facilitate a smoother synchronization between the phased reopening of DA and the annual RA schedule, the next step in the DA phase-in schedule shall occur on January 1, 2011 rather than April 11, 2011. The use of the January date would allow LSEs' year-ahead Local RA showings for 2011 to reflect any load migration that is expected to occur at the start of the next step of the DA reopening phase-in.

In order to provide Energy Division and California Energy Commission with all necessary documentation for a transfer of local RA obligation, both the losing and gaining LSE shall provide the following information to the California Energy Commission and Energy Division at the time of the local true-ups: CLO for each customer gained and lost, documentation of customer transfer, default transfer payment amount (if a transfer payment has been made), identity (CAISO scheduling resource ID and MW amount) of any local RA capacity transferred, and any other information that may be required by Energy Division and California Energy

Commission to implement this methodology. Energy Division shall publish a template to facilitate this documentation.

Monthly Shaping Factors

	SP-15	**NP-15/ZP-26**
Jan	6.7%	4.9%
Feb	5.0%	4.9%
Mar	5.0%	5.6%
Apr	5.8%	4.6%
May	6.3%	4.8%
Jun	8.3%	5.1%
Jul	15.8%	13.7%
Aug	17.5%	15.3%
Sep	11.7%	13.8%
Oct	5.8%	8.7%
Nov	6.3%	8.8%
Dec	5.8%	9.8%

(End of Appendix 3)

APPENDIX D

PRESS RELEASE ISSUED BY THE
CALIFORNIA PUBLIC UTILITIES COMMISSION
ON
DECISION REGARDING INCREASED LIMITS FOR
DIRECT ACCESS TRANSACTIONS

APRIL 2, 2010
DOCKET NO. E-00000A-02-0051

California Public Utilities Commission
505 Van Ness Ave., San Francisco

FOR IMMEDIATE RELEASE **PRESS RELEASE**
Contact: Terrie Prosper, 415.703.1366, news@cpuc.ca.gov Docket #: R.07-05-025

CPUC ALLOWS NON-RESIDENTIAL CUSTOMERS CHOICE OF ELECTRIC PROVIDER

SAN FRANCISCO, March 11, 2010 – The California Public Utilities Commission (CPUC) today acted to implement a plan to increase the amount of Direct Access transactions within the service territories of California's major investor-owned electric utilities (IOUs), Pacific Gas and Electric Company, Southern California Edison and San Diego Gas and Electric Company.

Direct Access allows eligible customers to purchase electricity from an independent Electric Service Provider rather than from an IOUS and was first instituted as an option for retail electric service throughout California in 1998. Currently, about 5 percent of total retail sales across the state are Direct Access transactions.

The authorization for increased Direct Access is being implemented in accordance with the provisions of recently enacted Senate Bill 695 (Kehoe). SB 695, which was supported by a broad coalition of stakeholders including the Division or Ratepayer Advocates, TURN, and each of the utilities, was signed into law by Governor Schwarzenegger October 11, 2009.

Effective April 11, 2010, all qualifying non-residential customers will be eligible to take Direct Access service, up to specified maximum annual caps that will be phased in over a four-year period. The phase-in approach will be conducted as follows: 35 percent of total allowable DA sales will be allowable in year one, 35 percent in year two, 20 percent in year three, and 10 percent in year four. After the 4-year phase-in period there will be approximately 11 percent of total retail sales being served by entities other than the IOUs. This equates roughly to the historical maximum the state reached in 2001.

The SB 695 cap limits any potential risk associated with reopening of Direct Access by eliminating uncertainty associated with load migration. The adopted phase-in schedule is designed to provide enough lead time for IOUs to account for small shifts in load and thereby avoid unwarranted cost shifting and stranded load.

Additional issues that relate to SB 695 implementation will be addressed expeditiously in a subsequent CPUC decision.

The proposal voted on is available at
http://docs.cpuc.ca.gov/PUBLISHED/AGENDA_DECISION/114734.htm.

For more information on the CPUC, please visit www.cpuc.ca.gov.

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