ATTACHMENT1

EXCERPTS FROM

California Independent System Operator

Market Design 2002 Project

Comprehensive Market Design Proposal

April 29, 2002

Both Option 1 and Option 2 meet the reliability objectives of ACAP since both options attempt to derive and assign the peak load ACAP requirements of the ISO. Moreover, both methods are susceptible to variations – Option 1 from variations from historical load patterns, Option 2 from poor LSE forecasting.

4. *Potential Cost Impact on the LSEs*

Option 2 appears less costly for the LSEs, in part because it will be driven by LSE forecasts – which could of course result in purposeful under-forecasting. In addition, since the allocation of the ACAP Obligation under Option 1 will be based on historical data, the allocation could result in a higher obligation if the historical data is not representative of then current conditions.

Summary Comparison of the Options

Criterion	Option 1	Option 2
Ease of forecast/reconciliation	Easier	More difficult
Compatibility with roles and responsibilities	More compatible	Relatively less compatible
Satisfying reliability objectives	Meets objectives	Meets objectives
Potential cost impact on LSEs	Only slightly more cost exposure	Only slightly less cost exposure

Recommendation

Based on the above analysis, and the guidelines described above, Option 1 is recommended. Option 1 is more consistent with the role defined for the ISO is this process – that of ensuring reliable system operations – and is simpler.

5.1.9 ISO Assessment of Compliance With the Monthly Obligation

5.1.9.1 Monthly LSE Certifications

Each month, LSEs will submit completed certification forms to the ISO demonstrating that they have obtained sufficient ACAP for the upcoming month. The certification forms shall, at a minimum, require LSEs to: 1) designate the total amount of ACAP they have procured; and 2) specify how much ACAP is associated with ACAP suppliers that are located in each LRA, the remainder of the ISO Control Area and each external Control Area.

As stated in the April 3 Draft Comprehensive Proposal and reconfirmed here, the monthly ACAP Obligation requires that each LSE obtain an amount of ACAP resources equal to its forecasted monthly peak plus a Reserve Margin, i.e. forecasted monthly peak load times the quantity 1 + Reserve Margin. The purpose of the monthly obligation is for the system as a whole to have access to resources that can reasonably be expected to meet the upcoming month's load with sufficient reserves. Therefore, as discussed further below, resources that will provide ACAP must be specified by point of delivery into the system and demonstrate feasibility of delivery to the Local Reliability Area (LRA) in which the LSE's load is located. The resources that satisfy the ACAP requirement can be selected to meet load in its anticipated shape; that is, each LSE will be able to procure the portfolio of ACAP resources that best satisfies its hourly load requirements for a given month.

5.1.9.2 ACAP – Monthly Obligation Assessment Options

Statement of the Issue:

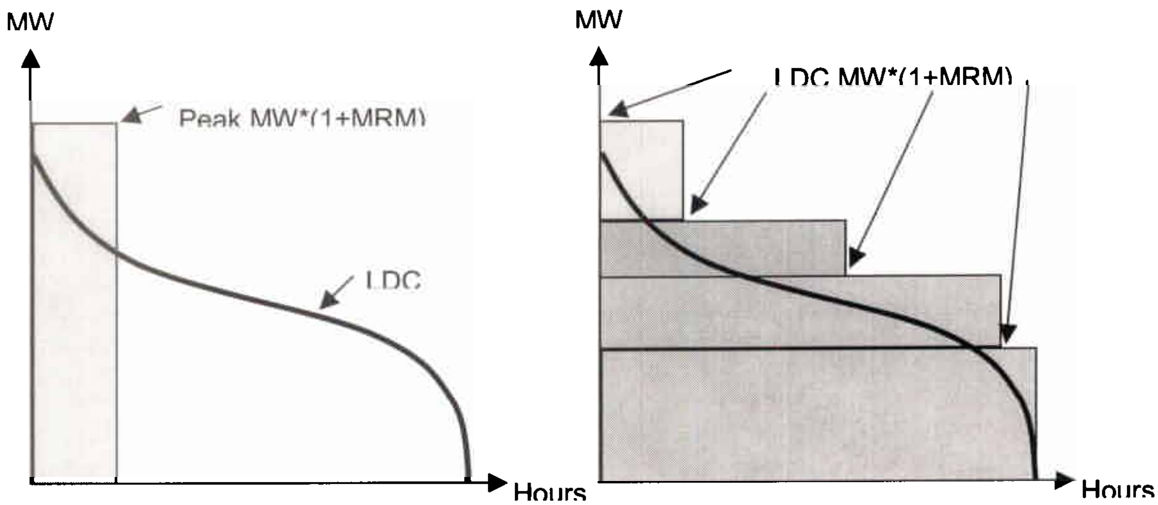
In its April 3 Draft Comprehensive Proposal, the ISO identified two options for measuring compliance with the monthly ACAP obligation as follows:

> ***Option 1:*** Measure an LSE's resources against their peak demand (the hours with a high-probability of being the peak) because it is that load which puts the greatest demand upon the generation resources of the system and, other things being equal, the greatest strain on the system reliability.
>
> ***Option 2***: Measure an LSE's resources against their load for the entire month using a monthly load-duration curve. Under this approach, a LSE could specify the portfolio of resources that it would use to satisfy its hourly load requirements (interruptible load, peakers, hydro, QFs, nuclear, energy contracts, ACAP contracts, etc.). This option would take into account energy and emission limits, as well as planned outages.

Under both options the requirement would be to demonstrate that a LSE has secured resources to cover the product of (1 + MRM) and their forecast load, where MRM is the monthly reserve margin.

***Comparative* Analysis of the Options:**

The following figure schematically demonstrates the two options, using a hypothetical monthly load duration curve (LDC) for a given LSE.



Option 1 Option 2

Under Option 1, the LSE would be responsible to cover the forecast monthly peak load (including the MRM) for a specified number of hours (forecast peak load duration). Under Option 2, the forecast monthly LDC (including the MRM) is approximated by a number of blocks with different durations (including one block for the total number of hours of the month, one for the duration of the monthly peak, and one or more blocks with durations between the two.

The ISO has identified the following criteria for use in evaluating the two options:

- Relative ease or difficulty of forecast and forecast reconciliation;
- Compatibility with roles and responsibilities of the ISO (centralized vs decentralized decision making);
- Satisfying reliability objectives of ACAP;
- Market power mitigation;
- Potential cost impact on LSEs; and
- Incentives for generation investment;

It is assumed that under *both* options the ACAP resources are available for a designated number of hours during the month, but that their exact allocation (commitment) for the different hours of the day is accomplished in the day-ahead (and where relevant hour-ahead, or pre-dispatch) time frame through a combination of SC self scheduling, Unit Commitment Service (UCS) and Residual Unit Commitment (RUC) processes to meet the ISO's reliability objectives. In other words, operational reliability of the system is a centralized function delegated to the ISO (under AB1890) rather than a decentralized task left at the discretion of the transmission users (SCs). If a LSE is short in satisfying its ACAP obligation and is willing to accept firm load curtailment as a consequence, the final decision whether to curtail the deficient SC's load or commit a pool of resources (and charge a deficiency charge to the SC) is left to the ISO based on system reliability considerations (vulnerability to cascading outages, etc.).

1. *Relative ease or difficulty of forecast and forecast reconciliation*

Option 1 involves forecasting the monthly peak and its duration. Option 2 requires determination of the monthly load duration curve (or its approximation by a number of blocks). Option 1 is easier to implement and reconcile the ISO and LSE forecasts.

2. *Compatibility with roles and responsibilities of the ISO*

Option 1 is more in line with the role and responsibility of the ISO, namely ensuring reliability of the system during high demand periods. It leaves the responsibility to "meet the demand" during the rest of the hours to the LSEs, as overseen by the appropriate regulatory agencies. Option 2 may be construed by some (e.g., the State entities) to be an unnecessary intrusion by the ISO outside the peak demand hours – the hours most likely to directly impact, from a total system resource perspective, the ISO's ability to maintain system reliability.

3. *Satisfying reliability objectives of ACAP*

Both Option 1 and Option 2 meet the reliability objectives of ACAP since the ISO can allocate the ACAP resources to cover the peak demand hours of the day under either option. However, Option 2 may be considered slightly superior in that it ensures supply adequacy during shoulder and off-peak hours as well. This fact, of course, needs to be balanced against the appropriate role for the ISO in making such determinations.

