Core/Non-Core Electric Market Structure Discussion Proposal
By CPUC President Michael Peevey

Introduction

It is difficult to discuss or propose a core/non-core market structure without discussing California's previous retail market restructuring effort. Many academics and others have written papers pointing out the flaws in California's previous actions. One aspect of those earlier restructuring debates deserves prominent treatment: customer choice. In the aftermath of the crisis, we have given comparatively short shrift to worrying about the customers served by California's electric system. What do customers want? The short, anecdotal answer is that they want three things: lower prices, high-quality service, and options (about where they buy their power and what type of power they buy). In numerous surveys, customers, especially residential customers, report that they would actually pay more for green power. Knowing this, it is fair to conclude that, in many instances, the current market structure is not serving customers' needs and wants.

In proposing a new core/non-core market structure, this paper focuses on the customer. Meeting the needs of utilities, independent power producers, and Wall Street, while important, should not be the primary function of the California Public Utilities Commission. We exist to ensure that customers are served.

To that end, this discussion paper proposes a different core/non-core structure from others being discussed.[1] Briefly, it suggests that setting a 500 kW size threshold for customers (not meters) being automatically defined as non-core is satisfactory, as long as aggregation is allowed. It suggests, like the Commission's Division of Strategic Planning (DSP) report, that there are certain preconditions that need to be met before implementing a core/non-core structure, and that the Commission will need at least one year from the time the Legislature acts to ensure that all of the preconditions are in effect. Those include, primarily, mechanisms to guard against cost-shifting, both of past costs and of future utility generation investments, between so-called "captive customers" and those who opt for choice.

[1] See, for example, proposed legislation (AB2006 (Nunez) and AB428 (Richman)), as well as the CPUC Division of Strategic Planning Report of March 15, 2004 titled "A Core/Noncore Structure for Electricity in California."

Practicalities of the Current Electric Market

A great deal of uncertainty remains in the electric market in California, at both the wholesale and the retail level. Companies are risk-averse and long-term investment requires a stable environment that is dependent upon a considerable degree of certainty in the regulatory arena. For purposes of the core/non-core market structure discussion, we assume that we are concerned only with generation costs. Distribution is assumed to be the purview of the investor-owned utilities, and transmission is a separate topic, not addressed in this paper.

For generation investment, merchant generators cannot get financing for investments without the guarantee of a lengthy power purchase agreement from a regulated utility, which in turn requires certainty of cost recovery from ratepayers that can come only from the CPUC.

Despite these uncertainties, we have relatively greater certainty about other aspects of the system. Certain physical realities remain. Those are chiefly two: first, load levels, and load growth, are fairly predictable, at least over the short and medium term. Regardless of who serves that load, it can be counted on to exist and grow, at a modest 2% or so at least, over the next several years. Second, the amount of electric generation available in the state today is measurable. Again, this is regardless of who actually owns the capacity or what entities are proposing to build new generation. So, it is possible to calculate, within reasonable bounds, what the electric supply and demand balance is likely to be over the next few years.

Although not a totally closed system, it is important to remember that both supply and demand are physical realities. When utilities claim that a huge percentage of their load may “depart” under certain core/non-core structures, we should keep in mind that the load is still physically staying in California. We are only talking about the load being served by a different entity. Likewise, when generators claim that capacity will be lost without contracts, the reality is that if a generator is a useful asset, it will likely become operational again at the right price.

Thus, what we are actually addressing with a core/non-core market structure is purely economic policy. We are struggling with how to allocate costs (and therefore risk) among a series of actors in the market: customers, utilities, generators, energy service providers, and, for the last three, shareholders. Each of these actors would like to minimize their risk, and it is the job of regulators and legislators to balance that risk and ensure that it is shared.

