

**BEFORE THE  
PUBLIC UTILITIES COMMISSION  
OF THE  
STATE OF CALIFORNIA**

Order Instituting Rulemaking to Consider	)	Rulemaking No. 08-01-025
Annual Revisions to Local Procurement	)	(Filed January 21, 2008)
Obligations and Refinements to the Resource	)	
Adequacy Program	)	
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**OPENING COMMENTS OF  
THE CALIFORNIA WIND ENERGY ASSOCIATION**

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On Behalf of  
**THE CALIFORNIA WIND ENERGY ASSOCIATION**

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Pursuant to the schedule established in this proceeding, the California Wind Energy Association (CalWEA)<sup>1</sup> respectfully submits the following comments on revisions to the Commission’s rules for determining the resource adequacy (RA) values of intermittent resources, including California’s significant and growing wind resources. Page 6 of R. 08-01-025 made clear that this case will review the “rules for counting the qualifying capacity of various resource types, including, in particular, intermittent and demand response resources.”

I. SUMMARY

The purpose of the Commission’s resource adequacy program is to ensure the reliability of California’s electric system. Although output at system peak is one aspect of a generator’s contribution to system reliability, it is not a completely accurate metric. The contribution of intermittent generation, including wind, to system reliability is a complex question. Given the state’s commitment to the development of renewable resources, this is a question that should be answered using the best available, state-of-the-art methods, not by rules of thumb. In the Renewable Portfolio Standard (RPS) program, sophisticated reliability models have been used to determine the capacity value of intermittent renewables, including wind. Similar techniques are

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<sup>1</sup> CalWEA is a non-profit corporation supported by members of the wind energy industry, including component manufacturers, project developers and owners, support contractors and others.

widely used in the rest of the U.S., as well. The current RA counting rules for wind are broadly consistent with the results of these more sophisticated analyses. Accordingly, CalWEA believes that the existing RA counting rules for intermittent renewables should be retained pending the completion of updated studies of the contribution to system reliability from renewables using “best practices” methods. If the current RA counting rules for intermittents are changed, the new rules should reflect expected wind output weighted by a measure of system reliability, such as the load-based weights proposed by Energy Division in its Proposal 5B.

CalWEA strongly opposes the proposals to use an “exceedence” method to determine the RA contribution of wind. Such approaches result in a double de-rating of wind generation, once to reflect the intermittency of wind output, and then again because wind output does not fit the typical profile of a baseload resource. Such *ad hoc* methods assume that wind generation above a very low level makes no contribution to system reliability, an assumption that is disproved by more sophisticated reliability models. ERCOT, the control area with the largest amount of installed wind capacity in the U.S., recently moved away from the use of such a method to determine the contribution of wind to reserve margins in Texas, citing a concern with this double de-rating of wind resources. ERCOT now uses metrics developed by the more sophisticated reliability analysis that the Commission has used to determine wind’s capacity value for the RPS program. Finally, the exceedence methods would require the NQCs of individual wind generators to absorb virtually the entire impact of ambient conditions on wind output, while fossil-fueled generators would enjoy NQCs that include no adjustments for ambient conditions or forced outages (which can be significant for thermal generation, particularly at dry-cooled plants). As a result, fossil generation would have all of the impacts of ambient conditions and forced outages absorbed in the 15% planning reserve margin, while intermittent renewables would receive almost no benefit from the planning reserve margin, but would bear virtually all impacts from ambient conditions and outages in their NQCs. This outcome would discriminate unfairly against intermittent renewables, and run counter to the Commission’s efforts to encourage these preferred resources.

## II. THE PURPOSE AND GOALS FOR THE RA PROCEEDING

In deciding whether to modify the RA counting rules for intermittent generation, the Commission should first review and restate the fundamental purpose of the RA program. This review is essential, because several parties will attempt to frame much too narrowly the issue of the RA counting rules for intermittent resources. Decision 04-01-025 set forth the purpose and policy framework for the RA program:

Resource procurement traditionally involves the Commission developing appropriate frameworks so that the entities it regulates will provide reliable service at least cost. This involves determining an appropriate demand forecast and then ensuring that the utility either controls, or can reasonably be expected to acquire, the resources necessary to meet that demand, even under stressed conditions such as hot weather [footnote omitted] or unexpected plant outages. ‘Resource adequacy’ seeks to address these same issues. In developing our policies to guide resource procurement, the Commission is providing a framework to ensure resource adequacy by laying a foundation for the required infrastructure investment and assuring that capacity is available when and where it is needed.<sup>2</sup>

As set forth above, the purpose of the RA program is to provide “reliable service at least cost.” The focus of the program is enhancing system reliability. CalWEA expects parties to attempt to argue that the purpose of the RA program is the narrower goal of serving demand during the monthly system peak hour. Although providing capacity during the system peak hour is one aspect of reliability, it does not fully measure a resource’s contribution to reliability – indeed, it is a simplified measure, because an electric grid is at a significant risk of failing to meet load in many hours, not just in the peak hour.<sup>3</sup> For example, **Table 1** shows the system emergencies that the CAISO has declared since 2002, the average load on the system during each emergency, and the system peak load in that year. Although several CAISO emergencies have coincided with monthly or annual system peak hours, many others have not, and some have occurred at demands lower than 95% of the annual peak. Enhancing reliability and ensuring resource adequacy are not

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<sup>2</sup> D.04-01-050, mimeo at 10-11.

<sup>3</sup> Indeed, in D. 04-10-035, which implemented the RA program, the Commission clarified that the intent of the RA obligation is not limited to serving the single peak hour, but rather the set of hours whose demands are within 10% of the monthly peak. D. 04-10-035, at 10 and Finding of Fact 1 and Conclusion of Law 2.