4. *Market power mitigation*

Under otherwise comparable structural conditions (ownership and control concentration), the deeper the supply stack, the lower the potential for the exercise of market power (the less the probability of having pivotal suppliers). Option 1 presumably provides for a deep enough supply stack to mitigate system-wide market power during peak hours. Option 2 provides a somewhat superior protection since it ensures supply adequacy for all hours.

5. *Potential Cost Impact on the LSEs*

Option 1 appears less costly for the LSEs to satisfy their ACAP obligation. However, since the exact allocation (commitment) to meet the peak load is driven by reliability objectives, the cost of ACAP under the two options may not be substantially different. In other words, the ACAP providers would internalize the risk of being committed by the ISO (i.e., having to sell only non-firm energy exports in order to ensure adequate ACAP for the ISO's "commitment" call option) for almost as much capacity under Option 1 as Option 2.

6. *Incentives for generation investment*

Option 2 may provide for stronger incentives for generation investment than Option 1 since under Option 2, the LSE would have to line up a variety of contractual arrangements with different time durations (base, cycling, peak). Thus, Option 2 may provide incentives for a more diverse set of potential new generation and demand-response resources. Nonetheless, both options will provide a platform for new investment. Moreover, with respect to resource diversity, the ISO believes that state public policy considerations (fuel-type diversity, environmental considerations, the development of demand response programs) will be a critical and important driver in deciding that issue.

Summary Comparison of the Options

Criterion	Option 1	Option 2
Ease of forecast/reconciliation	Easier	More difficult
Compatibility with roles and responsibilities	More compatible	Relatively less compatible
Satisfying reliability objectives	Meets objectives	Meets objectives
Market power mitigation	Effective	Only slightly more effective
Potential cost impact on LSEs	Only slightly less expensive	Only slightly more expensive
Incentives for new generation investment	Lower	Higher

Recommendation

Based on the above analysis, and the guidelines described above, Option 1 is recommended. Option 1 is more consistent with role defined for the ISO is this process – that of ensuring reliable system operations.

5.1.10 LSEs Daily Obligation

In the April 3 Draft Comprehensive Proposal, the ISO stated that on a daily basis, each LSE will be obligated to provide and schedule the ACAP resources necessary to satisfy its forecast load requirements. The ISO identified two options for satisfying the daily obligation.

Option 1: Require that a LSE provide and schedule an amount of ACAP resources equal to its next-day's hourly load, plus a fixed percentage (such percentage based on the MRM defined earlier). This option would enable LSEs to shape their ACAP resources to satisfy their hourly load requirements.

Option 2: Require that each LSE make available to the ISO, on a daily basis, their entire monthly portfolio of ACAP resources. The ISO would then determine which resources it must commit for dispatch in order to serve the next day's forecast load. The ISO would optimally commit such resources based on their bids through its unit commitment process. The ISO recognizes that, in light of the strong availability requirements placed on resources, this approach may be onerous and result in higher ACAP costs.

Attachment 2

Determining Allowable Resources' Qualified Capacity Value

CAISO Resource Adequacy Working Group
Allowable Resources Subgroup
November 5, 2002

Document Description

Purpose of Allowable Resources Sub-Group Activity

On July 17, FERC approved various aspects of CAISO's MD02 filing. CAISO was directed to hold technical conferences with stakeholders to, among other things, address the issue of how to assure future generation adequacy. The Resource Adequacy Working Group (RAWG) was created as a result of the MD02 technical conference process. Its mission is to "develop a consensus recommendation for a mechanism to ensure an adequate quantity of electrical resources (generation, transmission and demand-side) are available to meet anticipated peak load requirements." The Allowable Resources Sub-group was formed to develop a methodology for quantifying and evaluating present and future loads and resources of the Load Serving Entities.