The key element, therefore, becomes the application of uniform resource adequacy requirements on all load-serving entities (LSEs) in the system. If all LSEs are required to have under contract sufficient capacity and energy to serve their customers, plus a reserve margin, there should be ample opportunity for investment and profit, while spreading the risk of reliability failure among a number of actors. In meeting the resource adequacy requirements, LSEs should manage a diverse portfolio of types of resources as well as contract terms. There should be business risk for all LSEs, IOUs and ESPs, for prudent portfolio management.

This risk-sharing and cost-sharing is required, not only for the existing system, but also for future generation. To better assess these economic decisions, the sets of costs in the electric system can reasonably be divided into three time periods. These are discussed in the next section.

Temporal Cost Issues

The three logical cost categories that need to be assessed for the commodity cost of electricity include:

1. Pre-crisis Utility Retained Generation (URG) costs
2. Department of Water Resources (DWR) contract costs
3. Recent and future (post-crisis) utility:
    - Power purchase agreements (PPAs)
    - Utility plant

The amount of cost associated with each category is an analytically calculable number. Utilities know the costs of their retained generation, in the past and on an ongoing basis. The DWR contract costs are finite and the time period is fixed. Recent and future investment, either in the form of a physical asset or a contractual commitment, is also knowable. If IOUs served all load, these three categories would form the energy component of customer rates.

Legal and regulatory requirements exist, to one degree or another, that constrain our flexibility in allocating all of these costs. This paper suggests, however, that there could be other creative ways of assessing charges to cover these costs, without creating cost-shifts or potential cost-shifts among customers. The benefit of this new assessment structure would be greater customer choice at an earlier time period.

At the risk of further complicating what has been a contentious and hard-fought coalescence around a direct access cost-responsibility surcharge (CRS) cap of 2.7 cents per kilowatt-hour (kWh), in this paper I suggest that at least the DWR portion of the charge could, and probably should, be reassessed to better reflect the true cost of the power procured on behalf of individual customers.

In simple terms, another approach could be to assess a per-meter monthly charge on each customer that was served by the IOUs at the time the DWR began procuring energy. At the moment, all DWR and URG costs are being assessed on a per-kWh volumetric basis. Proponents of volumetric rates point to the fact that this type of rate design encourages conservation. However, in the case of the DWR costs, they are fixed and unavoidable, and thus conservation by one customer serves to shift those costs onto another customer in the system, by definition. If direct access consumption is lower than anticipated by modelers, for example, more costs are borne by bundled customers, under the current system. Likewise, if direct access load is higher than anticipated, those customers bear a larger percentage of the costs.

If we were, instead, to assess the load of each meter on February 1, 2001, calculate that meter's load as a percentage of total DWR-procured power, and convert that amount into total debt per meter, the charges could be collected on a monthly fee basis from each meter, without regard to the variations in load of each customer. In this way, customers would pay their fair share of DWR costs without creating unintended consequences or perverse incentives for their future electric use. This would operate more obviously like paying off a debt (which most customer groups agree is appropriate), with adjustments needed for that portion of the debt already paid when and if the mechanism is converted to a per-meter monthly charge.

Current and future investments in generation have the same potential to become future stranded costs. Thus, under any core/non-core model, we will need an ongoing mechanism to guard against cost-shifting.

Utilities argue that until their customer base is reasonably certain, they are unable to make long-term investments in generation. The same is likely true for ESPs. Thus, without certain entry and exit rules, no LSE is going to be willing to make long-term investments.

The scenario that most observers are worried about is when an IOU invests in a long-term generation resource for a certain forecasted future load, and then loses that load to a direct access (or non-core) provider. In this situation, the concern is about remaining customers of the IOU being required to pick up the cost of the generation investment.

In reality, if an IOU makes an investment that turns out not to be needed to serve its future retail load, the IOU will sell its excess generation on the wholesale market. If an ESP needs generation resources, it may buy the excess IOU generation. This gives rise to the worry that there could be a so-called “death spiral” whereby IOUs invest in generation for a decreasing customer base; that customer base migrates to direct access or non-core status, forcing IOUs to sell their excess power at a loss on the wholesale market, finally leading to cost-shifts to remaining IOU customers, and further incentive for non-core exit.