**Table 1**

**CAISO System Stage 1-2-3 Emergencies in 2002 to 2007**

Year	Date	Day	Actual Peak Demand (MW)	Stage 1	Stage 2	Stage 3	Hours Duration	Average ISO Load During Event	Annual Maximum Load	Event Load Over Annual Maximum
2002	7/9/2002	Tuesday	41,838	1440-1900			4.3	41,193	42,352	97%
2002	7/10/2002	Wednesday	42,441	1430-1759	1500-1759		3.5	41,202	42,352	97%
2003	5/28/2003	Wednesday	39,577	1500-1759			3.0	38,806	42,581	91%
2004	03/29/04	Monday	32,649	1350-1929			0.6	31,830	45,562	70%
2005	07/21/05	Thursday	44,652		1432-1730		6.50	41,492	45,380	91%
2005	07/22/05	Friday	44,048		1354-1800		4.1	43,532	45,380	96%
2005	10/14/2005	Friday		1425-1715			2.8	33,581	45,380	74%
2006	07/22/06	Saturday		1312-2000			6.8	46,629	50,198	93%
2006	07/24/06	Monday	50,270	1000-2100	1300-2100		11.0	48,188	50,198	96%
2006	07/25/06	Tuesday		1300-2000			7.0	47,758	50,198	95%
2007	08/29/07	Wednesday		1520-1723			2.0	48,311	48,535	99.5%

Source: CAISO Alert, Warning and Emergences (AWE) Record.

just about meeting load during the peak hour. Indeed, utilities often use complex reliability models that calculate, in every hour, the loss of load probability (LOLP) or other similar metrics of system reliability, such as the loss of load expectation (LOLE) or expected unserved energy (EUE). Such models show that the risk of outages is not focused entirely on the peak hours.<sup>4</sup> For example, Attachment A is Southern California Edison’s calculation of its loss-of-load expectation (LOLE) for its system, by time-of-use period, as filed in Phase II of its current general rate case, A. 08-03-002 (Exhibit SCE-2). This reliability model shows that 70.1% of SCE’s LOLE is attributable to the summer on-peak period, the same period over which the RA value of intermittent generation is calculated under today’s RA counting rules.

D. 04-01-050 also recognized correctly that the implementation of resource adequacy policies can have a significant impact on both the resource mix in California and on electric rates.<sup>5</sup> If too-stringent resource adequacy requirements are imposed, the utilities may only be able to meet them by installing gas-fired peaking capacity, which would run counter to the state’s preferred “loading order” of energy efficiency, demand-side management, and renewables. Conservative RA policies also may result in additional ratepayer costs that exceed the value of the added system reliability. As discussed below, CalWEA has serious concerns that some of the proposals that parties have advanced for the RA value of intermittent resources will both discourage the development of preferred renewable resources in California and unnecessarily increase ratepayer costs. The Commission needs to take care to craft RA counting rules that do not discriminate against renewable resources and that do not apply more stringent RA counting rules to renewables than to other types of resources.

The Commission is well aware that the RA value of intermittent resources, and particularly of wind generation, is not a simple problem. The Commission recognized in D. 05-10-042 (at 72) that the issue of the RA value of intermittent resources is “surprisingly complex.”

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<sup>4</sup> For example, energy-limited hydroelectric resources and maintenance on thermal facilities can be scheduled such that the maximum amount of generation resources are available to serve summer peak demands. If a portion of those resources are not available in other high-demand, near-peak hours, then those hours may also carry relatively high risks of outages.

<sup>5</sup> D. 04-01-040, at 15-17.

The Energy Division's *2007 Resource Adequacy Report (2007 RA Report)* shows clearly that a wide range of values can be derived for the RA value of wind, depending on the counting rules used. Given this complexity, and given the importance of wind generation to meeting California's renewable goals, CalWEA implores the Commission to adopt an RA value for wind that is supported by analysis using the state-of-the-art, best practices in this area. Fortunately, as discussed in the next section, such rigorous tools exist, have been used in California in the past, and are being used today in California and other states to address this important issue.

III. THE COMMISSION SHOULD ADOPT AN RA VALUE FOR INTERMITTENT RENEWABLES THAT IS SUPPORTED BY STATE-OF-THE-ART RELIABILITY MODELS, SUCH AS THE ELCC APPROACH USED IN THE RPS PROGRAM.

The RA program is not the only context in which the Commission has faced the issue of the value of intermittent resources in providing reliable capacity for the California electric system. The Commission also has had to assess the capacity value of such resources in designing the "least-cost, best-fit" (LCBF) analysis that the utilities use to evaluate bids from new renewables submitted under the Renewables Portfolio Standard (RPS) program. In Decision 03-06-071, which established the basic policies and procedures for the RPS program, the Commission directed the utilities to assess the capacity value of intermittent renewable resources, including wind, using the results of a 2003 study that the Commission and the California Energy Commission (CEC) conducted on the integration of renewable resources into the California grid (the "Integration Study").<sup>6</sup> The Integration Study was prepared by Brendan Kirby of Oak Ridge National Laboratory (ORNL), Michael Milligan of the National Renewable Energy Laboratory (NREL), Yuri Makarov and David Hawkins of the CAISO, and Kevin Jackson and Henry Shiu of the California Wind Energy Collaborative at the University of California, Davis. Messrs. Kirby and Milligan are leading U.S. researchers on renewable integration issues, and the remaining authors have considerable expertise on the technical aspects of operating the California grid and on wind generation in California.

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<sup>6</sup> D. 03-06-071, at 30. The Integration Study is available on the CEC website at [http://www.energy.ca.gov/reports/2004-02-05\\_500-03-108C.PDF](http://www.energy.ca.gov/reports/2004-02-05_500-03-108C.PDF).

The Integration Study used a state-of-the-art methodology – the Effective Load Carrying Capacity (ELCC) approach – to determine the capacity value of California wind resources. The Integration Study explains this methodology as follows:

Intermittent generators have capacity value if they increase the reliability of the system, even if the forecasts are not accurate. The best method for determining capacity value of intermittent generators is to calculate their effective load carrying capability (ELCC). This requires a reliability model that can calculate loss of load probability (LOLP), loss of load expectation (LOLE), or expected unserved energy (EUE). ELCC is a way to measure a power plant’s capacity contributions based on its influence on overall system reliability. Using a measure such as ELCC, all power plants with a nonzero forced outage rate have an ELCC that is less than rated capacity (barring unusual plants with artificially low-rated capacity with respect to actual achieved capacity). The ELCC measure is often used as a way to compare alternative power plants, and can be easily applied to intermittent generators as well. A power plant’s ELCC is typically calculated with an electric system reliability model or by a production-cost model.<sup>7</sup>

Thus, the ELCC analysis of a generating resource is a sophisticated measure of “a generator’s contribution to the reliability of the overall electrical supply system.”<sup>8</sup> The ELCC approach uses an hourly reliability model of the CAISO system to calculate the loss-of-load probability (LOLP) across all 8,760 hours of the year, adds a generation resource to the system, and then determines how much additional load the system can support (i.e. “carry”) while maintaining the original LOLP.<sup>9</sup> Dividing this additional “carried” load by the nameplate capacity of the added resource yields the resource’s ELCC, expressed as a percentage. The Integration Study found that the ELCCs of wind generation in the major wind resource areas (WRAs) in California range from 22% to 26%, and average 24%.

Importantly, the ELCC measures the capacity value of a resource across all hours of the year, and does not focus on just a few peak hours. Even though a resource may have low output during the peak hour with the highest demand, that resource can still make a significant contribution to the reliability of the system if it has significant output in other high-demand,

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<sup>7</sup> See Integration Study, at 2.