CPUC Related Activity

CPUC initiated a proceeding (R.01-10-024) to establish energy procurement standards for the IOUs. Much of the type of information that the Allowable Resources Sub-group is charged to develop is also being addressed in this CPUC proceeding. For instance, on October 24 the CPUC ordered the IOUs to file modified short-term procurement plans November 12 and long-term procurement plans April 1, 2003. This RAWG activity could be enhanced by having available to it some of the information gathered in this related CPUC activity. Certain stakeholders intend to seek release of this CPUC information that could be used in achieving the sub-group's charter. Specifically, load, resource, and reserve information by utility is needed to assess how various types of resources options are and can be used to meet future procurement obligations.

Allowable Resources Qualified Capacity Matrix

Notes:
- This matrix is intended to accommodate both long term and short-term resource adequacy.

Allowable Resource	Proposal	Comments
Thermal/Nuclear	Each supplier's portfolio of thermal units will have its total portfolio capacity (sum of all units' PMax on file with CAISO) adjusted to reflect historical EFORd. For purposes of the forward (annual or month-ahead) available capacity, this capacity would be derated based on historical forced outages of the resource. The derate will be based on the ratio of forced outage hours during the reference period (e.g. a year) divided by the sum of the forced outage hours, scheduled maintenance outage hours, and the hours of market participation, where the hours of market participation include hours for which the resource was scheduled or bid (even if not selected) in the market. The historical forced outages may be adjusted to reflect, as appropriate, any extraordinary outages during the historical period. On a forward basis (one month and longer), the equivalent forced outage methodology described above applies. For periods of less that one-month, derate would not apply and qualified capacity would be based on available plant Dependable Capacity (Pmax) without adjustments for expected forced outages.	• This proposed methodology must be consistent with the way the operating reserve margin is established in order to avoid potential double counting of forced outages. Historically, forced outages have been implicitly included in the reserve margin requirement for each specific system. • Must ensure that the de-rating approach, which is used to compare different plants on comparable terms, does not lead to development of excess reserves. • Time frames need to link to obligations and penalties (This presupposes what the capacity values are used for - Hendry) • This methodology pre-supposes continuation of the must-offer requirement (i.e. hours in which unit bid/scheduled into market) otherwise it would undercount potential resources and create gaming opportunities. - Hendry • Unanswered question from two meetings ago now; what is difference in accuracy between use of 1, 3 or 5 year historical averages - Hendry • Would there be requirements for mandatory maintenance/staffing levels to ensure availability? - Hendry • How are plant upgrades treated which should improve prospective availability? - Hendry • A demand-related Equivalent Forced Outage Rate (EFOR) represents the probability that a generating unit

Determining Allowable Resources' Qualified Capacity Value
(Allowable Resources Subgroup – November 5, 2002)

		will not (or did not) meet its required generation demanded by dispatch.
Hydro	Short-term (less than 1 year): Hydro units' available capacity will be determined based on similar month historical data (energy plus undispatched operating reserve), adjusted for the current and projected reservoir/head level for hydro storage systems or stream flow for run-of-river systems.	• Is it feasible to make an adjustment (up or down) based on actual near-term water conditions and measured snow pack for resource availability over the next 3-12 months? • How/who determines reservoir level/stream flow? Is there a consistent agreed-upon methodology? What is forum for determining, and who determines? - Hendry
	Long-term (more than 1 year) - Hydro units' available capacity will be determined based on the sum of lowest energy production and undispatched operating reserve capacity self provided or awarded in MWhs in the on peak hours during the same month over the past 5 years (period for which CAISO data is available), a longer historical period would provide higher confidence. This could be comparable to a "critical" water criterion. If necessary, available capacity for units represented as "Psuedo units" would be based on comparable data provided by resource owner.	• Look at historical monthly stream flow and go out 2 st. dev. units from mean as an expected minimum amount • Going out 2 SD creates a "1-in-20" (i.e. less than 5% probability) - Hendry • Again, what is difference in use of longer, historical time span? – Hendry • SVP: Use of worst-case scenario for hydro is inconsistent with treatment of other resources. Should use energy production and undispatched operating reserve during reference period (e.g. a year We support Anaheim's comment "Anaheim pointed out that hydro with storage is much more reliable than run of river" Hydro storage capabilities must be taken into consideration.
Imports	**Long-term** (more than one year): Total firm import capability will be adjusted to reflect historic dependable transmission capability into the control area with appropriate treatment of existing contract capacity and adjustments to reflect transmission upgrades. The obligation of the LSE is:	• Any path derate would affect all users of that path proportionately after consideration of priority order. • How are non-firm imports over unconstrained lines addressed? • CAC – For long-term, an LSE could be required to execute a financially firm contract (akin to the WSPP firm product agreement) for the associated amount of power to count as an eligible resource. CAC feels this option is a