Even in this situation, it is also important to keep in mind that the size of the potential cost-shift, however, is not the full cost of the investment in generation by the IOU, but the difference between the wholesale market price and retail rates received by the IOU. This amount should be coverable by instituting reasonable market rules for switching and cost responsibility principles, as discussed further below.

Principles

In offering this alternative proposal for core/non-core structure, the following principles are important to consider:

- Certainty of structure and rules is paramount
- Cost causation
- Rational rate design
- Preserving reliability
- 5-year planning horizons (supply and demand)
- Importance of aggregation as option
- Customer size threshold for non-core

I discuss each principle in more detail below.

Certainty

It is a fairly obvious and often-made point that certainty of market rules promotes investment. Certainty, in this case, means not only a clear market structure, but clear implementation rules and timeframes. We need to establish a definition of which customers are core and which are eligible for non-core; rules for switching from core to non-core status and back again need to be clear and stable; cost responsibility needs to be clear and calculable for customers making economic decisions.

Cost causation

In general, this paper espouses the principle that customers should pay for generation costs incurred on their behalf. If an IOU makes a power plant investment while serving a particular non-core eligible customer, for example, that customer should be responsible for paying its fair share of the cost of that investment, even if it later elects service from an energy service provider (ESP). This, in effect, covers the revenue requirement of a generation investment.

Rational Rate Design

In addition to covering the revenue requirement, a wholesale effort is needed to rationalize the rate structures for many customer classes, to reflect the true cost of serving those customers. Generally speaking, fixed costs should be assessed with a fixed charge, while variable costs should vary by usage levels. Moving toward real-time pricing and other tariff designs that allow rates to fluctuate with costs is not only a principle necessary for a functional core/non-core market structure, it is also likely to be a reasonable precondition.

Preserving reliability

As discussed above, any market structure change should occur only in the context of a stable resource adequacy requirement for all LSEs. If all entities serving customers in the market are required to prove resource adequacy, then the system in general should be resource adequate, regardless of which entity is serving a particular customer. This leads to a discussion of the provider of last resort (POLR) issue. IOUs worry that no matter how the market rules are structured, if some unanticipated situation occurs and there is a system emergency, all customers will expect that they will be able to switch back to their IOU provider and be served. This is a political (and physical) problem rather than a theoretical one. Some academics and others believe that if an ESP is under contract to serve a customer and that obligation cannot be met, then the customer is at risk, and should be allowed to be physically interrupted or not served, if resources are inadequate. (This could require additional advanced metering infrastructure.) Others believe that, politically, this will never happen, and that customers in such situations will always gravitate back to their IOU service, as the POLR, because the political establishment will never allow that kind of economic disruption of customers in the state. This proposal suggests that the IOUs should and will be the POLR, but should be appropriately compensated for fulfilling that role.

Planning horizons

As pointed out in the DSP paper on core/non-core, most customers in the market have a one to two year planning horizon, while most power plants cannot be built without at least a ten-year revenue stream. The need to bridge this gap exists both for IOUs and ESPs, since both want to be able to serve their customers at the lowest cost, which involves some long-term commitments. To balance the risk and allow for reasonable planning horizons, I propose to require a five-year commitment by customers to their core or non-core status. This would mean that customers wishing to become non-core would pay a cost-responsibility surcharge for generation built or contracted for on their behalf while they were served by the IOU. Likewise, a non-core customer who made an initial five-year commitment to non-core status but wishes to switch back to the IOU, would have to pay the market rate for the remainder of the five-year commitment to non-core. Switching among non-IOU providers would not create additional cost-responsibility, beyond the five-year commitment, but if there was any IOU service in the interim, the customer would pay the market rate.