<sup>8</sup> *Ibid.*, Executive Summary, at xi.

<sup>9</sup> *Ibid.*, at 24-25.

high-risk hours when the LOLP is high and capacity is valuable. The Integration Study explains clearly that the capacity value of an intermittent resource should not be assessed using approaches that consider wind output during just a few peak hours:

Ad hoc methods that calculate the renewable plant capacity factor over a very small number of hours surrounding the peak may not adequately capture any impacts on system reliability. For example, a wind plant that produces at its rated capacity during a very small number of hours surrounding the peak would be rated with a capacity value at or near its rated capacity. However, such a plant would not provide the same level of capability during other near-peak hours as a conventional plant could potentially provide. Conversely, a wind plant that is given a capacity value of 0 might contribute significant levels of output during near-peak hours when system reliability is still critical.<sup>10</sup>

In fact, the data on wind output in California show that the last statement in this quote is close to the reality of wind output in California: wind output tends to be low during a few peak hours with the highest loads, but wind output is much higher during other, near-peak hours “when system reliability is still critical.” The *2007 RA Report* discusses and documents this fact at length. Unfortunately, the *2007 RA Report* examines the correlation of wind generation to load, not to a reliability metric like LOLP. However, the Integration Study shows the cumulative capacity factor of wind generation in the Altamont, Tehachapi, and San Geronio WRAs over the top 10% of hours in the year (i.e. the top 876 hours), ranked by LOLP (not by load).<sup>11</sup> The figures are similar for all three WRAs – wind generation is relatively low in the top ten or twenty riskiest hours (capacity factors of 0% to 20%), but increases rapidly thereafter to reach cumulative capacity factors of 30% to 32% over all 876 hours. These figures also show the calculated ELCC for each of the WRAs; the ELCCs are 22% to 26%, as the low generation during the 10 or 20 riskiest hours is balanced by much higher generation in the other not-quite-as-risky, near-peak hours. Thus, the Integration Study shows clearly that the capacity value of wind resources in California cannot be assessed simply by looking at a few data points of wind output during a few peak hours.

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<sup>10</sup> *Ibid.*, at 26.

<sup>11</sup> See Figures 3.15, 3.16, and 3.17 on pages 37-38 of the Integration Study.

The Commission used the results of the Integration Study in Decision 04-07-029, which adopted criteria for the LCBF evaluation of bids from new RPS resources. In that order, the Commission adopted the ELCC approach to determine the capacity value of wind resources:

The immediate capacity issue arises from a focused Commission directive in D.03-06-071 (p. 30), establishing that the capacity value of as-available resources will be set by the Commission with reference to the CEC Integration Study.

[Footnote: The values developed in the Integration Study are for each technology's Effective Load Carrying Capability (ELCC), which can be understood as a refined method of calculating capacity that captures its value in relation to system demand. Parties have used ELCC and capacity value interchangeably in briefs. To be precise, what we are adopting here are ELCC values, and we endorse the continued use of ELCC calculations in future RPS policy development, as embodied in scheduled updates to the Integration Study and subsequent Commission decisions.]...

... For wind resources, we adopt a capacity value that is an average of those found in the Integration Study for the existing resources in the state's three principal wind resource areas (Altamont, San Geronio, and Tehachapi): 24%.<sup>12</sup>

D. 04-07-029 emphasized that the Integration Study values should provide “a lower bound to the capacity value a utility should impute to a wind resource bid into its RPS solicitation.”<sup>13</sup> Thus, the Commission has endorsed the use of the ELCC analysis presented in the Integration Study as a conservative measure of the capacity value of wind resources under the RPS program.

In its prior orders establishing the RA program, the Commission has not adopted the use of ELCC values for RA counting purposes. However, the method that the Commission has selected – historical wind output in the Standard Offer No. 1 (SO1) on-peak period, averaged over the most recent three years – produces results that are reasonably close to, and are validated by, the ELCC method, as shown in **Table 2** below. Thus, the Commission has adopted two methods for valuing wind capacity, one for determining wind's contribution to RA requirements and another for valuing wind capacity in new RPS contracts. Both methods assess wind output across many peak hours. The SO1 on-peak period is noon to 6 p.m. on summer weekdays, or about 130 hours per month. The ELCC approach assesses the capacity value of wind in all hours

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<sup>12</sup> D. 04-07-029, at 19-20.

<sup>13</sup> *Ibid.*, at 20 (emphasis added).

of the year, and reflects the fact that wind facilities produce at high levels during the many near-peak, risky hours when system demand – and its need for capacity – are very high . Although the RA counting rules and the Integration Study’s sophisticated ELCC analysis do not produce results that agree for all WRAs, both methods typically produce capacity values for wind that exceed 20% of installed wind capacity.

#### IV. THE COMMISSION SHOULD CONSIDER WHAT OTHER STATES AND CONTROL AREA OPERATORS HAVE ADOPTED FOR THE CAPACITY VALUE OF WIND

California is not the only state that is adding significant amounts of wind generation to its portfolio. California currently ranks second in installed wind capacity; Texas is first. Other states and system operators also are facing the issue of how to count the capacity provided by intermittent generation. CalWEA strongly urges the Commission not to decide this issue in a vacuum, but to look to how other states with significant wind resources are handling this issue.

CalWEA commends the Energy Division for providing Table 14 in its *2007 RA Report* that summarizes the approaches to this issue elsewhere in the U.S. As shown in this table, ELCC is the predominant methodology used elsewhere in the U.S. to determine the capacity value of wind. Significantly, the table in the *2007 RA Report* does not reflect the fact that, in 2007, ERCOT – the control area serving most of Texas and the control area with the largest amount of installed wind generation in the U.S. – adopted an ELCC calculation to determine the contribution of wind resources to reserve margins in Texas.<sup>14</sup> Prior to this change, ERCOT had used the historical capacity factor of wind generation from hours ending 1600 - 1800 on weekdays in July and August (about 16%), adjusted by the equivalent forced outage rate (EFOR) for a combustion turbine (CT). This method produced a capacity value for wind that was just 2.6% of installed wind capacity. In changing its approach, ERCOT recognized that the old approach in effect double-penalized wind both for its own intermittency as well as for the EFOR of a combustion turbine.

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<sup>14</sup> A description of ERCOT’s change in approach can be found at [http://www.ercot.com/meetings/tac/keydocs/2007/0330/11.\\_Draft\\_GATF\\_Report\\_to\\_TAC\\_-\\_Revision\\_2.doc](http://www.ercot.com/meetings/tac/keydocs/2007/0330/11._Draft_GATF_Report_to_TAC_-_Revision_2.doc).