	• <u>Option 1</u>: LSE needs to specify amount and path, and needs to identify firm system contract and transmission rights (CRRs). This approach may not be consistent with CRR allocation of less that 100% of ATC in long term, • <u>Option 2</u>: LSE needs to specify amount of expected import (by path?), but does not need to identify the firm resource contract or firm transmission. **<u>Short Term</u>** <u>(less than one month)</u>: Firm import contracts with adequate congestion revenue rights (CRRs) will count on a commensurate basis as the firmness of their supporting CRRs.	reasonable balance between Option 1 and 2. As compared to the Option 1, it is not as onerous since it does not require the identification of a "system" contract or the need to have procured a firm transmission path. This should give the selling party greater flexibility to make the necessary arrangements to ensure delivery, but still be required to pay for the power. It is superior to Option 2, which contains the extraordinary proposal of simply having to designate an expected amount of available power to count as a capacity resource. CAC believes Option 2 can easily be gamed and would be subject to a never-ending debate on how much imports can be expected to be available from outside California.
QF Generation	Available QF generation will be evaluated on an individual technology and contract basis. **Wind:** Capacity value = historical MW production in (super?) on-peak hours in same month **Cogeneration:** Same as thermal **Biomass:** **Solar:** Same as wind **Geothermal:** Historical production with adjustment for declining resource capacity **Small Hydro (run of river):** • <u>Short-term (less than 1 year):</u> Hydro units' availability will be determined based on similar month historical data (energy plus undispatched operating reserve), adjusted for the current and projected reservoir level	• Because locational information of the QF is required, and because of QF buyout activity, each QF contract should be assessed separately for dependable capacity. (we are now going to assess 800 separate QF contracts?) • As the intermittent resource component of the portfolio increases, the importance of proper accounting for these resources likewise increases. • With the expected increases in QF or new renewables capacity occurring in the next few years, a 10-year average may not be appropriate. In addition, the coincidence of some types of production may need to be studied further to better understand how to accurately assess the firm capacity value of some types of resources. • To the degree QFs are aggregated, location plays an important factor in that resources would need to be aggregated consistent with transmission capability. • SCE proposal – three major categories: 1) historical QFs

	and stream flow. • <u>Long-term (more than 1 year)</u> - Hydro units' availability will be determined based on the sum of lowest energy production and undispatched operating reserve capacity self provided or awarded in MWhs in the on peak hours during the same month over the past 5 years (period for which CAISO data is available), a longer historical period would provide higher confidence. This could be comparable to a "critical" water criterion. If necessary, availability for units represented as "Psuedo units" would be based on comparable data provided by resource owner.	(disaggregated by technology and type of contract), 2) new QFs (disaggregated by technology and type of contract), and 3) new alternative technologies (ones without an existing track record). The reason for this breakdown is that many existing QF contracts have performance targets and incentives to meet the targets. Existence of incentives can potentially increase reliability above what it otherwise would be without the incentives and should therefore be explicitly factored in. • How are prospective rate-design changes addressed • For thermal units, anomalous operations can be thrown out, why not the same with QFs • Why 10 years for QFs, one-year for thermal?
Capacity/Energy Contracts (including Existing Import Contracts)	**Existing Contracts**: Full value of contract on a monthly basis. Adjusted to reflect historical dispatch non-performance **New Contracts**: <u>Option 1</u>: Full value of contract on a monthly basis. Otherwise no difference in treatment of existing and new contracts. This option allows Firm LD (non generator specific) contracts. <u>Option 2</u>: Separate treatment for existing vs. new contracts. New PPAs shall explicitly identify the amount of qualified capacity included in the contract (i.e. pointing to physical portfolio of resources). Qualified capacity shall be determined for each supplier using the methods defined herein for each resource type (e.g., thermal resources'	• Ignores probabilistic availability - Hendry • EFOR adjustment assumes must-offer requirement - Hendry • Wholesale Marketer (AEP/UBS) proposal: Future firm contacts need not be assigned to specific resources 3 years out but could be assigned specific resources 1 month out (see attached document – Resource Adequacy – AEP – Contracts). • Strategic Energy: Firm LD contracts do not have to point to a unit. Unit identification is done day-ahead. Contract provisions let "unit-specific" provider off the hook if the unit is unavailable. This is not acceptable for our necessary standards of reliability. The provider must be committed to deliver his energy. The only way that is accomplished is through Firm LD deals. Obligation, if any, to prove availability, is on suppliers. They will need to show their contract portfolio to ITP to prove that they have not sold "short". Firm LD contracts are no different than imports