Aggregation

Aggregation of customers under the non-core size threshold, whatever it is finally resolved to be, is of critical importance to satisfying customer needs. For a number of non-core customers, the advantages of non-core service will not be limited to price, but will include such important customer service options as innovative billing and metering services, more responsive customer service representatives, or the ability to serve statewide chain stores through one provider. For example, a fast food chain with locations in all service territories could have one non-core ESP that provides aggregated billing to the corporate headquarters for all locations. No IOU can offer that service, by definition. Most fast food chains would not come close to meeting a 500 kW per month size threshold at each location/meter, but through aggregation, these types of customers' needs can be served.

Aggregation is also an important option for smaller customers wishing to choose green power options. Without allowance for small customer aggregation, retail ESPs with green portfolios would not be able to serve residential customers.

Customer size threshold

If aggregation is allowed, the size threshold required to achieve non-core status becomes less important. A 500 kW threshold for monthly peak demand would create an automatic non-core status only for the very largest big box retail stores and office buildings, plus most industrial customers. A 200 kW monthly peak demand threshold would capture a much larger portion of the commercial market. My preference would be for a 200 kW threshold, but 500 kW is appropriate only if aggregation of smaller customer loads is allowed, as discussed above.

Timing Considerations

In order for a core/non-core market structure to begin, several preconditions should be met, which were discussed in the DSP report and have already been mentioned in this document. These are the following:

- Revisiting the CRS related to DWR costs
- Rules for cost responsibility for new generation
- Adoption of entry/exit/switching rules
- Imposition of uniform resource adequacy requirements
- Rationalization of rate designs
- Treatment of POLR

The importance of each of these issues has been discussed already above. Some, such as resource adequacy requirements, may require modifications to existing CPUC decisions to push requirements to an earlier timeframe. Others may require new work on the part of staff and stakeholders. Thus, I believe that the CPUC should be given one year from the time any legislative change goes into effect creating a core/non-core retail market structure, to conduct a proceeding to ensure that each of these preconditions is met, before the new retail market structure is actually effectuated. This one-year timeframe presumes that any enacted legislation would outline a core/non-core structure, but leave detailed implementation issues to be worked out by the CPUC.

After these details are worked out, the market should be reopened. I disagree with the DSP recommendation tying reopening of the market to the dropping off of existing contract obligations. In reality, many of the customers who would wish to become non-core are already on direct access. Those who are not will be making individual business decisions on the basis of the new rules put in place, and will be negotiating with new service providers. It will take time for such a voluntary market to develop, regardless of the legislative and regulatory changes that are made.

Summary of Proposed Market Structure

In summary, I propose the following definitions of core/non-core structure.

Core customers

Core customers would be any customers with monthly peak demand of less than 500 kW who do not choose to be aggregated and served by a non-IOU electric provider. These customers should, however, be allowed to choose a non-IOU retail option for green power. The DSP paper proposes green choice for customers through the IOU, with ESPs as providers, though not retail providers; the CPUC should explore offering green choice by non-IOU providers as well, with those entities having direct customer interface (as another option). In addition, we should explore expansion of advanced metering infrastructure to serve core customers.

Non-core customers

All customers with monthly peak demands in excess of 500 kW should be automatically considered non-core and should be expected to find their own ESP to provide electricity service, unless they choose to be served by their IOU. See the core-elect description below.

Core-elect customers

These are customers with monthly peak demands in excess of 500 kW who voluntarily choose to be served by their IOU. They should be required to make a five-year commitment to such service at the outset. If they are returning from non-core ESP service, they should be required to pay the market rate for electricity for any remainder of the five-year commitment.

Aggregation

As discussed above, aggregation should be allowed by ESPs of customers with monthly peak demands less than 500 kW to reach that size threshold. At such time, each individual customer being served would be considered non-core aggregation customers. As with other non-core customers, a five-year commitment should be required. Community choice aggregation, already allowed under state law, would be considered under this category of non-core service.