A review of the practices elsewhere in the U.S. also shows that all other states and control areas, but one, assess the capacity value of wind using the average or expected wind generation over a specified set of hours. Only one region, the Southwest Power Pool (SPP), uses an “exceedence” method that sets the capacity value of wind based on the capacity provided in at least a certain percentage of peak hours. And SPP uses the exceedence approach only for long-range planning, not for more operational purposes such as setting short-term reserve margins.<sup>15</sup> CalWEA will discuss below why the exceedence methods that some parties have proposed in this case discriminate unduly against intermittent renewables in comparison to fossil-fuel resources, and effectively result in an inappropriate double de-rating of intermittent capacity.

## V. ANALYSIS OF PARTIES’ PROPOSALS FOR THE RA VALUE OF WIND

CalWEA presents below a comparison of the methods proposed in this case for determining the RA value of wind. All parties appear to recommend the use of a rolling average of the three most recent years of data. We are aware of the following proposals from the parties:

- **CalWEA.** Retain the current methodology, using wind generation for the SO1 on-peak period for all days, not just weekdays. This is also the Energy Division’s Recommendation 5A in its *2007 RA Report*.
- **Energy Division Proposal 5B.** Use wind generation from all hours, weighted by a load-based weighting factor that emphasizes the highest load hours. This load-based weighting factor is essentially a proxy for LOLP.
- **PG&E.** Use wind generation in the top 10 load hours each month.
- **CAISO “3x3” Proposal.** Use wind output in the top 3 load hours of the 3 days in the month with the highest peak loads.
- **CAISO Exceedence Proposal.** Use wind output from the top 5 load hours of the top 6 days of peak demand each month, then calculate the wind output that is exceeded in 70% of these hours.

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<sup>15</sup> See M. Milligan and K. Porter, “The Capacity Value of Wind in the United States: Methods and Implementation,” *The Electricity Journal*, volume 19, issue 2 (March 2006), at 96. This is a version of the Milligan / Porter work referenced in the *2007 RA Report*, at Table 14.

- **Edison / SDG&E.** Use wind output from the SO1 on-peak period for May-September, and from 10 a.m. to 8 p.m. during other months. Set the NQC based on the wind output that is exceeded in 80% of these hours.
- **Energy Division Proposal 5C.** Use wind generation from the top 10% of load hours, then determine the output that is exceeded in 85% of these hours.

CalWEA has obtained from PG&E and Edison hourly data on their purchases of wind generation over the last three years (2005 - 2007) in California's five major WRAs.<sup>16</sup> This appears to be the data set that Energy Division used in its *2007 RA Report*. **Table 2** shows the Net Qualifying Capacities (NQC) that CalWEA has calculated using the above proposals, expressed as a percentage of the total nameplate wind capacity in each WRA.<sup>17</sup> CalWEA also includes in this table wind NQC values for California determined using the methods employed at two other major control areas in the U.S., the Mid-American Power Pool (MAPP) and the PJM Interconnection (PJM). MAPP uses wind output in the peak hour of each month, plus the two hours before and after the peak hour. PJM looks at a rolling three-year average of the wind capacity factor from 3 p.m. to 7 p.m. in the months of June - August. Significantly, both the MAPP and PJM methods use an average or expected value for wind generation over a peak period, and not an exceedence approach. As a point of reference, Table 2 also shows the wind ELCCs for Altamont, Tehachapi, and San Geronio, as calculated in the Integration Study. **Table 3** shows the monthly details of the NQC for each proposal.

CalWEA also has examined the trend in NQC from 2005 to 2007. Generally, wind NQC have increased from 2005 to 2007, particularly in the Solano WRA where significant amounts of new wind capacity, using larger, state-of-the-art turbines, have been installed. The new turbines operate at lower wind speeds, are more efficient, and produce power at higher capacity factors. As a result of this improving performance, the current RA counting rules

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<sup>16</sup> Altamont, Pacheco Pass, and Solano for PG&E; Tehachapi and San Geronio for Edison.

<sup>17</sup> For the two CAISO proposals, CalWEA has used the CAISO's own calculations, which may use a somewhat different data set than provided by the utilities. CalWEA has calculated wind NQC values for the CAISO's two proposals, using the utility data. We did not find significant differences from the CAISO's reported results for the initial CAISO "3x3" proposal. However, our calculated NQC for the CAISO's second, 70% exceedence proposal are almost twice as high, on average, than the CAISO's calculated results. CalWEA does not yet understand the reason for this discrepancy.

**Table 2**

**Summary of Annual Wind NQC Values for the Various RA Counting Approaches**

<b><u>Methodology</u></b>	<b><u>Altamont</u></b>	<b><u>Pacheco</u></b>	<b><u>Solano</u></b>	<b><u>San Geronio</u></b>	<b><u>Techachapi</u></b>	<b><u>Wtd. Avg. by MW</u></b>
<b><u>Expected Value Methods</u></b>						
CPUC Current RA Rules	13%	17%	9%	26%	38%	27%
ELCC Integration Study	26%			24%	22%	23%
MAPP	9%	12%	14%	18%	22%	18%
Energy Division 5b - load wtd.	11%	14%	16%	18%	22%	18%
PG&E	7%	11%	11%	11%	17%	13%
CAISO 3x3	6%	8%	15%	12%	15%	12%
<b><u>Exceedence Methods</u></b>						
SCE / SDG&E - 80%	4%	5%	8%	9%	10%	8%
CAISO 5x6 - 70%	2%	0%	2%	2%	5%	3%

**Summary of Summer (June - August) Wind NQC Values for the Various RA Counting Approaches**

<b><u>Methodology</u></b>	<b><u>Altamont</u></b>	<b><u>Pacheco</u></b>	<b><u>Solano</u></b>	<b><u>San Geronio</u></b>	<b><u>Techachapi</u></b>	<b><u>Wtd. Avg. by MW</u></b>
<b><u>Expected Value Methods</u></b>						
CPUC Current RA Rules	23%	33%	18%	31%	39%	32%
PJM Summer	26%	32%	33%	30%	33%	31%
MAPP	21%	25%	29%	32%	37%	31%
Energy Division 5b - load wtd.	20%	23%	25%	22%	26%	24%
PG&E	10%	16%	16%	14%	19%	16%
CAISO 3x3	9%	15%	15%	12%	17%	14%
<b><u>Exceedence Methods</u></b>						
SCE / SDG&E - 80%	11%	14%	20%	17%	17%	16%
CAISO 5x6 - 70%	2%	20%	11%	9%	13%	9%