	qualified capacity will be based on Net Dependable (is this the same as Pmax?) Capacity, adjusted for historical EFORd).	(only they are more reliable). • SVP: Supports Option 1 and the above comments from Strategic Energy.
New Generation (including Intermittent Resources)	New generator projects must provide periodic status reports on permitting, interconnection agreements and other critical milestones. New projects will have available capacity based on comparable unit EFORd (thermal resources) or historical production levels during peak periods (intermittent resources). Intermittent resources include merchant wind and solar generation. These resources would be treated the same as intermittent QF generation.	• New projects will have qualified capacity based on comparable unit (thermal resources) or historical energy source potential by location (intermittent resources). (e.g. average wind speed, by location, during the peak load hour for same month over the last five years) • What if there is no comparable unit or it's a new technology? - Hendry
Run Hour Limit	Resources are scheduled as available within the constraints of their operating requirements. Resources with run-hour limitation above some threshold amount (e.g., 200 hours) shall have their qualified capacity determined using the derate method defined herein. Units having run-hour limitations less the threshold amount shall be additionally adjusted to reflect that run-hour limitation.	• This class represents a relatively small portion of total available resources and could simply be factored into self-provided operating reserves. A typical resource in this class could be a CT with an environmental run-time limit of less than 200 hours per year or a hydro unit that schedules output for less than 200 hours per year. • Example: A 100 MW unit with a derate of 10% for forced outage would have an equivalent rating of 90 MW. If this same unit had a run-hour limit of 100 hours and the run-hour limitation threshold was 200 hours, then this unit would be subject to an additional de-rate to reflect that it was available less than the threshold amount of 200 hours. The derate would not necessarily be a 50% derate. • This requires a probabilistic assessment of how often resource might be expected to run and the peak hours expected to be covered. - Hendry
Demand Response	Demand resources' available will be based	• Demand resources' qualified capacity will be based on the

	on the interruptible MWs demonstrated during periodic tests.	interruptible MWs demonstrated during periodic tests or actual responses during shortages. • Questions about the periodic tests. - How often? - What if a significant amount of new participants enroll since the last test? - What if the last test did not have the exact same atmospheric conditions? How do you correct or modify the results • .So we're going to arbitrarily tell industries to shut down for an afternoon just to verify compliance. What is the economic cost to the economy of this? – Hendry • Existing interruptible contracts do not contain testing provisions – Hendry • Ignores price-driven demand response programs - Hendry • Ignores rate design changes - Hendry
Deliverability/ Locational Requirement	ISO identifies local generation requirement for reliability. ISO analysis would include benefits of firm transmission projects. LSEs with load located in a transmission-constrained area would need to acquire the identified amount of their capacity requirement within the same transmission constrained area.	• Measures capacity available to serve the total load. • SVP: A financial transmission right (FTR) or existing transmission contract (ETC) should be adequate to ensure deliverability. LSEs should be allowed discretion in sourcing generation from various locations. Such flexibility will help minimize the costs of serving load and provides incentives for efficient expansions of the transmission system if doing so is cheaper than acquiring FTRs or building generation locally. An inflexible locational requirement could also lead to severe cost impacts on LSEs with existing supply contracts, which were entered into under a different market structure.

Determining Allowable Resources' Qualified Capacity Value

(Allowable Resources Subgroup – November 5, 2002)

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