**Table 3**

**Monthly Summary of Wind RA Counting Proposals**

**1. CalWEA - Retain Current Methodology**

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
Altamont	2%	4%	10%	13%	22%	31%	21%	17%	16%	10%	3%	3%	13%
Pacheco	3%	7%	12%	19%	28%	44%	31%	25%	21%	11%	5%	3%	17%
Solano	0%	1%	5%	7%	13%	21%	20%	14%	12%	7%	2%	1%	9%
San Geronio	14%	20%	31%	40%	41%	42%	28%	22%	24%	20%	18%	17%	26%
Techachapi	24%	32%	44%	58%	59%	57%	33%	27%	33%	30%	29%	28%	38%
													<b>27%</b>

**2. MAPS Approach (average wind for 4 hours about monthly peak)**

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
Altamont	1%	3%	6%	2%	18%	17%	21%	24%	18%	1%	0%	0%	9%
Pacheco	3%	13%	6%	1%	28%	23%	31%	22%	14%	0%	0%	0%	12%
Solano	0%	5%	0%	7%	31%	29%	23%	34%	27%	6%	2%	5%	14%
San Geronio	30%	19%	15%	12%	38%	48%	27%	21%	5%	1%	1%	5%	18%
Techachapi	31%	27%	22%	12%	24%	45%	36%	30%	17%	0%	16%	9%	22%
													<b>18%</b>

**3. Energy Division Exponential Approach (exp=5)**

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
Altamont	3%	3%	9%	14%	21%	23%	20%	16%	16%	9%	3%	2%	11%
Pacheco	6%	8%	12%	15%	25%	27%	22%	18%	17%	11%	4%	2%	14%
Solano	4%	6%	7%	15%	25%	29%	26%	21%	20%	10%	8%	21%	16%
San Geronio	10%	16%	26%	27%	27%	29%	20%	19%	13%	15%	9%	6%	18%
Techachapi	16%	21%	26%	28%	29%	30%	26%	23%	16%	18%	19%	16%	22%
													<b>18%</b>

**4. PG&E Proposal**

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
Altamont	2%	5%	6%	5%	18%	9%	12%	8%	13%	2%	2%	0%	7%
Pacheco	1%	14%	14%	6%	23%	21%	18%	10%	13%	4%	2%	3%	11%
Solano	4%	9%	3%	6%	23%	20%	18%	10%	18%	3%	10%	3%	11%
San Geronio	7%	22%	22%	9%	17%	20%	13%	10%	4%	4%	3%	5%	11%
Techachapi	16%	29%	23%	11%	14%	20%	19%	19%	15%	4%	17%	16%	17%
													<b>13%</b>

**Table 3**

**5. CAISO 3x3 Proposal**

calculated

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
Altamont	3%	6%	6%	12%	16%	9%	12%	7%	13%	1%	2%	1%	7%
Pacheco	3%	20%	7%	12%	20%	19%	20%	7%	17%	3%	0%	5%	11%
Solano	3%	12%	4%	10%	21%	18%	18%	9%	20%	3%	8%	3%	11%
San Gorgonio	11%	21%	18%	9%	20%	17%	12%	8%	6%	5%	2%	6%	11%
Techachapi	17%	33%	23%	15%	19%	17%	18%	16%	15%	4%	16%	11%	17%
													<b>13%</b>

values from Table 1 -- CAISO preliminary results

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
Altamont	4%	6%	4%	4%	13%	5%	11%	7%	11%	4%	4%	2%	6%
Pacheco	2%	13%	7%	0%	13%	11%	16%	6%	14%	6%	0%	4%	8%
Solano	5%	16%	12%	9%	29%	17%	25%	13%	27%	9%	13%	3%	15%
San Gorgonio	15%	16%	23%	12%	19%	12%	12%	7%	4%	6%	3%	10%	12%
Techachapi	16%	21%	27%	18%	15%	9%	12%	13%	9%	4%	18%	11%	15%
													<b>12%</b>

**6. CAISO Exceedence Proposal**

calculated

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
Altamont	0%	2%	1%	3%	4%	4%	2%	1%	2%	1%	0%	0%	2%
Pacheco	0%	0%	3%	13%	27%	28%	32%	0%	14%	12%	2%	0%	11%
Solano	0%	4%	0%	1%	12%	13%	9%	5%	6%	0%	0%	0%	4%
San Gorgonio	0%	16%	6%	5%	12%	22%	4%	2%	2%	0%	0%	2%	6%
Techachapi	4%	16%	3%	9%	9%	14%	13%	12%	6%	2%	2%	5%	8%
													<b>6%</b>

values presented by the CAISO

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
Altamont	2%	2%	1%	1%	2%	3%	4%	3%	3%	1%	2%	2%	2%
Pacheco	0%	0%	0%	0%	0%	2%	1%	0%	0%	0%	0%	0%	0%
Solano	0%	0%	0%	1%	9%	11%	4%	4%	2%	0%	0%	0%	2%
San Gorgonio	2%	4%	1%	4%	3%	5%	2%	3%	2%	1%	0%	1%	2%
Techachapi	4%	5%	3%	5%	4%	5%	9%	6%	3%	2%	3%	6%	5%
													<b>3%</b>

**7. SCE / SDG&E Proposal**

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
Altamont	0%	0%	1%	2%	9%	13%	14%	6%	3%	1%	0%	0%	4%
Pacheco	0%	0%	0%	0%	13%	19%	17%	7%	2%	0%	0%	0%	5%
Solano	0%	1%	1%	5%	14%	19%	25%	16%	8%	1%	1%	1%	8%
San Gorgonio	1%	1%	7%	9%	28%	33%	12%	8%	8%	2%	1%	1%	9%
Techachapi	3%	4%	7%	13%	25%	24%	17%	11%	5%	5%	4%	3%	10%
													<b>8%</b>

produce NQCs based on 2005 - 2007 data that are somewhat higher than the wind ELCC values calculated in the Integration Study, which was completed late in 2003.

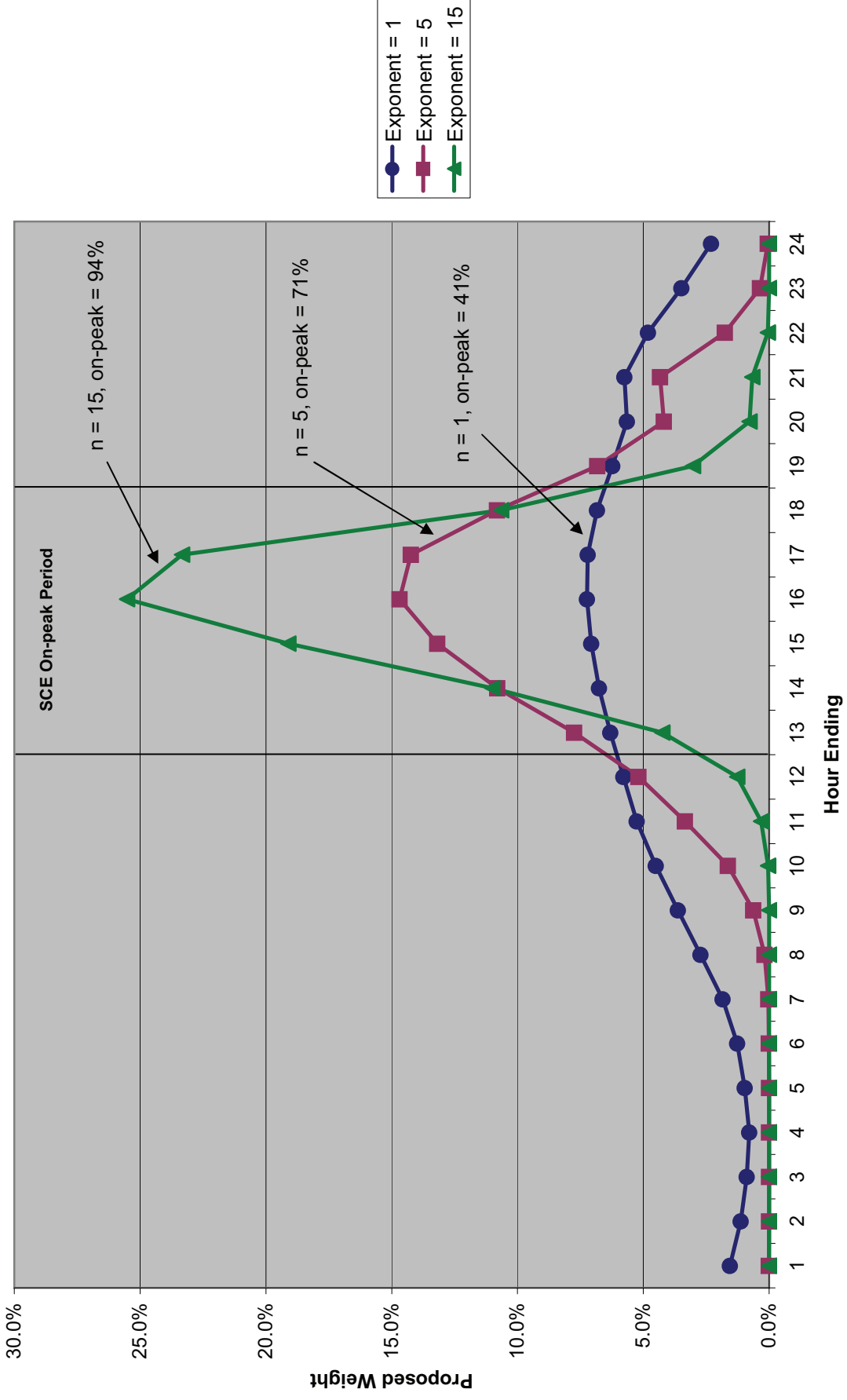
The MAPP method samples a relatively small number of hours around the monthly peak hour – the peak hour plus the two hours before and after the peak. Nonetheless, the MAPP method produces similar results to Energy Division’s Proposal 5B, which is based on wind output in all hours, weighted by a percentile measure of the load in each hour raised to the fifth power, as a proxy for LOLP. **Figure 1** shows the weighting factor used in Proposal 5B, for exponents  $n=1$ ,  $n=5$ , and  $n=15$ , using July 2007 CAISO hourly load data. This figure shows that the portion of the weighting factor that falls within the summer on-peak period (weekdays, noon – 6 p.m.) is 41% for  $n=1$ , 71% for  $n=5$ , and 94% for  $n=15$ . CalWEA believes that this information shows that the Energy Division’s weighting factor with  $n=5$  (71% on-peak) provides the best match to SCE’s LOLE model results for the summer peak months (70% on-peak). CalWEA has obtained very similar results for other recent summer months. Thus, CalWEA concludes that the Energy Division’s Proposal 5B, using a load-based weighting with an exponent of five, reasonably reflects the impacts of wind generation on overall system reliability (as do the current RA counting rules).

In contrast to the MAPP and Energy Division 5B methods, the PG&E and CAISO “3x3” proposals produce lower NQCs because they tend to focus more narrowly on just one to three peak hours on each high-demand day. Both PG&E and the CAISO justify their methods as reasonable simply because they produce lower wind NQCs; neither party has made a serious effort to show that their proposals have any relationship to the actual impact of wind generation on system reliability in California.

The exceedence approaches advanced by Edison / SDG&E and the CAISO produce very low wind NQCs. In essence, the exceedence approaches de-rate wind capacity twice: first, by using the actual capacity factor of intermittent wind generation over a peak period and, second, by applying an exceedence factor that ignores all wind energy that cannot be produced at the 70% - 85% capacity factor of a traditional baseload plant. The double de-rating of wind capacity in the exceedence methods result in NQCs far below the ELCC value of wind calculated in the

**Figure 1**

**Energy Division Proposed RA Weighting Formula  
(July 2007 Example)**



Integration Study. In many hours, wind generation will produce at levels far higher than these very low NQCs, but all of this power is assumed to make no contribution to reliability. However, the comprehensive ELCC analyses show that there is a reliability value in the wind generation that is de-rated by the exceedence methods. ERCOT's discarded method of establishing the capacity value of wind also applied a double de-rating to the capacity value of wind: once through wind's actual capacity factor, and again by applying the EFOR of a CT to wind's capacity factor. As discussed above, ERCOT has revised its approach to remove this double de-rating, and has moved to the use of an ELCC metric. CalWEA strongly urges the Commission to profit from ERCOT's experience, and not to regress by adopting a punitive exceedence method in California.

CalWEA is very concerned that the exceedence methods would result in the unfair and discriminatory treatment of wind generation, compared to fossil-fueled thermal resources. The Commission should recognize that the output of all electric generating technologies varies with ambient conditions; to a degree, all electric generators are intermittent. This basic physical fact is not recognized in the Commission's current RA counting rules. For example, as noted in the *2007 RA Report*,<sup>18</sup> the NQC for thermal generation is based on a unit's PMax, its maximum performance capability, without any de-rating based on ambient conditions, forced outages, or actual performance during peak periods. Yet, in reality, the capacity of new, dry-cooled combined-cycle plants will be de-rated by about 10% as temperatures increase from 60F to the 100F and above routinely experienced on hot summer days in California, when electric demands peak.<sup>19</sup> In addition, such plants can have forced outage rates of 5%.<sup>20</sup> Thus, even the newest thermal units may operate during heat waves at capacity factors that are 10% - 15% below their NQCs. Yet the NQCs of fossil-fueled thermal plants are not adjusted to reflect this de-rating due to ambient conditions, forced outages, and actual performance at peak. Instead, such

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<sup>18</sup> Section 4.4, pages 18-19.

<sup>19</sup> The California Energy Commission published a study in 2006 on water use at power plants in California that includes this information on the de-rating of dry-cooled CCGTs in California. See "Cost and Value of Water Use at Combined-Cycle Power Plants" (CEC Publication CEC-500-2006-034, April 2006), at 21-23 and Figure 8.

<sup>20</sup> The CPUC's current market price referent assumes a forced outage rate of 4.6% for a new dry-cooled CCGT. See Resolution E-4118, at 13.

“intermittency” in the output of thermal units is accommodated in the 15% planning reserve margin, even though the amount of installed thermal capacity in California is very large. The intermittency of California’s thermal generation is anticipated to increase in the future, as environmental and water-use concerns increasingly restrict the use of the more efficient one-through or wet cooling technologies that minimize the loss of capacity on hot days. In contrast, the exceedence proposals of Edison / SDG&E and the CAISO would force the NQCs of individual wind plants to include virtually all of the worst-case reductions of wind output due to ambient conditions, by setting wind NQCs as low as just 3% of installed wind capacity. Wind generation thus would receive virtually no benefit from the 15% planning reserve margin, even though the amount of wind capacity in California is still relatively modest. Such a result clearly would discriminate unfairly against wind generation and other intermittent renewables, compared to thermal generation.

VI. A TOO-LOW RA VALUE FOR WIND MAY RESULT IN THE OVER-PROCUREMENT OF RA RESOURCES, AT A POTENTIAL COST TO RATEPAYERS OF \$2.0 to \$3.75 BILLION

Edison/SDG&E and the CAISO have proposed RA counting rules for wind using exceedence methods that would reduce the RA value of wind by 20% to 25% of the installed capacity of wind. Given an installed wind capacity of about 2,000 MW today on the CAISO grid, this would result in an immediate increase in RA needs of 400 - 500 MW. Installed wind capacity in California may grow to perhaps 10,000 MW in the next five years. With 10,000 MW of wind capacity, the reduction in the RA value of wind that Edison/SDG&E and the CAISO have proposed would require an additional 2,000 to 2,500 MW of back-up generation. New combustion turbine capacity will cost \$1,000 to \$1,500 per kW,<sup>21</sup> so 2,000 to 2,500 MW of new peaking capacity represents a long-term cost to ratepayers of \$2.0 to \$3.75 billion. CalWEA believes that a state-of-the-art analysis of the reliability value of wind to the California electric system would show, as have previous ELCC studies, that these costs do not need to be incurred

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<sup>21</sup> The 250 MW of new peaking units that the Commission ordered Edison to build in August 2006 cost \$1,456 per kW. See A. 07-12-029. Recent CEC estimates on the costs of new CT capacity in California are in excess of \$1,000 per kW. See “Comparative Costs of California Central Station Electricity Generation Technologies,” (December 2007, CEC Publication CEC-200-2007-011-SF), at Table 19. This CEC report is available at <http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF>.

in order for 10,000 MW of wind to be integrated successfully. At a minimum, the state should proceed very carefully in this area, and should rely on updated, state-of-the-art analysis, before making changes that would trigger additional costs of this magnitude.

The Commission also should proceed cautiously given the results of a major recent CEC study of integrating up to 33% renewables into the California grid. This work, the Intermittency Analysis Project (IAP Study), included scenarios with up to 12,000 MW of wind capacity.<sup>22</sup> In the long-term procurement plan hearings last year (R. 06-02-013), the CEC's witness on renewable issues, Ms. Raitt, summarized the results of the IAP's work:

These findings showed that even with 33 percent renewables (with over 12 GW of wind in CA ISO area) at the hourly level there were no significant operational problems observed. In all scenarios studied, during summer peak conditions, the statewide electrical system had sufficient flexibility and adequate resources with 20 percent and 33 percent renewables. Where intermittency does have some noticeable impact was during off-peak and morning load rise conditions. These impacts though small were quantified in the study and suggested mitigation options were provided.<sup>23</sup>

The results of the IAP strongly suggest that California can achieve its ambitious goals for renewable development without the need to install substantial amounts of back-up generation, even with a very significant penetration of intermittent renewables, including large amounts of wind.

## VII. HOW SHOULD THE COMMISSION MOVE FORWARD ON THIS DIFFICULT ISSUE?

CalWEA's primary recommendation in this case is that the Commission should maintain the current RA counting rules for intermittent renewable generation, pending the completion of new ELCC studies of wind generation in California. It is CalWEA's understanding that these studies are underway at UC Davis' California Wind Energy Collaborative, with initial results to be delivered to the CEC by the end of the month. CalWEA supports the Energy Division's

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<sup>22</sup> The final IAP Report is available at [http://www.energy.ca.gov/pier/final\\_project\\_reports/CEC-500-2007-081.html](http://www.energy.ca.gov/pier/final_project_reports/CEC-500-2007-081.html).

<sup>23</sup> R. 06-02-013, CEC / Raitt, Exhibit 63e, at 22 (emphasis added).

Proposal 5A to expand the hours used in the wind NQC calculation to include weekends and holidays as well as weekdays, in order to incorporate more data into the calculation of wind NQCs..

As a second option, CalWEA believes that the Energy Division's Proposal 5B ( with an exponent no greater than 5) is acceptable, because, while it produces a measured reduction in wind NQCs, this counting method has a reasonable connection to the actual contribution of wind to system reliability (i.e. to reducing system LOLP). As discussed above, this proposal uses a load-based weighting that correlates well with Edison's recent LOLE study. The adoption of Proposal 5B would be a reasonable step that would not discriminate unduly against wind, pending the completion of new ELCC studies based on up-to-date wind generation data.

Finally, the Commission should recognize that ambient conditions during heat waves also adversely and substantially impact the output of thermal generation. Thermal generators currently receive a "free ride" on such impacts through the planning reserve margin. These impacts will increase in magnitude in the future as a result of the loss of once-through cooling at coastal power plants and of reductions in the use of wet cooling as pressures on California's scarce fresh water resources increase. The impact on the adequacy of California's generation resources of an unexpected 10% fluctuation in the output at peak of 25,000 MW of thermal generation has five times the impact of an unforeseen 20% variation in 2,500 MW of wind resources. The Commission has the responsibility to set RA counting rules so that all generators – renewable and fossil-fueled – derive an equitable benefit from the flexibility of the 15% planning reserve margin. The Commission should not set the counting rules for intermittent renewable generation so stringently that almost all of the benefits of the planning reserve margin accrue to thermal generation. Furthermore, the Commission should re-examine the method for setting the NQCs of thermal generation to ensure that the intermittency and actual performance of the state's thermal resources are reflected in their NQCs, just as the Commission is doing in this case for intermittent renewable generation.

CalWEA appreciates the opportunity to submit these opening comments.

Respectfully submitted,

/ s / R. Thomas Beach

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On Behalf of  
**THE CALIFORNIA WIND ENERGY ASSOCIATION**

May 12, 2008

## **Attachment A**

Southern California Edison's  
Current Loss-of-Load Expectation (LOLE),  
by time-of-use period

A. 08-03-002 (Exhibit SCE-2)

1                                   c)     Loss Of Load Expectation

2                                   There is always some likelihood, however small, that the electricity system will  
3 be unable to serve demand. The risk of a generation shortage can be reduced by over-supplying  
4 generation, but over-investment and high operating costs would significantly increase customer rates.  
5 Determining the optimum supply and demand balance requires the study of expected system operations  
6 using a probabilistic risk assessment approach. Analysis of a system’s LOLE is one appropriate risk  
7 assessment approach – it is a measure of system reliability that indicates the ability (or inability) to  
8 deliver energy to the load. An LOLE analysis can provide insight into the appropriate planning reserve  
9 requirement for each load-serving entity (LSE) in a region.<sup>31</sup>

10                                  The LOLE metric provides a method for allocating annualized capacity value  
11 across time-of-use periods in proportion to when the loss of load is likely to occur.<sup>32</sup> For example, if the  
12 LOLE is greatest in the summer period primarily due to load conditions, particularly during the on-peak  
13 period, then most of the value SCE attributes to capacity will be assigned to that period. Similarly, if the  
14 probability for loss-of-load is nearly zero during winter off-peak periods, SCE will assign very little  
15 capacity value to that period. LOLE makes it possible to evaluate the relative reliability contribution of  
16 different resources across a range of time-of-use periods.

17                                  SCE used the Market Analytics model and the “Medium Load Plan Scenario”  
18 from its 2004 LTPP as the basis to calculate a probabilistic estimate of the fraction of time the SCE  
19 system is unable to meet demand.<sup>33</sup> SCE’s analysis employed a Monte Carlo approach by way of two-  
20 factor mean reversion sampling of loads and resources. The analysis performed 250 simulations each  
21 unique with regard to hourly supply and demand. From the Monte Carlo analysis, SCE was able to

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<sup>31</sup> In D.04-10-035 the Commission directed load serving entities under its jurisdiction to plan based upon meeting a 15 to 17 percent resource adequacy requirement. This implicitly reflects a balancing of customer risks and costs.

<sup>32</sup> The purpose of SCE’s LOLE analysis is not to forecast the precise timing of future low-reserve margin events, nor is it to forecast the absolute magnitude of any single loss-of-load event. Rather, it is intended to be a relative distribution of risk used to allocate capacity value across time of use periods.

<sup>33</sup> SCE relied on this same analysis in SCE’s 2006 GRC Phase 2 proceeding (A.05-05-023).

1 extract hourly resource availability and loads from each of the 250 simulations. An LOLE event occurs  
2 in hour  $h$  when the load ( $L$ ) exceeds available resources ( $R$ ).

$$3 \quad L_h - R_h > 0$$

4 For each simulation, the load in a particular hour can be compared to each of the  
5 250 Monte Carlo outcomes of resource availability in that same hour. In other words, the load in hour  $h$   
6 is assumed to have the same likelihood of occurring in any of the 250 resource outcomes in hour  $h$ . The  
7 same is true from another viewpoint: the resource availability in hour  $h$  is assumed to have the same  
8 likelihood of occurring in any of the 250 load outcomes in hour  $h$ . Effectively, this approach yields 250  
9  $\times$  250 or 62,500 possible combinations of load and resources in hour  $h$ . The above equation can be  
10 modified to illustrate this method.

$$11 \quad L_{h,i} - R_{h,j} > 0$$

12 Where  $i$  and  $j$  are from the respective simulations for load and resources.

13 The range of loads and resources is determined by stochastic parameters tied to  
14 historical performance. Each load and resource combination is given equal probability of occurring  
15 assuming short-term variations in loads (*i.e.*, weather) and available resources (*i.e.*, forced outages) are  
16 random. Combinations in which available resources are unable to meet the load (hence, loss-of-load)  
17 contribute to the LOLE for that hour. For example, if 125 out of the 62,500 combinations resulted in  
18 loads exceeding available resources, then the LOLE for that hour is 0.2% (125 divided by 62,500), or a  
19 probability of 1 in 500.

20 The hourly LOLE, or stochastic LOLE, is normalized over all hours of the year  
21 such that the sum of the normalized LOLE equals 1. This creates a relative relationship of the hourly  
22 LOLE across time. The result of SCE's LOLE analysis is shown in the Table below.

**Table I-8**  
**Relative LOLE Factors (Sum = 1)**

Summer			Winter	
On-Peak	Mid-Peak	Off-Peak	Mid-Peak	Off-Peak
0.701	0.205	0.009	0.081	0.004

1                   The stochastic LOLE approach takes into account as much uncertainty as SCE  
2 can reasonably capture within the limitations of the model. These are the same uncertainties facing  
3 today's system operators (load forecast, supply availability, and hydro conditions). This approach  
4 provides a reasonable estimation of the relative risk of not serving the load in any given period, realizing  
5 that not all of the market's inefficiencies can be captured in any single model.

6                   **2.     Delivery-Related Marginal Costs**

7                   Delivery-related marginal costs are the marginal costs of delivering electricity to  
8 customers through the transmission and distribution (T&D) system. The calculation of delivery-related  
9 marginal costs involves identifying design demand; a component related to a customer's maximum  
10 demand (kW). SCE proposes to use the NERA regression methodology on 10 years of historical data  
11 and five years of forecast data to determine delivery-related marginal costs. Consistent with prior  
12 Commission practice, the cost of the final line transformer, service drop, and meter are removed from  
13 the distribution component and included in the customer component.

14                   a)     NERA Regression Methodology

15                   Ten years of historical expense on Transmission and Distribution capital additions  
16 as reported in the FERC Form-1 are adjusted to remove the cost of replacement capital, so only expenses  
17 related to load and customer growth are captured. Five years of forecast load growth expense is taken  
18 from studies that support SCE's 2009 GRC request. The forecast data is on a closed to plant basis and  
19 includes capitalized allowed funds used during construction (AFUDC) and administrative and general  
20 (A&G) overhead, so that historical and forecast are on a similar basis. Historical and forecast annual  
21 peak load for the A-Bank (transmission) and B-Bank (distribution) were collected. The NERA



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